

Staff Briefing Papers

Meeting Date Thursday, July 30, 2026

Agenda Item *5**

Company Northern States Power Company d/b/a Xcel Energy

Docket No. E002/M-25-142

In the Matter of Xcel Energy's 2025 Integrated Distribution Plan

- Issues**
1. Should the Commission accept or reject Xcel Energy's 2025 Integrated Distribution Plan (IDP)?
 2. Should the Commission require any additional information or adjust any of the IDP filing requirements for Xcel Energy?
 3. Should the Commission take any other action related to Xcel Energy's IDP?

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**

Xcel Energy – 2025 Integrated Distribution Plan (Public and Trade Secret)

Date

October 31, 2025

Initial Comments

City of Minneapolis

February 26, 2026

Center for Energy and Environment

February 26, 2026

Environmental Law and Policy Center, Cooperative Energy Futures, and Vote Solar (ELPC/CEF/VS)

February 26, 2026

Fresh Energy

February 26, 2026

Joint Solar Parties

February 26, 2026

Department of Commerce (Public and Trade Secret)

February 27, 2026

Reply Comments

Xcel Energy

March 19, 2026

LIUNA Minnesota/North Dakota

April 23, 2026

City of Minneapolis

April 23, 2026

Center for Energy and Environment

April 23, 2026

Office of the Attorney General

April 23, 2026

Fresh Energy

April 23, 2026

Environmental Law and Policy Center, Cooperative Energy Futures, and Vote Solar

April 23, 2026

Citizens Utility Board of Minnesota

April 23, 2026

Joint Solar Parties

April 23, 2026

Department of Commerce (Public and Trade Secret)

April 23, 2026

Other Documents

Xcel Response to PUC IRs 1 through 12

May 18, 2026

May 21, 2026

June 1, 2026

Department Response to PUC IRs 1 through 10

May 18, 2026

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I. Acronyms

Acronym	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AOM	Advanced Outage Management
ARR	Avoided Revenue Requirement
ASHP	Air Source Heat Pumps
BE	Beneficial Electrification
BTM	Behind the Meter
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CELI	Customers Experiencing Lengthy Interruptions
CEMI	Customers Experiencing Multiple Interruptions
CMO	Customer Minutes Out
CSG	Community Solar Garden
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DF	Dependability Factor
DFPV	Dependability Factor for Photovoltaics
DG	Distributed Generation
DGWG	Distributed Generation Working Group (DGWG)
DI	Distributed Intelligence
DR	Demand Response
DSM	Demand Side Management
ECO	Energy Conservation & Optimization
ELPC	Environmental Law and Policy Center
ELR	End of Life Replacement
EPSS	Enhanced Powerline Safety Settings
EV	Electric Vehicle
FAN	Field Area Network
FE	Flexible Energization
FERC	Federal Energy Regulatory Commission
FI	Flexible Interconnection
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front of the Meter
GIS	Geographical Information System or Geospatial Information System
HAN	Home Area Network

HCA	Hosting Capacity Analysis
ICE	Interruption Cost Estimate
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
LBNL	Lawrence Berkley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MISO	Midcontinent Independent System Operator
MN DIP	Minnesota Distributed Energy Resources Interconnection Process
N-0	System intact operating condition
N-1	Single contingency operating condition
NSPM	Northern States Power Company-Minnesota (Minnesota, North Dakota, and South Dakota operating company)
NWA	Non-Wires Alternatives
O&M	Operations and Maintenance
PNL	Planned Net Loading
PSPS	Public Safety Power Shutoffs
PSRP	Planning Standard Review Process
RFI	Request for Information
RFP	Request for Proposal(s)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TCR	Transmission Cost Recovery (Rider)
TEP	Transportation Electrification Plan
TIIR	Technical Interconnection and Interoperability Requirements
TPS	Technical Planning Standard
VPP	Virtual Power Plant
WAN	Wide Area Network

II. Statement of Issues and Docket History

1. Should the Commission accept or reject Xcel Energy's 2025 Integrated Distribution Plan (IDP)?
2. Should the Commission require any additional information or adjust any of the IDP filing requirements for Xcel Energy?
3. Should the Commission take any other action related to Xcel Energy's IDP?

A. Docket History

The Commission established Integrated Distribution Plan (IDP) filing requirements for Northern States Power Company d/b/a Xcel Energy ("Xcel" or "the Company") in its August 30, 2018 Order.¹ The purpose of the Commission's IDP filing requirements is to produce plans that will:

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;
4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
5. Provide the Commission with the information necessary to understand the utility'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.

On September 16, 2024, the Commission accepted Xcel Energy's 2023 IDP with modified filing requirements in its Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements in Docket E-002/M-23-452.² This Order began a series of working groups facilitated by Commission staff to modify the filing requirements in line with the Commission's Order and ahead of the Company's next IDP filing in 2025.

On June 3, 2025, the Commission issued its Notice of Approval of Updated Filing Requirements resulting from the work groups, outlining the newly modified filing requirements for Xcel Energy's 2025 IDP.³

On October 31, 2025, Xcel Energy filed its 2025 Integrated Distribution Plan ("IDP"), 2025 Transportation Electrification Plan ("TEP"), 2025 Proactive Upgrade Proposal ("PUP"), and a certification request for the mobile battery project under Minn. Stat. 216B.2425, subd.3(b). The

¹ Docket No. E-002/CI-18-251, *Order Approving Integrated Distribution Planning Filing Requirements For Xcel Energy* ([August 30, 2018](#)), Attachment

² Docket No. E002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements, September 16, 2024 (hereinafter "2023 IDP Order").

³ Docket No. E-002/CI-18-251/M-23-452/M-25-142, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Notice of Approval of Updated Filing Requirements, June 3, 2025 (hereinafter "updated filing requirements approval").

Commission separately considered, and approved, the TEP, PUP, and Certification requests in the first half of 2026.

On November 13, 2025, the Commission issued a Notice of Comment Period asking parties to answer the following questions regarding the 2025 Xcel Energy IDP:

- Should the Commission accept or reject Xcel Energy’s Integrated Distribution Plan (IDP)?
- Did Xcel Energy adequately address the Commission’s IDP filing requirements and prior Orders, as outlined in Attachment A to this notice?
- Feedback, comments, and recommendations on the following areas of Xcel’s IDP:
 - a. Forecasted distribution budget
 - b. Forecasting results and methodology
 - c. Proactive capacity investments
 - d. Updated Planned Net Load (PNL) methodology and risk analysis results
 - e. Targeted undergrounding proposal
 - f. Proposed cost-benefit analysis for discretionary distribution system investments
 - g. Non-Wires Alternative Analysis
 - h. Distributed Energy Resource Management System (DERMS)
- Other areas of Xcel’s IDP or TEP not listed above, along with any other issues or concerns related to this matter.

By February 27, 2026, the following organizations submitted initial comments:

- The Minnesota Department of Commerce, Division of Energy Resources (Department)
- Environmental Law and Policy Center, Cooperative Energy Futures, and Vote Solar (ELPC/CEF/VS)
- The Center for Energy and Environment (CEE)
- The City of Minneapolis (Minneapolis)
- Fresh Energy
- The Coalition for Community Solar Access, the Minnesota Solar Energy Industries Association, and the Solar Energy Industries Association, collectively the Joint Solar Parties (JSP)

On March 19 Xcel submitted reply comments.

By April 24, the following organizations submitted reply comments:

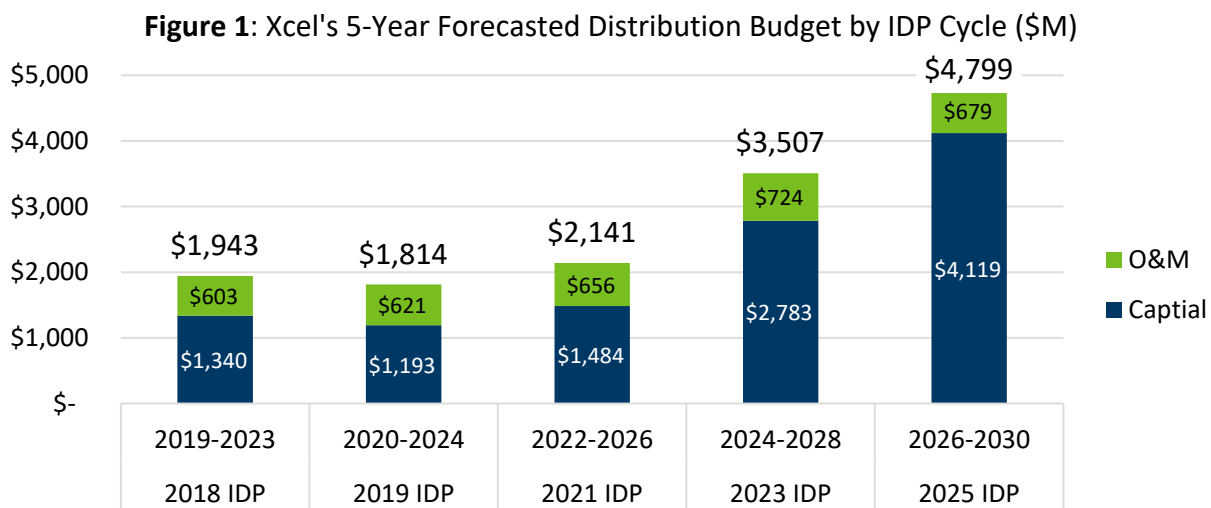
- The Department
- ELPC/CEF/VS
- CEE
- Minneapolis
- Fresh Energy
- JSP
- The Citizens Utility Board of Minnesota (CUB)
- The Office of the Attorney General, Residential Utilities Division (OAG)
- LIUNA Minnesota and North Dakota (LIUNA)

III. Introduction

A. Executive Summary

The following briefing paper summarizes Xcel Energy's 2025 Integrated Distribution Plan (IDP) and stakeholder recommendations. Similar to the 2023 IDP Cycle, Staff has written and separately filed a Joint Briefing Paper that gives an overview of all four utility IDPs and discusses recommendations from the Department that are similar across the filings.

The 2025 IDP is the fifth plan Xcel Energy has filed with the Commission since 2018 and outlines the Company's 2026 through 2030 distribution budget of \$4.8 billion dollars. The prevailing theme in stakeholder comments was concern over the rapidly increasing distribution budget. Figure 1 depicts the increase in the 5-year forecasted budget since the first IDP in 2018.



Stakeholders made numerous recommendations to contain rising distribution costs. The most significant recommendation is the Department of Commerce's proposal to establish a Planning Standard Review Process (PSRP) to review and approve portions of Xcel's engineering and distribution planning standards. Given the magnitude of the Department's proposal, Staff used Lawrence Berkley National Laboratory's (LBNL) State Technical Assistance Program to support its analysis. LBNL's memo is filed as Attachment A to the briefing papers. Below Staff summarizes the major issues raised by stakeholders.

Forecasting and Scenario Analysis (Decision Options 6-8)

The Department questioned whether Xcel's forecast was biased toward over forecasting which could result in the Company overbuilding infrastructure. It recommended a new IDP filing requirement to track its long-term accuracy. Xcel opposed this recommendation and cautioned that forecasts must account for worst case events which will invariably result in what looks like an over forecast.

Cost-Benefit Analysis (CBA) (Decision Options 9-18)

In its 2023 IDP Order, the Commission required Xcel to work with stakeholders to perform cost benefit analysis for discretionary distribution programs. Xcel filed CBAs for the Grid Reinforcement program and End-of-Life Replacement (ELR) Breakers program. The Department and Fresh Energy critiqued multiple aspects of the CBAs and recommended both changes to the analyses and requiring additional CBAs for other discretionary programs. ELPC/CEF/VS, CUB, JSP, and the OAG supported many of the Department's recommendations. Xcel opposed calls for additional CBAs citing a strain on Company resources and the potential blurring of the line between cost recovery and planning.

Value of Reliability (Decision Options 21-23)

The Department disputed Xcel's valuation of reliability by comparing it to MISO Value of Lost Load (VOLL). It recommended opening a new proceeding for all utilities to investigate the valuation of unserved energy and the use of price caps. ELPC/CEF/VS, Fresh Energy, and the City of Minneapolis supported the Department's recommendation. Xcel defended its methodology which uses the industry standard Interruption Cost Estimate (ICE) Calculator developed by LBNL. The Company did not oppose further discussion about the value of reliability but noted many of the topics raised by the Department had been previously addressed in recent Commission proceedings.

Targeted Undergrounding (Decision Options 24-30)

Xcel proposed \$233.7 million from 2026 through 2030 to perform targeted undergrounding to improve reliability. The Commission approved a budget of \$9 million for 2025 and 2026 in the Company's most recent rate case. The Department and ELPC/CEF/VS pushed back against the size of the program and recommended additional analysis to prove the projects are cost effective compared to alternatives and equitably distributed throughout the Company's service territory. Xcel opposed these recommendations as insufficiently developed and explained the Commission already ordered a third-party equity study. LiUNA support a considered and selective approach to targeted undergrounding.

Wildfire Mitigation Plans (Decision Options 31-34)

Xcel included information on its proposed investments to mitigate wildfire risk, which total over \$809 million in capital expenditures for the five-year IDP period. While decisions on the budget for wildfire mitigation occurred in Xcel's recently concluded rate case, in the IDP the Department and ELPC/CEF/VS made recommendations for the Company to file formal Wildfire Mitigations Plans that evaluate the Company's fire risk and justify the proposed spending levels. Xcel did not oppose the recommendation to file WMPs. The Department requested authorization to spend \$300,000 on technical assistance for the review of rate regulated utility WMPs.

Review of Distribution Planning Standards (Decision Options 35-46)

Driven by concern over Xcel's rapidly rising capacity budget, the Department claimed that the Company did not adequately optimize its distribution system and recommended a formal review process for Xcel's engineering and planning standards. Under the proposal the Commission would select standards which would be reviewed for their cost effectiveness and potential alternatives. ELPC/CEF/VS, Fresh Energy, JSP, CUB, Minneapolis and the OAG

supported the Department's recommendations. Xcel strongly objected, stating that planning standards are highly technical, engineering-based criteria necessary for safety and reliability and not discretionary policy preferences. The Department requested \$1.2 million to support the PSRP in its first two years. Staff offers several alternative options to the Department's proposed process, including an independent engineering review of Xcel's planning standards.

Distributed Energy Resource Management System (DERMS) (Decision Options 48-49)

In the 2023 IDP Order, the Commission required Xcel to develop a DERMS roadmap which would guide its deployment which the Company submitted with its 2025 IDP. The Company requested, and received approval for, an initial limited deployment of grid DERMS with the approval of Capacity*Connect in Docket E002/M-25-378. In the present docket, ELPC/CEF/VS advocated for continued oversight of the DERMS rollout to ensure the multi-million-dollar investments are cost-effective and tied to clear use cases before rate recovery is granted. ELPC/CEF/VS also requested Xcel file a complementary market-driven Distributed Power Plant or Virtual Power Plant. The Center for Energy and Environment (CEE) and the Department requested pilots to test various DERMS capabilities. Xcel suggested that any DERMS pilots are better addressed through its Energy Conservation and Optimization (ECO) Triennial Plan, not the IDP.

Flexible Interconnection (FI) Rollout (Decision Option 52)

In its 2023 IDP order the Commission required Xcel to implement static FI prior to dynamic FI. The Joint Solar Parties (JSP) and ELPC/CEF/VS argued that Xcel did not comply with the Order as it dismissed "static" FI (which is available today) and delayed implementation until "dynamic" FI can be rolled out via a new software platform in 2026-2029. They argued this delay exacerbates grid congestion and needlessly stalls hundreds of projects. Xcel countered that static FI has significant operational limitations and that waiting to deploy dynamic FI, enabled by a DERMS, is a more efficient solution.

Planned Net Load (PNL) Methodology (Decision Option 53)

The Commission required Xcel to work with stakeholders to update its PNL methodology to include seasonal differentiation as part of its 2023 IDP decision. PNL is a method to value the contribution solar makes to reducing peak capacity, which can defer the need for system upgrades. ELPC/CEF/VS argued that Xcel did not fully comply with the Commission's order by failing to address stakeholder recommendations on a seasonal differentiation for PNL and recommended immediate implementation of seasonal dependability factors. Xcel defended its methodology but did agree to adopt a seasonal PNL in the 2027 IDP after further methodology refinement. ELPC/CEF/VS requested Xcel file an interim update by the end of the year that includes the requirements necessary to comply with the Commission Order on the 2023 IDP.

Non-Wires Alternatives (NWAs) (Decision Options 54-55)

Xcel is required to conduct an NWA analysis for capacity projects which cost over \$2 million as part of its IDP. Fresh Energy expressed concern that Xcel's NWA solicitations are likely to fail as Xcel only compensates developers based on an "Avoided Revenue Requirement split," rather than the actual installation costs of the DERs. They recommended a restructuring of Xcel's NWA approach if the next RFP fails. The Department argued that Xcel should expand its NWA analysis

to include reliability projects. Xcel objected, stating that emergency and reliability replacements must be implemented immediately and cannot wait for an NWA procurement cycle.

The only required action is for the Commission to either accept or reject the Company's 2025 IDP. However, as in past IDPs, there are numerous other decision options the Commission may adopt to modify future IDPs, cost recovery proceedings, and other aspects of Xcel's distribution planning process.

The most substantive recommendations relate to significant changes to the IDPs and to Xcel's overall planning process. However, to properly set the context for why these recommendations are made, the briefing papers first go over the forecast, budget, reliability, and wildfire sections of Xcel's IDP and the associated recommendations.

B. 2023 IDP Outcomes

In its September 16, 2024 [Order](#) accepting Xcel's 2023 IDP the Commission established several workgroups and additional requirements for the Company, outlined in Table 1.

Table 1: Status of 2023 IDP Order Points

Process	Description	Status
IDP Budget Category Amendments <i>Order Point 7</i>	Modifications to the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data.	Notice issued approving updated filing requirements June 3, 2025
IDP Filing Requirements for Electrification <i>Order Point 8</i>	Modifications to the IDP filing requirements to include discussions of the impacts of electrification where appropriate	Notice issued approving updated filing requirements June 3, 2025
Cost Benefit Analysis <i>Order Points 10-12</i>	Xcel to engage stakeholders on approaches to apply CBA for discretionary distribution programs. Must also define "discretionary" and define CBA methodology and identification of benefits.	Workshops held April 17 and June 3 , 2025. CBAs for two programs included in 2025 IDP filing
Distribution Data Reporting Requirements <i>Order Point 13</i>	Develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets. Develop a comprehensive list of existing distribution data reporting requirements and identify which, if any, pieces of information are missing and should be included in future IDPs.	Data lists created, several meetings held. List of consensus modifications agreed to, but larger list of non-consensus items remains outstanding.

Proactive Grid Upgrades Workgroup <i>Order Point 14</i>	Established a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel.	Framework adopted with September 2, 2025 Order in Docket 24-318. First PUP approved June 5, 2026 Order in Docket 25-142.
Planned Net Load <i>Order Point 17</i>	Xcel to work with stakeholders to refine its planned net load methodology and include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.	Workshops held April 17 , May 8 , and July 9 , 2025. Information included in 2025 IDP.
Flexible Interconnection <i>Order Points 19-21</i>	DGWWG to address Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection.	DGWWG subgroup launched in June, 2026.
DERMS <i>Order Points 22-23</i>	Xcel to file a DERMS deployment roadmap and engage with stakeholders on DERMS implementation plans.	Workshops held June 16 and July 8 , 2025. Roadmap included with Capacity*Connect filing (Docket 25-378) and with 2025 IDP

C. Staff Introduction

The predominant theme among commentors in Xcel's IDP was concern over increasing distribution system expenditures, and especially the forecasted increase in investments to increase distribution system capacity. While there are many options to contain costs and optimize use of the distribution system, there are three major factors over which Xcel has little control that, regardless of Commission action, will result in higher distribution expenditures than past decades:

- The need to replace aging infrastructure
- Rapid inflation for core distribution equipment
- Load growth from electrification

Staff highlights how significant inflation and equipment failure impacted Xcel's actual distribution spending in 2024. When the Company's AMI project is removed from the picture, three categories, transformer purchases, pole replacements, and restoration and failure reserves, made up 44% of the distribution budget in 2024 compared to around 25% from 2018-2023.⁴

⁴ Xcel Response to PUC IR 5.

Staff takes exception to the implication that IDPs as currently structured are unable to properly scrutinize utility spending. While Xcel's distribution budget remains significantly above historical level, Commission action in past IDPs has resulted in substantial reductions to individual programs. The most prominent example is the Proactive System Upgrades to Increase Hosting Capacity and Grid Reinforcement capacity programs. In the 2023 IDP the two programs totaled over \$322 million in forecasted expenditures over four years. The significant planned capital spend across these two categories was a contributing factor to the Commission's direction to create the Proactive Distribution Upgrade Framework. In the 2025 IDP, Xcel eliminated the Proactive Upgrade budget due to the newly approved Proactive framework and the Grid Reinforcement budget totaled just over \$112 million over six years. Staff highlights the over \$200 million reduction in spending as a meaningful way the existing IDP process has already reduced forecasted spending.

However, Staff does believe there is a significant gap between the IDP and cost recovery proceedings, specifically the general rate case. In multiple IDPs Staff has observed commenters presenting excellent analysis of Xcel's budget and proposed programs. However, those same arguments are absent in cost recovery proceedings. Throughout this briefing paper, Staff makes recommendations to better bridge the gap between the analysis presented in the IDP and how it is considered in cost recovery proceedings. Staff's goal is to have these recommendations mirror stakeholder positions but redirect them to the ultimate location where cost containment occurs: the rate case.

D. Process Recommendations

1. IDP Scheduling

Since Xcel Energy's first IDP in 2018, the number of additional requirements, attachments, and companion filings has grown substantially. This has resulted in multiple, overlapping comment periods and agenda meetings placing additional strain on intervenors, Staff, and the Commission. The Department recommended staggering IDP filings, which Staff concurs is necessary. The Department presented two options to stagger the filings, explained in greater detail in the Joint Briefing Papers. Staff recommends the option that would have Dakota Electric Association, Minnesota Power, and Otter Tail Power file their IDPs and any associated filings in even numbered years, while Xcel would remain on the existing schedule. Because there is no change to Xcel's IDP filing schedule, no decision options are necessary in the instant docket.

2. Standing IDP Improvement Workgroup

The Department also recommended using the distribution data workgroup from the prior IDP to determine if there were IDP filing points that could be eliminated (**Decision Option 3**). The Joint Briefing Papers cover this recommendation in more depth, but Staff's recommendation is to form a permanent "IDP Improvement Workgroup" that would follow the process used to update filing requirements from the prior IDP (**Decision Option 4**). Specific to Xcel, Staff also recommends referring topics to the Workgroup to develop or clarify filing requirements with **Decision Option 5**. The specific topics to refer to the workgroup are referenced in subsequent sections of the briefing paper.

IV. Xcel's 2025 IDP

A. Compliance with Commission Orders

The Department recommends the Commission accept Xcel's 2025 IDP with modifications.⁵

ELPC/CEF/VS claimed Xcel was not in compliance with the Commission's prior 2024 Order on Xcel's 2023 IDP. Specifically, ELPC/CEF/VS claimed Xcel did not comply with order requirements regarding Flexible Interconnection (Section I.1) and Planned Net Loading (Section I.2). In both cases, ELPC/CEF/VS recommended Xcel file a compliance filing by December 31, 2026 (**Decision Options 52 and 53**). If Xcel files these compliance filings, ELPC/CEF/VS recommends the Commission accept Xcel's 2025 IDP.⁶

Fresh Energy and the City of Minneapolis recommend the Commission accept Xcel Energy's 2025 IDP as in compliance with IDP reporting requirements.^{7,8}

Staff agrees that Xcel has fulfilled the Commission's filing requirements and prior order points to the standard the Commission has held the Company to in the past, contingent upon Xcel compliance filing on Planned Net Loading as recommended by ELPC/CEF/VS (**Decision Option 53**).

As explained in the Joint Briefing Papers, the Commission does not modify IDPs, therefore Staff recommends accepting Xcel's 2025 IDP and making additional decisions for future IDPs and future proceedings.

Decision Option 1 accepts the Company's IDP.

Decision Option 2 accepts the Company's IDP contingent on compliance filings.

B. Forecasting and Scenario Analysis

1. Forecasting Methodology and Inputs

Xcel's method of forecasting load and generation growth on the distribution system uses LoadSEER, a planning software. In the 2019 IDP the Commission certified Xcel's request to use an Advanced Planning Tool, which was realized as LoadSEER in its future IDPs.⁹ Xcel first used LoadSEER in its 2023 IDP. Prior to its use, Xcel did not perform a system wide spatially allocated forecast of load and generation on the distribution system and instead relied on the overall corporate forecast and discrete forecasts on an individual substation or feeder basis. LoadSEER integrates geospatial data, customer level data – including AMI, historical and forecasted

⁵ The Department 4-23-26 Reply Comments, p. 1.

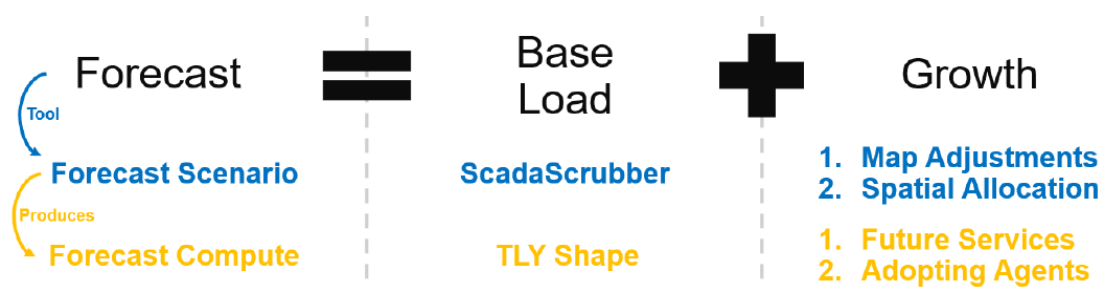
⁶ ELPC/CEF/VS 4-23-26 Reply Comment, p. 19.

⁷ Fresh Energy 4-23-26 Reply Comments, p. 9.

⁸ Minneapolis 2-26-26 Initial Comments, p. 2.

⁹ Docket 19-666, 7-23-20 PUC Commission Order, Order Point 14.

weather patterns, and distribution load flow application data to build a forecast. The following rough formula is Xcel's representation of how their forecast is assembled:¹⁰



ScadaScrubber is a LoadSEER tool that creates a Typical Load Year (TLY) shape which represent load on a circuit today under different weather scenarios, representing hourly loading on a feeder. These shapes can then be later updated for “growth” and “map” adjustments which represent new load and technology adoption respectively. Spatial Allocation is a process that takes high level forecasts and disaggregates it down to specific customers and locations. It does this by using future potential adoption points, shapes, and forecasts to simulate load growth across the system using a probabilistic model.

These shapes, adjustments, and spatial allocations are then fed into LoadSEER to create a scenario. The inputs that go into the LoadSEER scenario (base load + growth in the formula) are adjusted to provide the three scenarios Xcel chose to forecast. Xcel noted unlike in the previous IDP, where Xcel created alternative scenarios by applying percentage adjustments to the base case, each scenario now relies on a different set of assumptions regarding industry, policy, and customer trends. Xcel created three forecast scenarios as a basis for their load forecast and analyzed by LoadSEER.¹¹

1. **Base Case**
 - a. Reflects known and speculative growth
 - b. Serves as input to risk and mitigation creation for the budget plan
 - c. Used 2024 base case and updated with corporate forecast values in summer 2025
2. **High Adoption**
 - a. High growth patterns in solar and EV
 - b. Intended to test effects of high penetration of new load and DER
3. **Expanded Non-Residential**
 - a. Amplifies commercial and industrial business growth
 - b. Highlights trends in data center growth and industrial electrification

¹⁰ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 56 (PDF p. 91).

¹¹ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 57 (PDF p. 91).

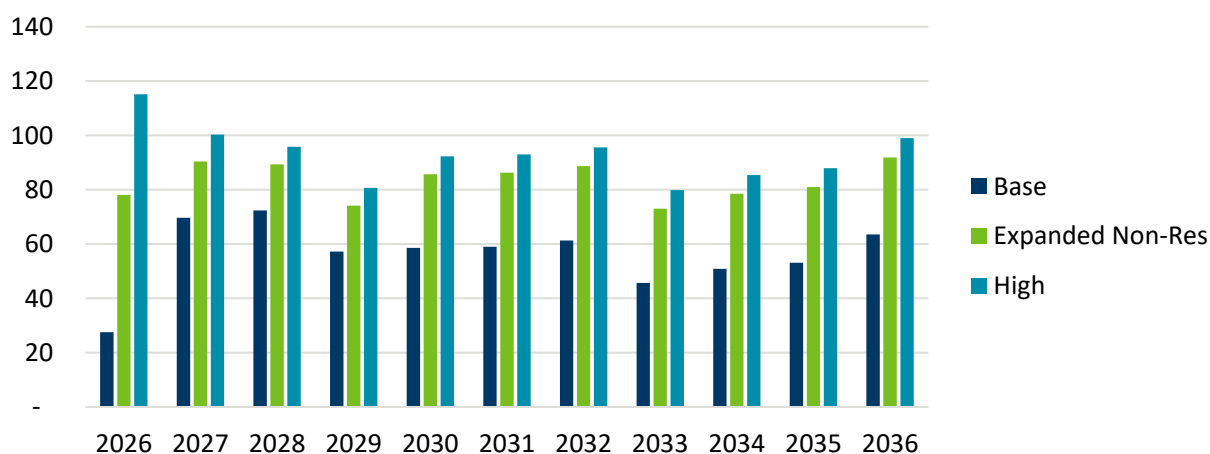
It should be noted up front that due to the timing of when these forecasts were created, these scenarios do not account for the sunseting of the Investment Tax Credits (ITC), EV rebates, and other home energy rebates in 2025 because of the H.R. 1 passing over the summer of 2025.¹²

The DER forecasts used in LoadSEER are derived from Xcel's corporate forecast, but their impacts are more targeted and location specific. LoadSEER is able incorporate those forecasts as part of the three created scenarios to better understand the impacts the distribution system may face under these various circumstances.¹³ Xcel did not include direct impacts from IRA tax credits in EV or solar forecasts beyond 2025, but information was in third-party data inputs.

The methodology for each forecast is as follows:

i. Load Forecast

Figure 2: Incremental Demand Growth (MW)¹⁴



The load forecast is calculated through LoadSEER which uses base load data obtained from ScadaScrubber and growth data which assumes adoption rates technologies in various feeders. More adjustments are then made and assumptions added for scenarios analysis.

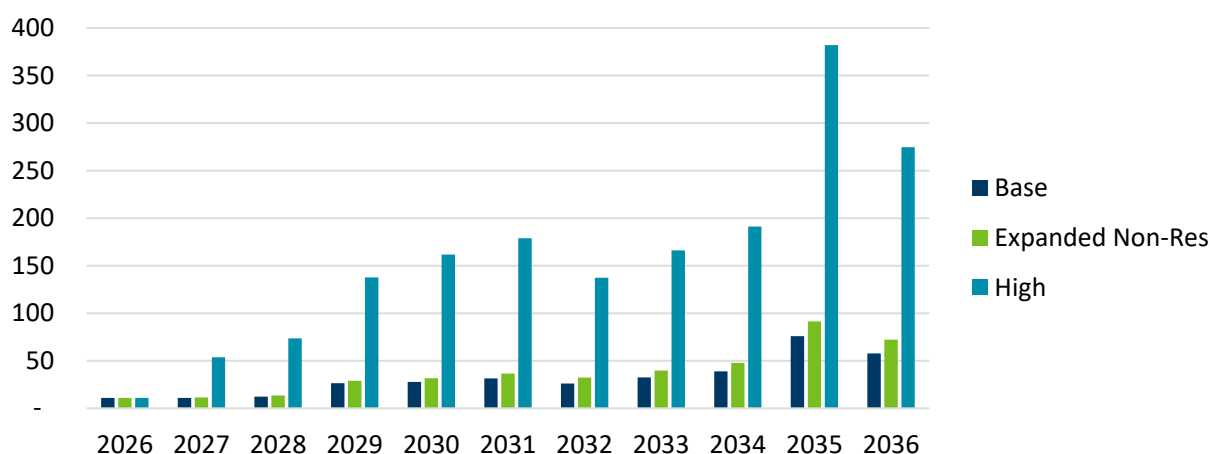
¹² Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 67 (PDF p. 102).

¹³ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 56 (PDF p. 91).

¹⁴ Xcel 2025 Integrated Distribution Plan, Chapter 1, Figure 1-21, p. 61 (PDF p. 97).

ii. Beneficial Electrification

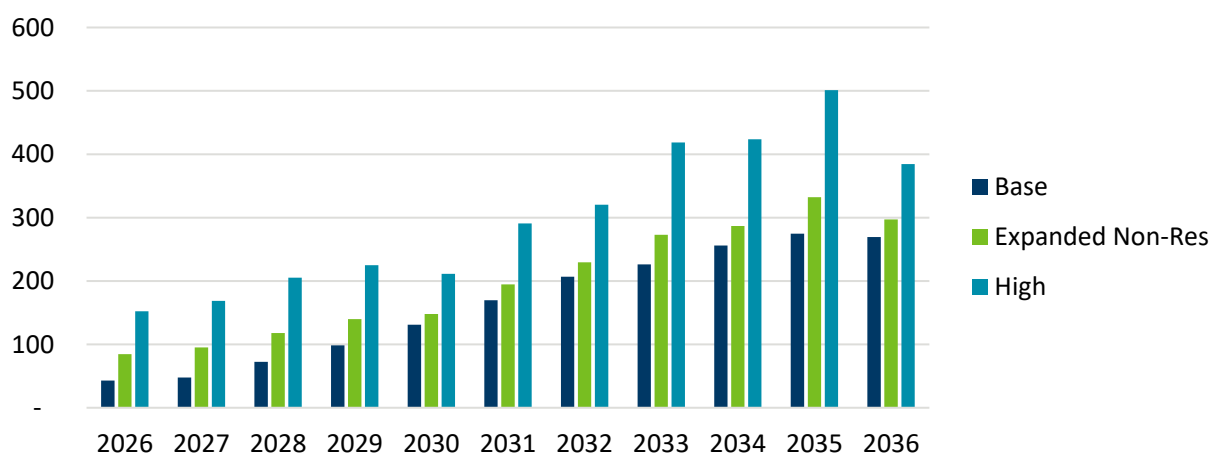
Figure 3: BE Incremental Demand Growth (MW)¹⁵



Scenarios include a Base Case based on the Company's corporate level July 2025 forecast, an Expanded Non-Residential scenario which increases load growth for those customers, and a High Adoption scenario that include greater uptake of Beneficial Electrification (BE) for residential customers. It does not include electric vehicle adoption, which is forecasted separately

i. Electric Vehicle Adoption

Figure 4: EV Annual Incremental Load Additions (MW)¹⁶



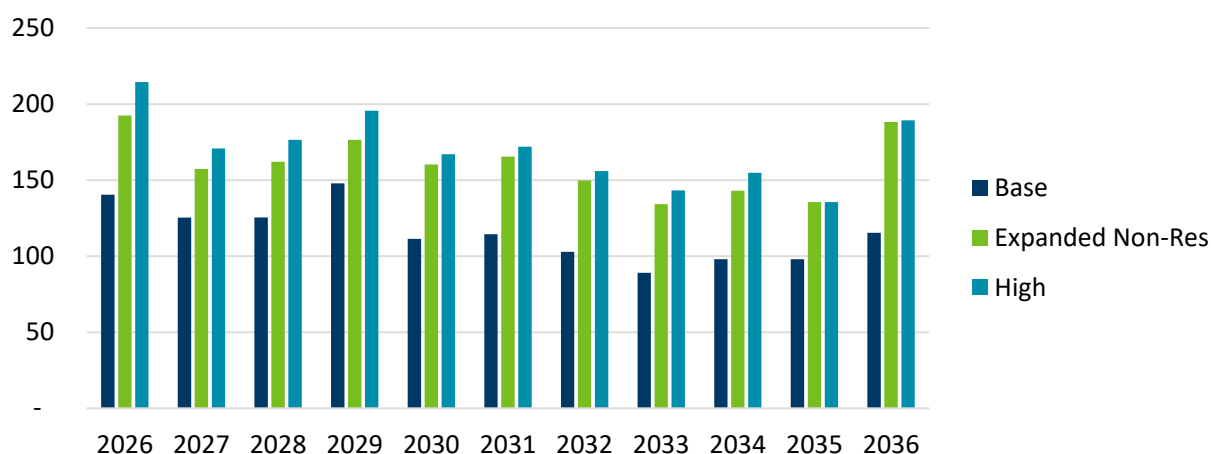
Xcel's EV forecast uses two modeling techniques: Bass Technology Diffusion and economic models. The economic models use total cost of ownership to estimate adoption. Xcel used their modeling to forecast adoption of Light Duty Vehicles (LDV), Medium Duty Vehicles (MDV), and High Duty Vehicles (HDV).

¹⁵ Xcel 2025 Integrated Distribution Plan, Chapter 1, Figure 1-23, p. 66 (PDF p. 101).

¹⁶ Xcel 2025 Integrated Distribution Plan, Chapter 1, Figure 1-22, p. 64 (PDF p. 99).

i. Energy Efficiency

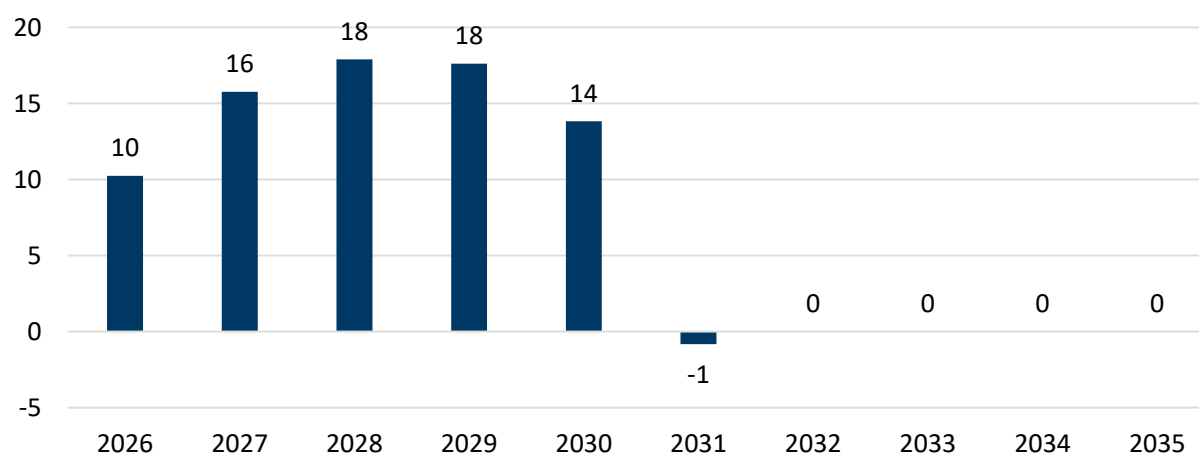
Figure 5: Energy Efficiency Annual Incremental Additions (MW)¹⁷



Xcel used assumptions from its 2024-2026 Energy Conservation and Optimization Triennial Plan as inputs for their three forecast scenarios and saw significant energy savings and demand reductions through the 2030s that leveled off after that period.¹⁸

i. Demand Response

Figure 6: Demand Response Annual Incremental Additions (MW)¹⁹



Xcel used the corporate energy forecast for demand response, which decreases load and when allocated to the distribution system its incorporated via impacts on corporate energy sales and demand forecast. Xcel stated that they expect expedited increases in their current resources of DR through their existing programs and anticipate further growth using AMI and DERMS.²⁰

¹⁷ Xcel 2025 Integrated Distribution Plan, Chapter 1, Figure 1-27, p. 71 (PDF p. 106).

¹⁸ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 46 (PDF p. 81).

¹⁹ Xcel 2025 Integrated Distribution Plan, Chapter 1, adapted from Figure 1-13, p. 48 (PDF p. 83).

²⁰ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 47 (PDF p. 82).

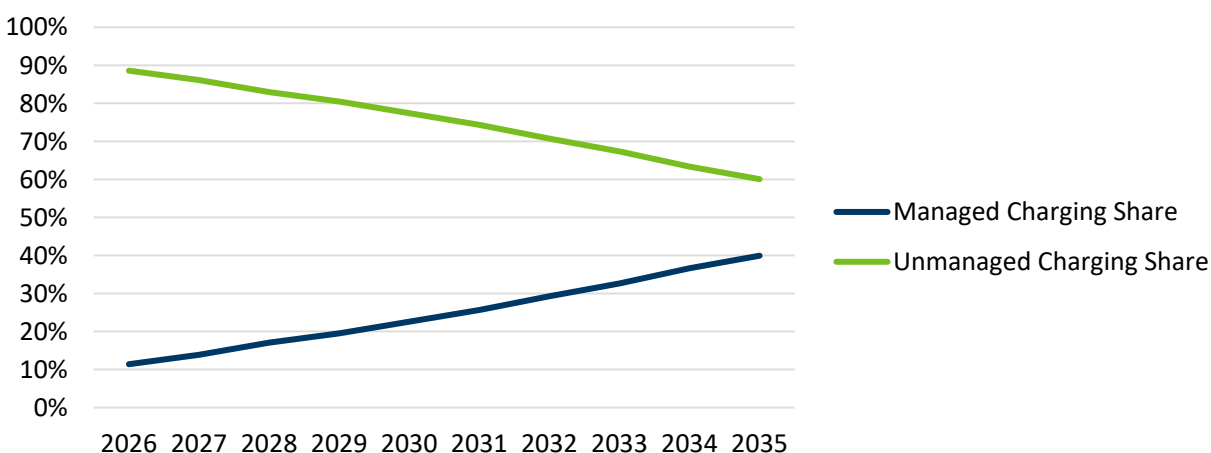
Fresh Energy commented that Xcel still does not include demand response in its substation or feeder forecasts and has made little progress on this issue. Fresh Energy pointed to identical paragraphs in the Company's 2023 and 2025 IDP describing its challenges incorporating demand response into its Distribution Planning. Fresh Energy expressed concern that Xcel would not be able to leverage cost effective DSM solutions to the rapid increase in capacity upgrades it anticipates over the coming years. Therefore, it recommended requiring Xcel to prioritize the integration of DSM into its distribution planning efforts.²¹

Xcel responded that while they agree that DSM and DR can be used to address localized needs, they were designed for bulk-system reliability. The Company added that their DR programs would require several days of advanced notice to be deployed and contrasted that to how distribution system conditions can change from hour to hour. Xcel stated to effectively and reliably use DSM and DR in the manner that requires full DERMS deployment and is a long-term goal that is several years away.

Fresh Energy disagreed that full implementation of DERMS is unnecessary before DSM can be integrated into distribution planning. Fresh Energy modified its recommendation to have Xcel submit a compliance filing in this docket within 6 months of the order that identifies non-DERMS changes the Company can make in the near term to better integrate DSM into distribution planning (**Decision Option 6**).²²

i. Load Flexibility Programs

Figure 7: Percent of Light Duty EVs on a Managed Charging Rate²³



Xcel focused solely on EV Managed Charging for load flexibility in this IDP and looked at a standalone EV Managed Charging forecast modeled on participants shifting away from peak hours to late evening and early morning.²⁴

²¹ Fresh Energy, 2-26-26 Initial Comments, pp. 8-10

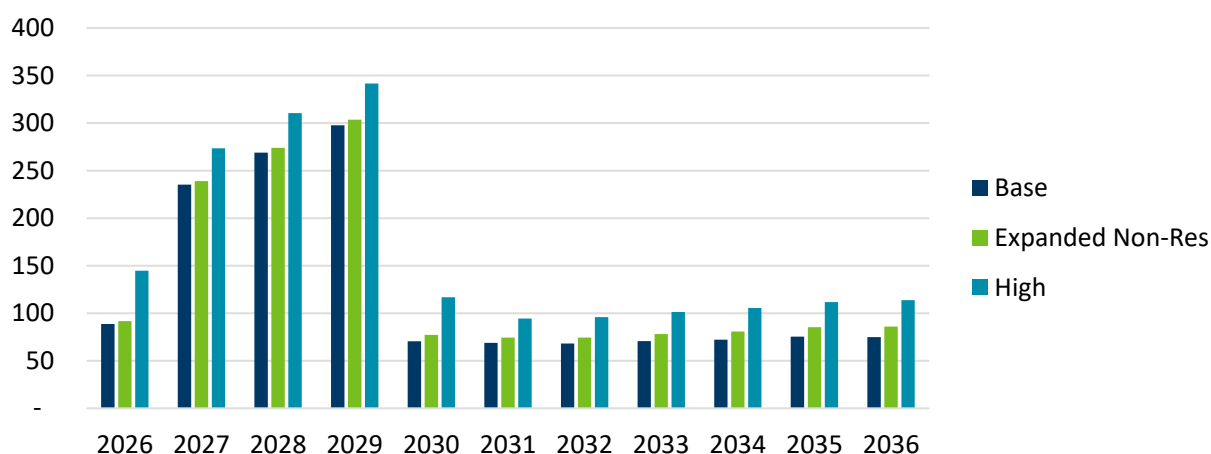
²² Fresh Energy, 4-23-26 Reply Comments, p. 5

²³ Xcel 2025 Integrated Distribution Plan, Chapter 1, Figure 1-14, p. 49 (PDF p. 84).

²⁴ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 49 (PDF p. 84).

ii. Distributed Solar PV

Figure 8: Distributed Solar Annual Incremental Additions (MW)²⁵



Xcel projected a steady uptake of distributed solar through 2029 with a leveling off beginning in 2030.

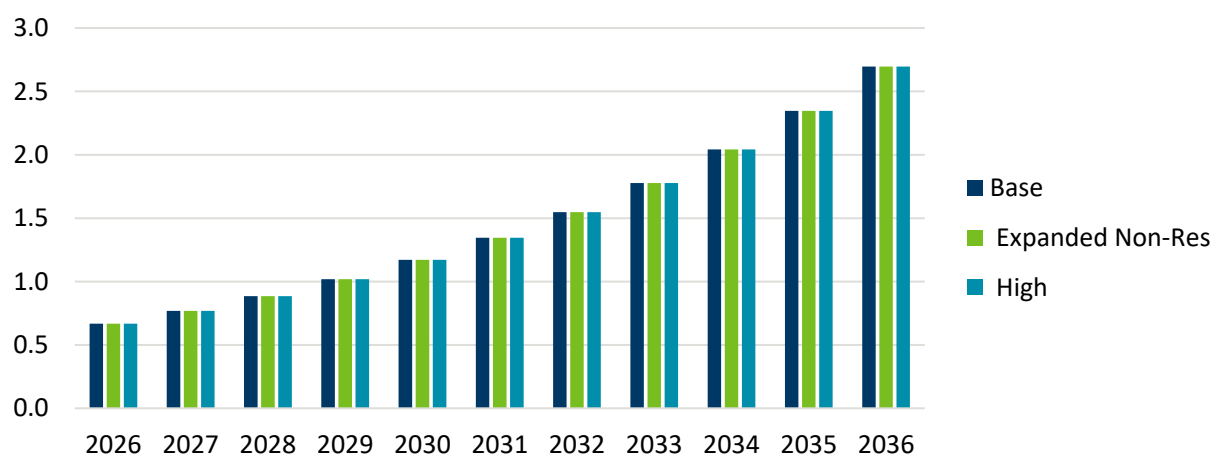
Solar*Rewards (S*R) and Solar*Rewards Community (CSG subscriptions) were estimated based on historical trends of funding levels and project conversion rates. Xcel assumed participants in CSG subscriptions see S*R as interchangeable.

The Company used the Bass Diffusion model using state specific, historical solar installed capacity through December 2024 and factor percentage accounting for customers unable to install solar. The Bass Diffusion models are used for technology adoption via an “S” shaped diffusion characteristic. The same model was used for CSGs using state data and using a high case that matches the legislative cap per year (100, 80, 60MW/year respectively).

²⁵ Xcel 2025 Integrated Distribution Plan, Chapter 1, pp. 67-69 (PDF pp. 102-104). Staff combination of Figures 1-24 and 1-25.

i. Distributed Energy Storage

Figure 9: Distributed Storage Annual Incremental Additions (MW)²⁶



The Company used a Bass Diffusion model for storage additions. The model coefficients are calibrated using state specific, historical storage systems installed through December 2024.

Xcel forecasted consistent growth throughout the planning period but noted that each scenario is sensitive to policy and technological changes as well as geopolitical risks. Xcel noted that this forecast did not include its Capacity*Connect proposal.²⁷

ii. Distributed Wind Generation

Xcel did not provide a model because of the Company's view that it will continue to have a very low impact on the distribution system.

2. Overall Forecast Results

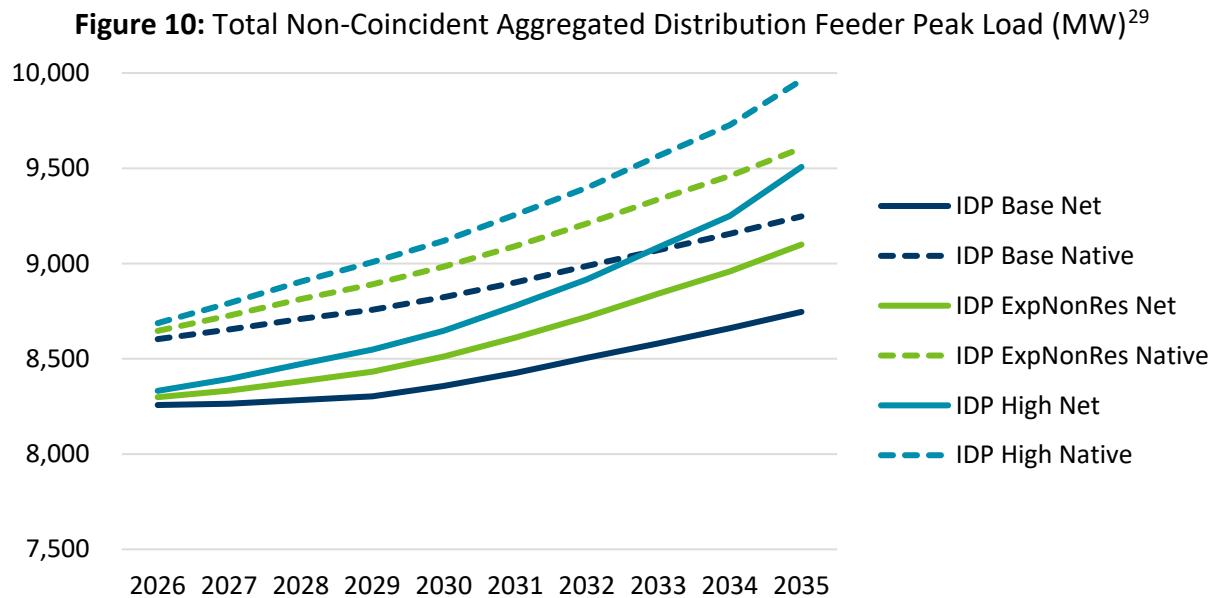
Aggregated Feeder Peak Load: Xcel's distribution forecast reflects aggregate non-coincident peak loads at the feeder level (the sum of the highest demand on each feeder regardless of when each peak occurs), unlike the Integrated Resource Plans, whose forecasts focus on coincident system peak (highest total demand across the system at a single point in time). This results in a distribution system that could accommodate more load than the overall system as each feeder must be planned to its own peak, regardless of when the peak occurs in relation to the system peak.

Figure 10 illustrates growing native load, which excludes contributions from DER generation.²⁸ Native load is the total amount of load on a system without the reducing effects of DERs. Net load is the native load minus the impacts of DERs.

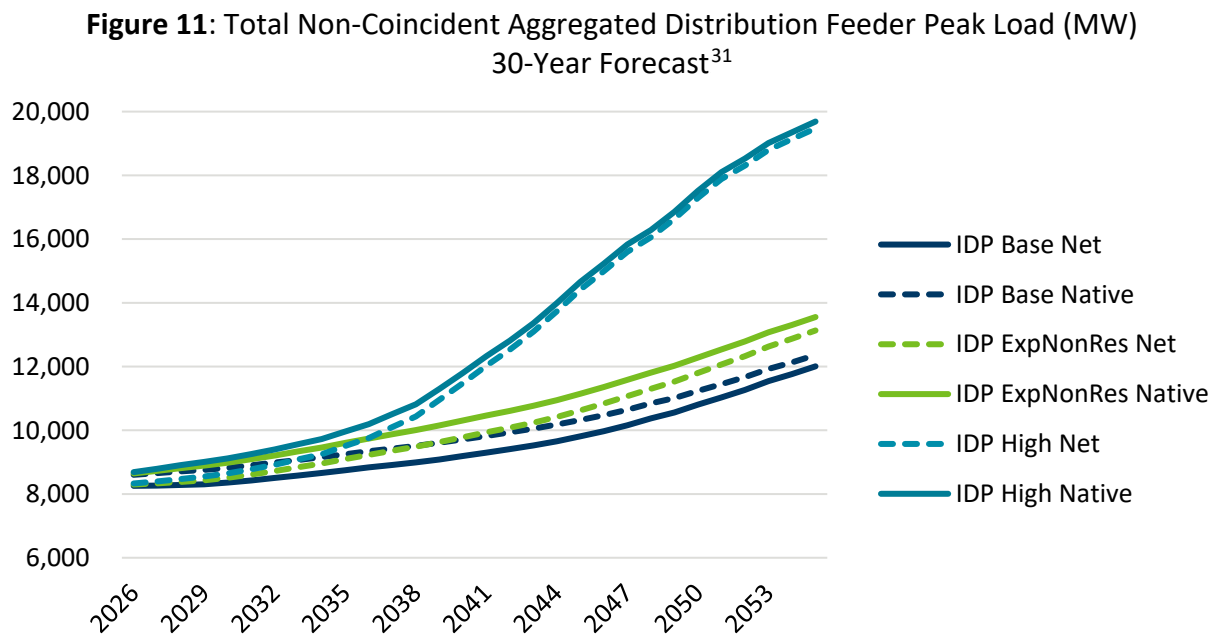
²⁶ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 70 (PDF p. 105). Staff combination of Figures 1-24 and 1-26.

²⁷ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 44 (PDF p. 79).

²⁸ Xcel 2025 Integrated Distribution Plan, p. 73 (PDF p. 108).



The aggregate total of non-coincident feeder peak demands on the distribution system is expected to increase from around 8.5 GW to over 9.30-10 GW by 2035. This includes the net and native loads for each scenario. Xcel expanded the forecast to a 30-year timeline and indicated more rapid rate of growth beyond the ten-year forecast due to their expected EV adoption and BE growth.³⁰



²⁹

³⁰ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 74 (PDF p. 108).

³¹

3. LoadSEER Comparison and Accuracy

Xcel provided the actual Aggregated Distribution Feeder Peak Load to the forecasted values in Table 2.

Table 2: Comparison of 2023 IDP Forecast to Actuals
Aggregated Distribution Feeder Peak Load – MN (MW)³²

	2023 IDP Forecast			Actual
	Low	Medium	High	
2023	8,702	8,708	8,715	8205
2024	8,806	8,819	8,837	7996

Xcel explained that these discrepancies can happen for the following reasons:³³

- Weather impacts
- New customers not coming online in the year expected
- New customer loads coming in less than the forecasted peak demand value
- Load switching
- Changes to aggregate distribution feeder peaks

Xcel stated that LoadSEER “does not currently have metrics or analytical capabilities related to evaluating the accuracy of its forecasts” but that there have been “substantial work done to improve the granularity of the system-level forecast provided as an input to LoadSEER” which the Company stated helped develop more detailed and accurate distribution modeling within LoadSEER.³⁴

The Department commented that Xcel’s LoadSEER forecasts seem to be biased towards estimating more capacity than actual data.³⁵ This may lead the Company to build more capacity than necessary. The Department provides its full analysis in its comments on Xcel’s Proactive Upgrade Proposal however Staff summarizes relevant portions here.

The Department explained that because LoadSEER uses Xcel’s system-wide forecast, if the system-wide forecast is inaccurate, the resulting spatial allocation will also be inaccurate. The Department compared the past 10 years of Xcel’s system wide forecasts to actual energy sales and found that in years six through ten Xcel has historically overestimated energy sales between 5 and 13 percent, with overestimates increasing in the out-years of the forecast.³⁶ The Department also provided Xcel’s initial analysis of its 2023 LoadSEER forecast accuracy, where the 2023 IDP Low Forecast was 6.1% higher than the actual and the 2024 forecast was 10.1% higher.³⁷ The Department contrasted these higher values in the near term forecast with

³² Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 77 (PDF p. 112).

³³ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 76 (PDF p. 111).

³⁴ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 78 (PDF p. 113).

³⁵ Department 2-27-26 Initial Comments, pp. 38-39.

³⁶ Department, 1-28-26 Initial Comments, p. 5-6

³⁷ Department, 1-28-26 Initial Comments, p. 6

the lower values from the corporate forecast. In particular, the Department expressed concern that because use of LoadSEER is relatively new, there is not sufficient data to assess the forecast validity, which may grow exponentially in years 6-10 of the forecast.³⁸

The Department noted that the 2023 vintage scenarios are different from the 2025 vintage scenarios, and therefore Xcel should provide an analysis of each forecast vintage. The Department recommended that the Commission create a new IDP filing requirement to provide a comparison of forecast accuracy for each vintage and scenario (IDP Low, Medium, High) in Xcel's LoadSEER forecasts compared to actuals.

ELPC/CEF/VS also noted that the LoadSEER forecast for 2023-2024 was off by 500 MW (6% over) and 800 MW in 2024 (10% over).³⁹ They reasoned that such discrepancies could result in larger errors on specific substations which may trigger unnecessary proactive investments.

Xcel did not support the Department's request for Xcel to reconcile the forecasted values in the Department's initial comments with historical peak loads trends. The Company reasoned that yearly fluctuations in peaks are normal due to various factors such as weather, economics trends, and distributed solar generation and that the historical values in the Department's comments are not reliable since data for 2020-2021 is incomplete due to the introduction of LoadSEER. Xcel also emphasized that the IDP is a forward-looking tool not meant to match historical peaks and that it is planning forecast, "designed not to predict the most likely peak load for the upcoming year, but to identify how high peak demand could reasonably be under extreme but plausible conditions."⁴⁰

In response, the Department stated that the Company makes some valid points but ultimately reiterated that since LoadSEER is new and a "black box" used for budgetary decisions the accuracy of its forecasts are important to analyze.⁴¹ The Department claimed that what the Company has provided in its IDP is not sufficient to determine the accuracy of LoadSEER. In reply comments, ELPC/CEF/VS agreed with the Department and stated that Xcel should find it worthwhile to invest resources into confirming LoadSEER's accuracy.⁴²

The Department modified its recommendation to the following:

The Department recommends the Commission create a new IDP filing requirement to provide a comparison of forecast accuracy for the forecast scenario or scenarios Xcel uses for budgeting in Xcel's LoadSEER forecasts compared to actuals. Forecast accuracy should adjust model parameters to actual observed conditions to determine the accuracy of the forecast. **(Decision Option 7)**

³⁸ Department, 1-28-26 Initial Comments, p. 8

³⁹ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 24-25.

⁴⁰ Xcel 3-19-2026 Reply Comments, Attachment A, p. 3 (PDF p. 11).

⁴¹ The Department 4-23-26 Reply Comments, pp. 31-32.

⁴² ELPC/CEF/VS 4-23-26 Reply Comments, p. 18.

4. *Community-Based Climate Goals*

Xcel noted that several communities have begun incorporating EV adoption goals as well as Climate Action Plans. The Company sent a survey via email to 415 cities, townships, and counties to determine if those entities had any specific plans that Xcel could plan around. Xcel stated they received 107 responses, of which 32 indicated some clean-energy plan or goal.⁴³

Xcel noted that obtaining sufficient and specific data from these responses was difficult and that the plans or goals themselves would be challenging to convey and input LoadSEER. The Company stated that it is supportive of its communities' goals and encourages outreach to relations managers so that the Company may help in their objectives.

Minneapolis appreciated Xcel's efforts to consider and incorporate community-based climate goals but advocated that since it is the largest city in Xcel's Minnesota service territory, Minneapolis believed that incorporating a "Minneapolis electrification scenario" in future planning would be helpful to understand more localized grid congestion. The City noted that it has implemented or plans to implement various programs that impact the distribution system.⁴⁴

Xcel did not support the City of Minneapolis' recommendation that Xcel incorporate a "Minneapolis electrification scenario" into future planning to reflect several city-specific initiatives.⁴⁵ Xcel indicated that the IDP must remain neutral in terms of jurisdiction and across service areas, and that "modeling unique city-level assumptions would introduce unverifiable load forecasts, create planning inconsistencies, and raise equity concerns across other municipalities."⁴⁶

In reply comments, Minneapolis reiterated its support for incorporating locally informed electrification scenarios into integrated distribution planning. The City argued that utility planning should reflect local electrification initiatives and development patterns and proposed piloting a local electrification overlay using community-specific data to improve forecasting and identify future capacity constraints. Minneapolis stated that such analysis is consistent with existing IDP requirements, could be supported by existing planning tools, and has precedent in other Minnesota utility planning efforts. The City offered to support a pilot through data sharing and coordination and suggested that additional communities could participate to evaluate broader applicability across Xcel's service territory (**Decision Option 8**).

5. *Distribution System Upgrades*

Minn. Stat. [216B.2425 Subd. 9](#) requires Xcel to forecast the estimated required distribution system upgrades to accommodate distributed generation.

⁴³ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 80 (PDF p. 115).

⁴⁴ Minneapolis 2-26-26 Initial Comments, p. 2.

⁴⁵ Xcel 3-19-26 Reply Comments, Attachment A, pp. 36-67 (PDF pp. 44-45).

⁴⁶ Xcel 3-19-26 Reply Comments, Attachment A, pp. 36-67 (PDF pp. 44-45).

To estimate the upgrades necessary to accommodate distributed generation, Xcel used existing interconnection queues on the distribution system as well as LoadSEER forecast data to give a feeder level, year-by-year forecast of PV generation allocated to the distribution system.⁴⁷ The Company used the IDP Base Case scenario of the solar PV adoption forecast, which includes Residential PV, Commercial PV (including resources procured for the Distributed Solar Energy Standard), and Community Solar Gardens (CSGs).

In order to determine when an upgrade is needed, Xcel used the Technical Planning Standard (TPS)⁴⁸ and Hosting Capacity Analysis (HCA) report as different scenario thresholds.⁴⁹ Xcel noted that the HCA is more restrictive, and therefore more expensive to resolve, as it analyzes more than just capacity (voltage, protections, coordination, etc.).

When the TPS or a limitation on the HCA is breached, Xcel used a marginal cost of capacity of \$800/kW as a proxy for the required upgrade costs which they claim is consistent with the Capacity*Connect proceeding which used DSM modeling in Minnesota and the Company's Colorado Aggregator VPP settlement agreement. Xcel categorized existing costs as costs for upgrades where the TPS or HCA already requires an upgrade for existing installed generation or to accommodate projects in the interconnection queue.

Xcel quantified and summarized the forecasted cost for each scenario over the 30-year forecast period in Table 3.

Table 3: Summary of Upgrade Cost Components for Each Cost Scenario (\$ Millions)⁵⁰

Cost Scenario	Cost to Resolve Existing Constraint	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

Xcel provided the forecast on a year-by-year basis as well:⁵¹

⁴⁷ Xcel 2025 Integrated Distribution Plan, Chapter 10, p. 2 (PDF p. 404).

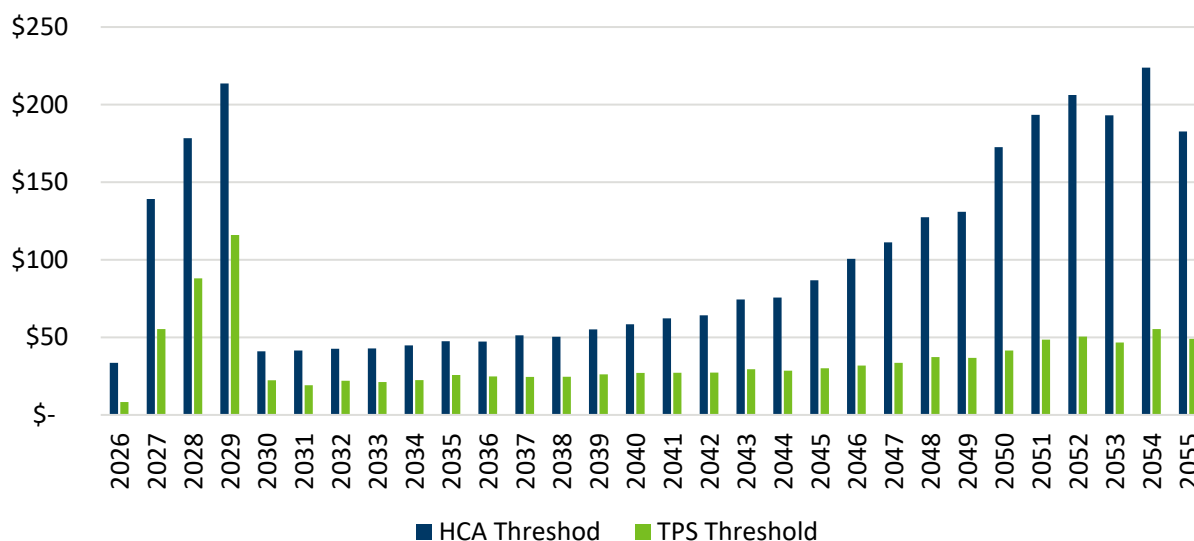
⁴⁸ TPS refers to 80% of the continuous rating plus the daytime minimum load to determine the maximum allowable DER penetration on a feeder or substation transformer before upgrades are required. TPS is used to calculate the optimal mix of solar PV and energy storage needed to address the remaining risk while maximizing the incremental net impact (net benefits minus net costs).⁴⁸

⁴⁹ Xcel 2025 Integrated Distribution Plan, Chapter 10, p. 4 (PDF p. 406).

⁵⁰ Xcel 2025 Integrated Distribution Plan, Chapter 10, Table 10-1, p. 5 (PDF p. 407).

⁵¹ Xcel 2025 Integrated Distribution Plan, Chapter 10, p. 6 (PDF p. 407).

Figure 12: Forecast of Upgrade Costs 2026-2055, for TPS and HCA Cost Scenarios⁵²



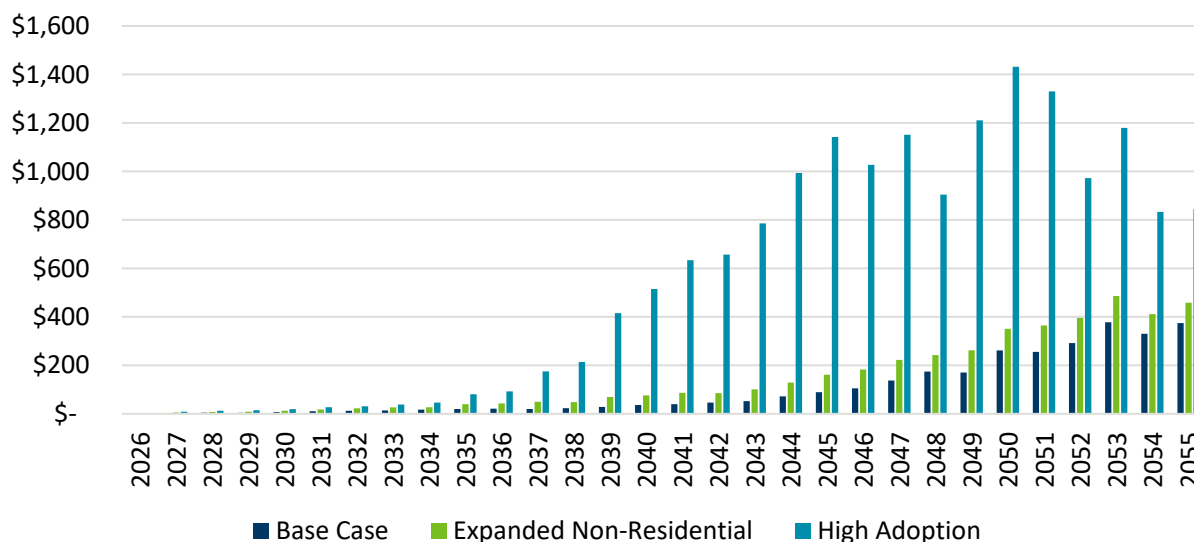
Xcel explained that smart inverters, ADMS, AMI, and DERMS will all help reduce the need for future upgrades or reduce their costs.⁵³

Xcel also forecasted the costs of the distribution upgrades to accommodate forecasted load over a 30-year period and specifically targeting upgrades necessary to resolve N-0 violations to within 100% of rated capacity. Xcel forecasted the following for each of the LoadSEER scenarios using \$800/kW for marginal capacity:

- Base Case: \$3.0 billion
- High Adoption: \$16.4 billion
- Expanded Non-Residential: \$4.4 billion

⁵² Xcel 2025 Integrated Distribution Plan, Chapter 10, Figure 10-2, p. 6 (PDF p. 408).

⁵³ Xcel 2025 Integrated Distribution Plan, Chapter 10, pp. 6-8 (PDF p.407-410).

Figure 13: Incremental Results for Potential Capacity Upgrade Costs Related to Scenarios⁵⁴

Importantly, some upgrades for load will accommodate additional distributed generation, while some upgrades for generation will also accommodate load. In other words, the estimated upgrades will overlap and offset each other. There is also the potential to strategically site generation and load together to avoid upgrades all together.

6. Staff Analysis

Staff is glad to see continued progress in Xcel's forecasting ability and methodology using LoadSEER. Each iteration has become more data driven with increased capacity to include more trends, policies, and technologies. Staff is encouraged to hear the Company plans to continue to expand its use of LoadSEER with increased utilization of AMI and potential DERMS functions.

Staff believes that there is sound rationale behind each of Xcel's three scenarios. However, this IDP clearly shows a missing scenario – a scenario where growth is more conservative than the base case. H.R.1⁵⁵ accelerated the termination date of the residential Investment Tax Credit as well as tax credits for EVs and charging stations. This, or anything close to this type of disruption to the base case was not added to any scenario. Currently, Staff now finds it difficult to determine how similar or dissimilar the forecasts may now be given such a great policy change. While it is easy to look at the past in hindsight, Staff believes it may have been overly optimistic for the Company to not include any conservative scenarios given how national policy-dependent much of the DER growth has been over the last 8-12 years as well as how mercurial those policies have been over that same timeframe. Staff suggests that in future IDPs the Company contemplate and forecast scenarios that are more conservative than the base case scenario. **Decision Option 5.b** would direct the IDP Improvement Workgroup to modify the filing requirements to better define various forecast scenarios.

⁵⁴ Xcel 2025 Integrated Distribution Plan, Chapter 10, Figure 10-3, p. 12 (PDF p. 414).

⁵⁵ Also known as the "One Big Beautiful Bill Act"

Fresh Energy requested to have Xcel file a compliance to identify non-DERMS changes the Company can include in the near term to better integrate DSM into distribution planning within six months of the order. Staff believes that there could be some benefit in gaining insight from the information this compliance order would provide although Xcel appears steadfast in its understanding that DERMS is a requirement for this DSM use case. While Staff agrees that using DSM and DR to help facilitate localized needs, Staff does not see this as a critical, near-term issue that requires an interim compliance filing. If the Commission is interested in this information, Staff recommends modifying **Decision Option 6** to require the information with the next IDP.

The Department broadly requested more evaluation and analysis on LoadSEER's accuracy or deviation from prior forecasts, finding what Xcel provided in its IDP to be lacking. Xcel provided possible factors that might cause their forecast to deviate from actuals. Staff agrees that there could be some increased vision into LoadSEER's forecasts and applying actual data and adjusting model parameters to run through LoadSEER again to see how it forecasts against actual the actual data. Staff agrees with Xcel that these forecasts are for planning purposes and are not meant to predict the most likely peak load but how high peak demand could be under extreme but plausible conditions. Staff would not see this as a judgement on Xcel's forecast accuracy but as potential opportunity to see if there are any systemic alterations to any assumptions that can be made to better LoadSEER's ability. That said, Staff does believe it is worthwhile to track Xcel's actual peak load data in some format, and to have the Company include a narrative on variances from the forecast. Staff therefore recommends **Decision Option 5.a**.

Staff understands the City's reasoning for wanting to establish a pilot with Xcel regarding integrating their various city plans and programs into the Company's forecasting scenarios. However, the Company is correct in stating that the IDP is service-area-wide and that specific inputs from municipalities and their plans and goals remain difficult to verify. Xcel stated that the City could engage in the Proactive Distribution Grid Upgrades (PDGU) Framework stakeholder process. The City could provide information on their programs in this space to help identify whether targeted upgrades are warranted. Otherwise, the Company seems open to dialogue with the City and Staff believes direct communication and exchange of information may be a better first step than a pilot.

On forecasting distribution system upgrades costs, Staff notes that the forecasts have some assumptions that may increase the total estimate costs. First, Staff is not certain that \$800/kW of marginal capacity is an accurate or realistic value. The Company stated that it used both DSM modeling and its VPP settlement agreement in Colorado to derive that number. Staff questions this methodology as it does not appear close to market value of capacity seen in other interconnection proceedings such as the Distribution System Reactive Upgrade Process (DSRUP),⁵⁶ which is a market-driven cost sharing process for large distribution upgrades. In the stakeholder discussions that helped lead to a draft of the standards, some developers anecdotally stated that more than \$200-300/kW would price them out of interconnecting

⁵⁶ Docket E-002,015,017/CI-24-288; Tariff filings from Xcel are due July 20th, 2026

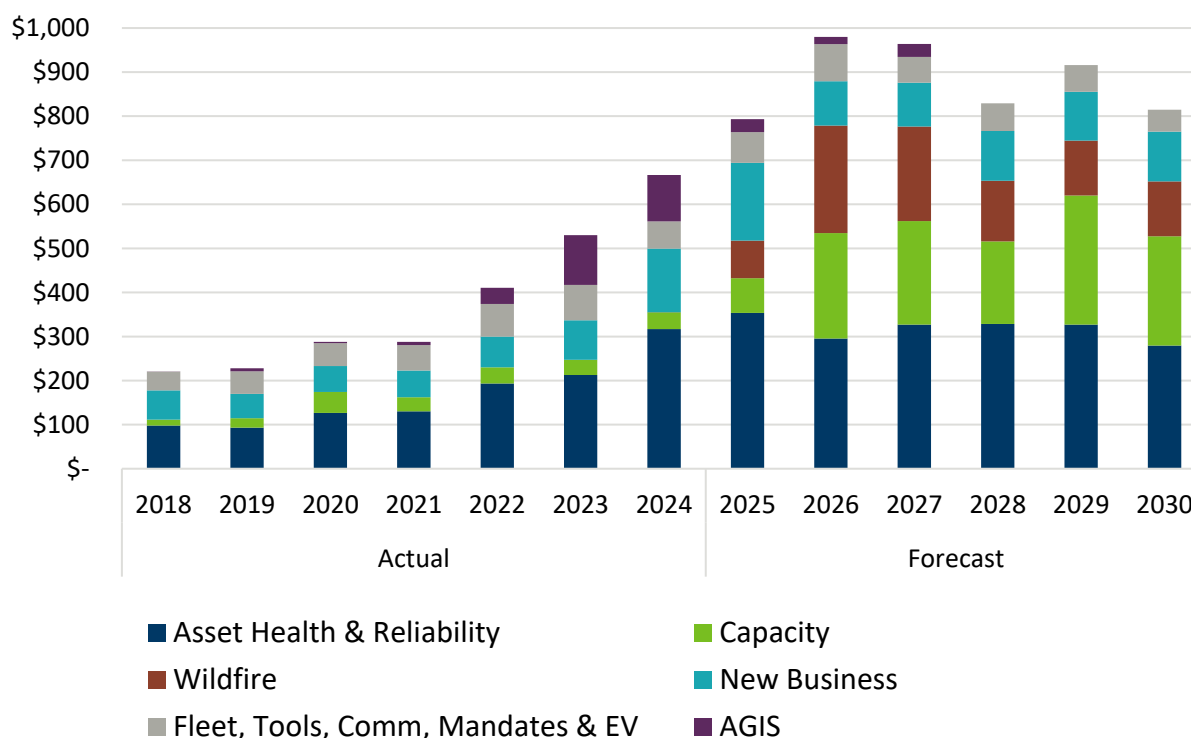
under a cost sharing program, while others stated up to \$600/kW may be economical. Therefore, it is unclear whether solar developers would pay \$800/kW to interconnect, indicating it may not be an appropriate value to estimate the cost of distribution upgrades. Staff suggests that in its next IDP, Xcel incorporate actual upgrade cost data from recent years to forecast the total costs. Finally, under the new cost-sharing programs approved under the Proactive Distribution Upgrade Framework and the DSRUP, both large, distributed generation and large load will help pay for the cost of some of these forecasted upgrades, alleviating ratepayer impacts.

C. Budget

1. Budget Overview

Xcel prepares a five-year budget forecast every year for its distribution spending.⁵⁷ The Company stated that only the first year of each forecast is “locked in,” and future years are continuously refined based on actual expenditures and grid conditions. Figure 14 depicts the Company’s historic and forecasted capital budget for 2018-2030 using Xcel’s internal budget categories.

Figure 14: Actual and Budgeted Distribution Capital Expenditures by Xcel Capital Budget Category (\$M)⁵⁸



⁵⁷ Xcel Integrated Distribution Plan, Chapter 6, p. 2 (PDF p. 250).

⁵⁸ Xcel Integrated Distribution Plan, Chapter 6, pp. 9-10 (PDF pp. 257-258), Figures 6-2 and 6-3; Staff adaptation

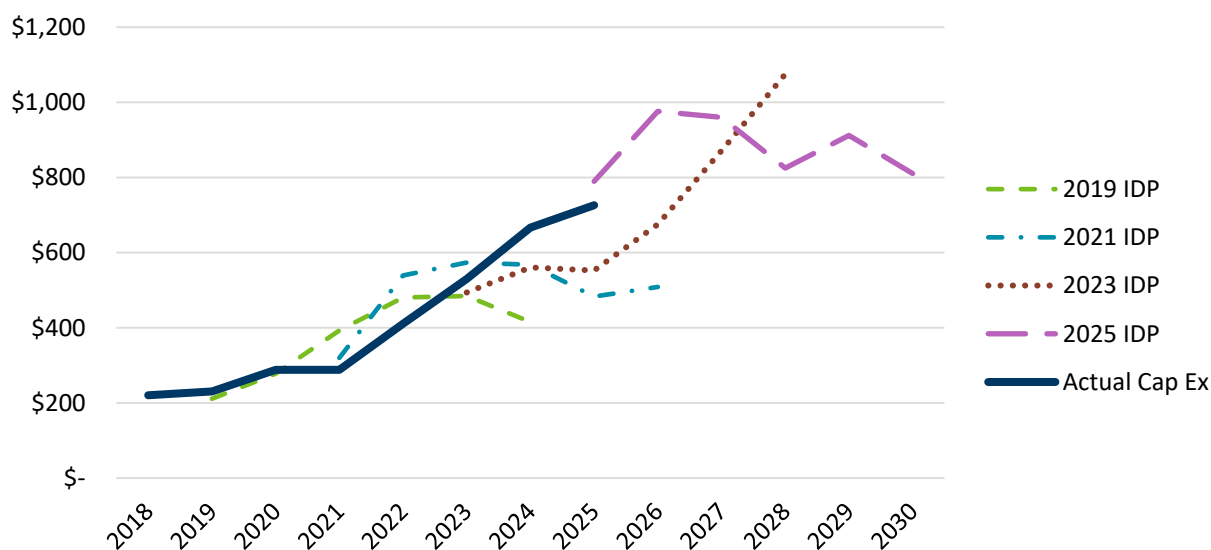
Staff notes that Xcel categorizes its internal budget categories differently from the standard IDP budget categories, and Xcel provided a comparison on Chapter 6, p. 3 of its IDP (PDF p. 251). The Joint Briefing Papers contain a cross-utility spending comparison using IDP budget categories.

The Department conducted analysis on Xcel's actual spending versus its forecasted budgets between 2018-2030.⁵⁹ The Department noted that the largest increases come from three expenditure categories: Asset Health & Reliability, Capacity, and Wildfire Mitigation.⁶⁰ Discussions on these specific topics can be found in Sections D.1 (Asset Health and Reliability Budget), F.2 (Capacity Planning Standards), and E (Wildfire Mitigation).

i. Staff Analysis

Staff performed a comparison of Xcel's forecasted IDP budget to actual expenditures to determine where the two diverged, depicted in Figure 15. When looking at the overall distribution budget, Xcel's actual expenditures compared to the forecasted budget were fairly accurate, especially for the first few years of the forecast.

Figure 15: Forecasted vs Actual Distribution Capital Expenditures by IDP Vintage (\$M)⁶¹



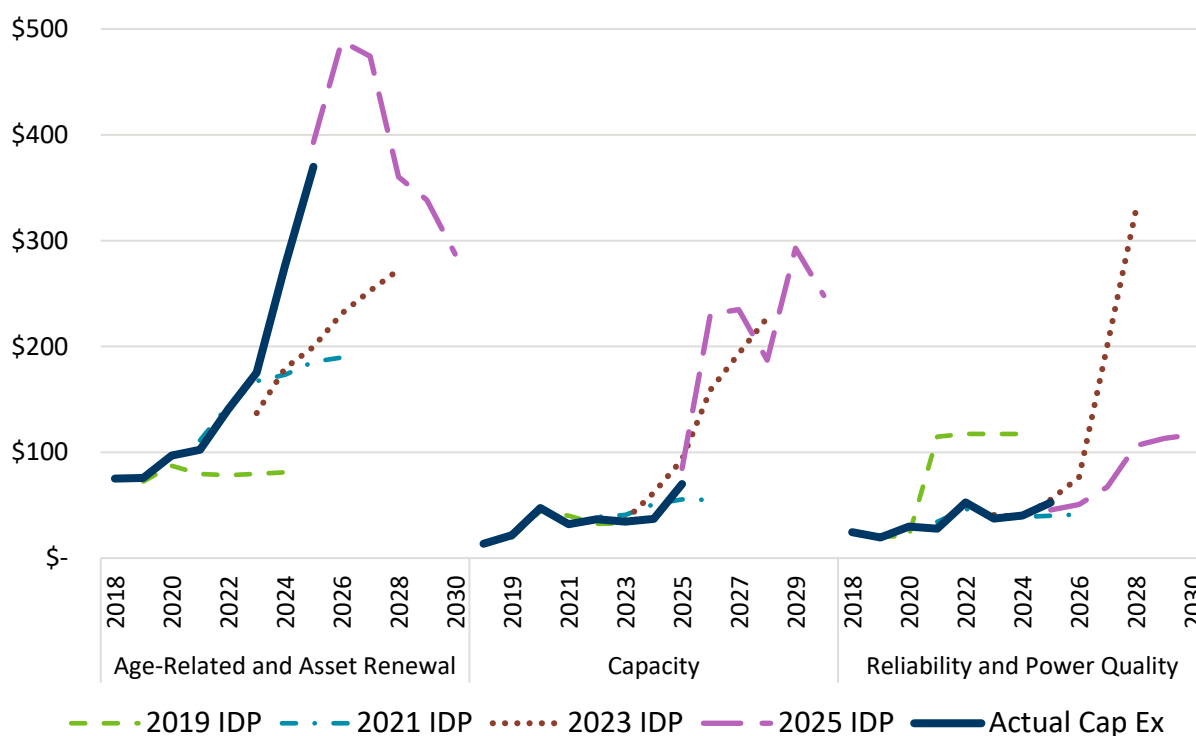
When Staff compared the different categories of the distribution budget, a more complex picture emerged. Specifically, when looking at the three largest budget categories, Age Related and Asset Renewal, Capacity, and Reliability and Power Quality, the forecasted amounts and actual spend diverged from each other.

⁵⁹ Department 2-27-26 Initial Comments, Trade Secret Version, pp. 27-29 (PDF pp. 35-37).

⁶⁰ Department Initial Comments, p. 27 (PDF p. 35).

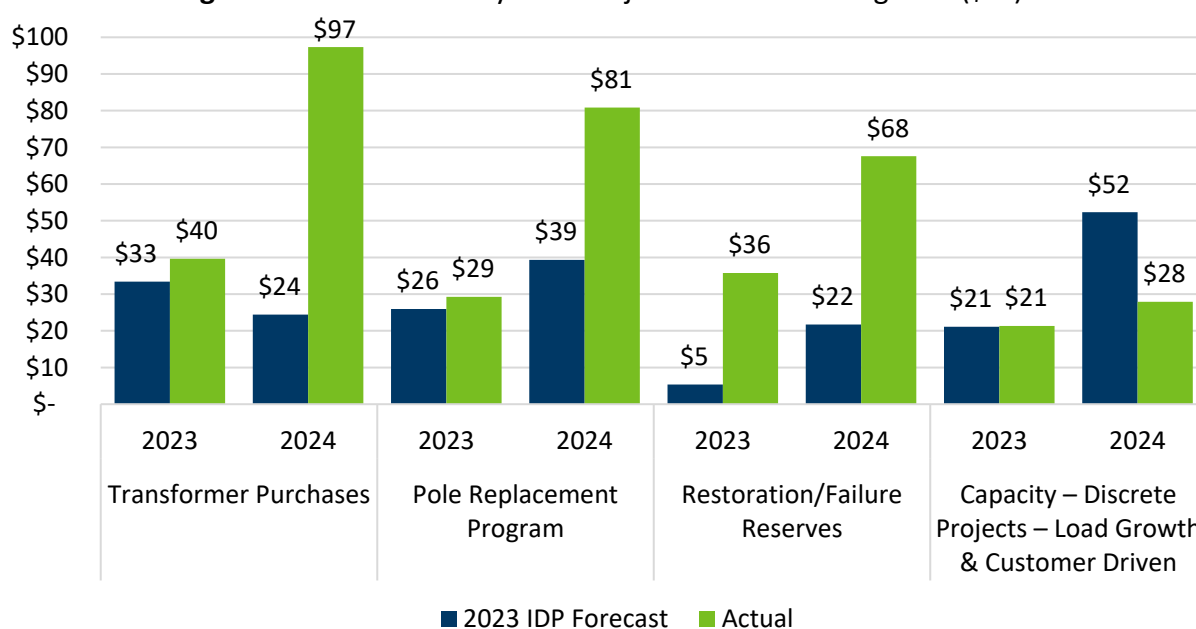
⁶¹ Created with budget numbers included in Xcel's 2019-2025 IDPs.

Figure 16: Forecasted vs Actual Distribution Capital Expenditures by IDP Vintage, Select Categories (\$M)⁶²



A closer look at four specific programs for 2023 and 2024 depicts how even one year into a forecast, actual spend can vary drastically (Figure 17).

Figure 17: Variance Analysis of Major Distribution Programs (\$M)⁶³



⁶² Created with budget numbers included in Xcel's 2019-2025 IDPs.

⁶³ Created based on Xcel response to PUC IR 5.

To better understand the drivers of budget changes, Staff recommends supplementing and updating some of the budgetary IDP filing requirements. First, Staff recommends establishing a filing requirement that provides a better breakdown of specific distribution program spending similar to the information requested in Staff IR 5. Second, Staff recommends requiring a variance analysis for programs that either exceed or underspend their forecasted amount by some percentage. Staff also recommends tracking actual spending for large, discrete capital projects. Currently Xcel provides a forecast of individual projects in Attachment H, but there is no follow-up information once the projects are built. Finally, when reviewing Xcel's 2024 rate case in conjunction with its 2025 IDP, Staff noticed the Company includes both capital expenditures and capital additions in the rate case, while the IDP only includes capital expenditures. Having more information around capital additions and how that compares to capital expenditures would clarify spending patterns.

Instead of proposing language for new filing requirements here, Staff recommends referring the topics to the IDP improvement workgroup so stakeholders and Xcel can work together to get the necessary information as efficiently as possible (**Decision Option 5.d-g**). Staff believes most of the information likely already exists, so it should be relatively straightforward to determine the best way to include it in future IDP filings.

2. Cost Benefit Analysis

The Commission's September 24, 2024 Order required Xcel to:

1. Include a discussion of the results of stakeholder conversations about ways to conduct program-level cost-benefit analyses for relevant discretionary distribution expenditures.
2. Explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.⁶⁴

Xcel presented in its petition cost-benefit analyses (CBAs) for two discretionary-level programs investments after conducting several CBA Workshops to gather stakeholder input:^{65,66}

1. End of Life Replacement Breakers⁶⁷
2. Grid Reinforcement Program⁶⁸

To calculate the CBAs, Xcel compared five years of historical spending of the programs to the anticipated benefits of proactively investing in the distribution system.⁶⁹ To estimate financial impact avoided, Xcel assumed certain customer minutes out (CMOs) from equipment and overload outages, as well as labor costs that could escalate should issues emerge if the Company did not invest in system upgrades.

⁶⁴ 2023-2025 IDP Order, Ordering Paragraphs 11-12.

⁶⁵ [Cost Benefit Analysis Workshop Invitation \(March 18, 2025\)](#)

⁶⁶ Xcel Integrated Distribution Plan, Chapter 6, pp. 22-24 (PDF pp. 270-272).

⁶⁷ Xcel Integrated Distribution Plan, [Attachment M \(October 31, 2025\)](#) (Trade Secret)

⁶⁸ Xcel Integrated Distribution Plan, [Attachment N \(October 31, 2025\)](#) (Trade Secret)

⁶⁹ Xcel Integrated Distribution Plan, Chapter 6, p. 22-24 (PDF pp. 270-272).

Fresh Energy, ELPC/CEF/VS, and the Department all commented on CBAs. The Department recognized the value of cost-benefit analyses and argued that Xcel should integrate them in a more regular and widespread manner into Xcel's IDPs. Fresh Energy had more limited recommendations, with ELPC/CEF/VS' support. Both ELPC/CEF/VS and Fresh Energy supported some of the Department's wider-ranging recommendations. These parties cited concerns about affordability and a need for transparency in their recommendations.

Xcel opposed the large number of new CBA recommendations in this docket.⁷⁰ Xcel stated that this would require CBAs across nearly all planning areas, which it argued would divert limited analytical and engineering resources from forward-looking system planning. In addition, Xcel asserted that parties' recommendations "conflate planning with ratemaking and would impose prescriptive analytical obligations" after programs have ended or changed. The Company states that it supports the measured use of CBAs when useful but believes that some of the recommended CBA requirements are overly broad.

Staff summarizes specific comments below, divided by different discussion themes.

i. Calculating CBAs

The Department and Fresh Energy made recommendations for how Xcel should modify its calculation of CBAs.

Fresh Energy argued that, while Xcel's CBAs are backward-looking (to assess the cost-effectiveness of historical programs), Xcel should calculate its CBAs in a forward-looking ("ex-ante") manner and estimate the customer costs and benefits of planned program expenditures (**Decision Option 9.a**).⁷¹ Fresh Energy posited that using forward-looking CBAs would help demonstrate customer benefits before investments are made, and that they could be a critical tool in future IDPs. ELPC/CEF/VS supported this recommendation.⁷² Fresh Energy also recommended that Xcel reflect the present value of costs (measured as revenue requirements) and benefits over the life of the assets in CBAs (**Decision 9.b**).

Xcel did not support Fresh Energy's recommendation for forward-looking CBAs (**Decision Option 9.a**).⁷³ The Company argued it does not yet have full capabilities to do this, and that it preferred to expand and progress CBA methods gradually over planning cycles instead of instituting a final one in a single filing like the IDP.

⁷⁰ Xcel 3-19-26 Reply Comments, pp. 5-6.

⁷¹ Fresh Energy 4-23-26 Reply Comments, pp. 1-2.

⁷² ELPC/CEF/VS 4-23-26 Reply Comments, pp. 16-17 (PDF pp. 18-19)

⁷³ *Id.*, at 11-12 of Attachment A

However, Xcel agreed to Fresh Energy's other recommendation that CBAs should reflect the present value of costs, measured as revenue requirements, and benefits over the life of the assets, consistent with other programs (**Decision Option 9.b**).^{74,75}

The Department conducted an in-depth review of Xcel's CBA calculations and found what it deemed to be flaws in Xcel's assumptions:

- Xcel attributes most outages to asset age, rather than the possibility of other causes (e.g. weather, animals), and therefore does not assume that outages can happen with brand new equipment.⁷⁶
- Xcel counts total minutes out by substation, without normalizing for the number of customers – therefore, a substation with a long outage but few customers may be seen as causing more CMOs than a substation with a shorter outage but more customers.⁷⁷

The Department thus recommended several steps for Xcel to refine its CBAs:

Decision Option 10: Order Xcel to perform all programmatic cost benefit analyses to calculate costs and benefits as follows:

- a. All benefits and costs should use only marginal calculations;
- b. All benefits and costs should be calculated in the present value of costs;
- c. All cost calculations should be quantified over the full lifecycle of the program and its alternative case with no program expenditures;
- d. All benefit calculations should avoid averaging and should be appropriately normalized unless Xcel can demonstrate why normalization is not necessary; and
- e. Where statistical analysis is used, Xcel's models should account for variance that can be explained by other factors than the primary variable of interest.⁷⁸

After having concluded that, based on Xcel's own calculations, the End-of-Life Replacement Breakers program and the Grid Reinforcement program are not cost-effective,⁷⁹ the Department recommended that Xcel refile CBAs using the recommendations above (**Decision Option 11**).

Fresh Energy recommended instead that Xcel include an ex-ante CBA (per **Decision Option 9**) in future IDPs or rate case applications demonstrating that the customer benefits exceed the costs of its planned Grid Reinforcement expenditures (**Decision Option 12**).

Xcel opposed these recommendations, stating that the analyses provided in its 2025 IDP "reflect the Company's established planning and risk assessment approaches and are designed

⁷⁴ Fresh Energy 2-26-26 Initial Comments, pp. 12-13.

⁷⁵ Xcel 3-19-26 Reply Comments, Attachment A, p. 16 (PDF p. 24).

⁷⁶ Department 4-23-26 Reply Comments (Public Version), p. 52 (PDF p.58)

⁷⁷ Department 4-23-26 Reply Comments (Public Version), p. 53 (PDF p.59)

⁷⁸ Department 4-23-26 Reply Comments (Public Version), p. 55 (PDF p.61)

⁷⁹ Department 2-27-26 Initial Comments (Trade Secret Version), pp. 89-90 (PDF pp. 97-98).

to inform system-level investment decisions.”⁸⁰ However, Xcel did agree with the Department to discount all benefit calculations used in programmatic CBAs, consistent with standard utility and regulatory financial practices.

ii. Discretionary Program CBAs and Periodic Reviews

The Department made two recommendations for determining the cost benefit of large investments and reviewing those on a regular basis.

First, the Department recommended that the Commission order Xcel to provide a cost benefit analysis of at least three discretionary programs in its next IDP, to assess the need for these programs against affordability concerns for ratepayers.⁸¹ The Department recommended that Xcel select these programs from those with a total five-year budget of at least \$250 million. After some feedback from Xcel, which said that it was open to doing cost-benefit analyses for three discretionary programs but opposed the \$250 million threshold, the Department added that Xcel shall meet its \$250 million goal unless the Company can demonstrate that no portfolio of projects can meet the goal under the following screening criteria:

- a. Clear, quantifiable benefit streams (such as avoided Customer Minutes Out (CMOs) or targeted operations and maintenance (O&M) savings),
- b. Stable and reliable data inputs, and
- c. No mandatory components triggered by inspection thresholds or safety requirements.

(Decision Option 13)

The Department also recommended that the Commission order Xcel to provide an update to each program’s CBA ten years after the initial presentation of the CBA, for discretionary programs named above that are presented in future IDPs, and the End-of-Life Replacement and Grid Reinforcements programs (**Decision Option 14**).

CUB supported both recommendations, citing “increasing transparency” and avoiding ballooning affordability burdens for ratepayers.⁸²

Xcel opposed **Decision Option 14**.⁸³ The Company explained that its planning and investment decisions are based on 5-year horizons, which aligns with the scope of programs. Since many programs may be changed, replaced, or ended before a 10-year mark, the recommendation would create updates for programs that may no longer exist by that time. In addition, Xcel argued that it must be able to exercise flexibility to reprioritize investments, and this could be hampered by a 10-year requirement.

⁸⁰ Xcel 3-19-26 Reply Comments, Attachment A, pp. 15-16 (PDF pp. 23-24).

⁸¹ Department 4-23-26 Reply Comments (Trade Secret Version), pp. 21-22 (PDF pp. 27-28)

⁸² CUB 4-23-26 Reply Comments, pp. 2-3.

⁸³ Xcel 3-19-26 Reply Comments, Attachment A, p. 18 (PDF p. 25).

iii. CBA for New Distribution Programs and Outcome Evaluations

The Department, with support from CUB, ELPC/CEF/VS, and the City of Minneapolis, recommended that Xcel to submit CBAs of major new programs in IDP proceedings ahead of requesting recovery in its rate cases.⁸⁴ The Department cited Xcel's proposal for cost recovery of its Wildfire Mitigation Plan, proposed first in its 2024 rate case, and then proposed for program review in this 2025 IDP filing, as the reason for this recommendation. The Department argued that IDPs, rather than rate cases, are the best place to review program design before the Company starts requesting cost recovery.

The Department thus proposed, and CUB, ELPC/CEF/VS, and Minneapolis agreed, that the Commission should create a new filing requirement stating:

Decision Option 15: All new distribution spending projects and programs with an estimated historical or forecasted five-year budget of \$25 million or greater shall, at minimum, address the following:

- a. Estimated cost or range for the project/program;
- b. Consideration of feasible alternatives to the proposed spending;
- c. Quantitative estimation of expected outcomes; and
- d. Sensitivity analysis of cost and outcome assumptions.^{85,86,87,88}

Xcel opposed this recommendation, arguing that this would “blur the distinction between planning and ratemaking proceedings.”⁸⁹ Xcel claimed that it would need to add significant staffing resources to support the development, review, and maintenance of these analyses.

The Department also emphasized the need to evaluate actual outcomes of distribution investments against the utility's forecasted expenditures. The Department recommended the Commission order all new Xcel spending projects with a five-year budget over \$25 million, that were approved for cost recovery since 2021, report five years of actual outcomes compared to forecasted outcomes in the IDP (**Decision Option 16**). ELPC/CEF/VS,⁹⁰ the City of Minneapolis,⁹¹ and CUB⁹² agreed.

Xcel opposed this proposal, claiming that an unclear definition of “outcomes” “risks imposing vague, duplicative, or inconsistent reporting obligations across projects with differing

⁸⁴ Department 2-27-26 Initial Comments (Public Version, pp. 17-18 (PDF pp. 25-26).

⁸⁵ Department 4-23-26 Reply Comments, p. 78 (PDF p. 84).

⁸⁶ CUB 4-23-26 Reply Comments, p. 3.

⁸⁷ ELPC/CEF/VS 4-23-26 Reply Comments, p. 21 (PDF p. 23).

⁸⁸ City of Minneapolis 4-23-26 Reply Comments, p. 4.

⁸⁹ Xcel 3-19-26 Reply Comments, Attachment A, p. 19 (PDF p. 27)

⁹⁰ ELPC/CEF/VS 4-23-26 Reply Comments, pp. 17-18 (PDF pp. 19-20).

⁹¹ City of Minneapolis 4-23-26 Reply Comments, p. 4.

⁹² CUB 4-23-26 Reply Comments, p. 3.

objectives, timelines, and performance metrics.”⁹³ The Company also argued that its forecasts are not static, but the Company regularly revisits and adjusts them in response to evolving conditions.

The Department argued that this would be beneficial because:

- a. Any sensitivity/cost-benefit analysis could be used in the record for future cost-recovery proposals,
- b. Analyzing the value of a program is iterative, while a rate case cost recovery request is timebound and strict in structure, and
- c. It does not believe that this specific request is addressed in other IDP filing requirements.⁹⁴

iv. Staff Analysis

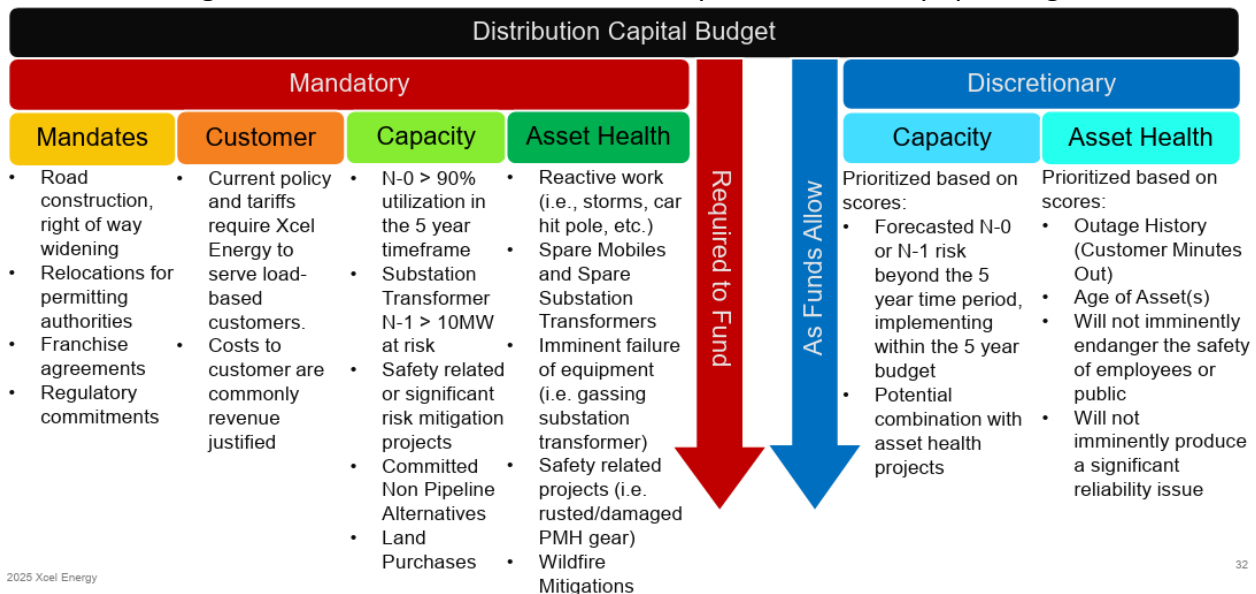
The robust stakeholder feedback on Xcel’s two cost benefit analyses indicate the importance of developing CBAs as a tool for cost recovery proceedings. Staff makes two observations. First, like a class cost of service study or an IRP model, there is no one “correct” way to perform a cost benefit analysis. Second, without application of CBA as a tool for decision making in a cost recovery proceeding, they exist largely as a theoretical exercise. Staff is concerned that the recommendations from stakeholders in the current proceeding fall into these two traps, which risks the CBAs getting stuck in an endless feedback loop and doing little to contain rising distribution costs.

Under Xcel’s breakdown of mandatory versus discretionary distribution spending not optional and are required to provide service and/or maintain safety and reliability.

⁹³ Xcel 3-19-26 Reply Comments, Attachment A, p. 8 (PDF p. 16).

⁹⁴ Department 4-23-26 Reply Comments, p. 20 (PDF p. 26).

Figure 18: Xcel Breakdown of Mandatory vs. Discretionary Spending⁹⁵



Some programs may not be “cost effective” under a cost benefit analysis, but they are necessary public good. For these types of programs, Staff believes that a “least cost/best fit” analysis could a better approach to determining which from a range of options gives ratepayers the most value for its money. Vermont is investigating using a combination of both cost benefit analysis and least cost/best fit to evaluate reliability and resiliency improvements to address increasing storm outages. In that proceeding, the Department of Public Service recommends establishing a baseline level of resiliency and using a cost benefit analysis framework for any investments that would improve reliability beyond that baseline.⁹⁶ Using a combination of different analyses can also avoid biasing reliability investments towards higher-income and commercial customers at the expense of underserved communities.

Staff recommends a modified version of party recommendations that is targeted towards ensuring there is adequate information in cost recovery proceedings for parties to scrutinize Xcel’s proposed investments. **(Decision Option 17)**

In all future rate cases require Xcel Energy to include a cost benefit or least cost/best fit analysis for any discretionary distribution capital programs that average more than \$4 million per year in capital expenditures during the term of the filed rate case.

Staff based the \$4 million per year average budget threshold on Xcel’s response to Staff IR 7.⁹⁷ Based on this threshold five programs have a 5-year average of more than \$4 million, including the Grid Reinforcement and ELR Breakers programs for which the Company has already completed CBAs. Because this recommendation would apply to all programs that hit a certain spending threshold in a rate case, Staff believes it would accomplish the goals of **Decision**

⁹⁵ Xcel Energy, CBA Workshop 1 Materials, Attachment A, p. 32 (PDF p. 33)

⁹⁶ Powering through Change: Affordable Grid Resilience Amid Climate and Demand Pressures; Resilience Proceeding Findings and Recommendations – June 2026. Vermont Department of Public Service. Accessed via <https://emp.lbl.gov/publications/technical-assistance-vermont>

⁹⁷ Xcel Response to [Staff IR 7](#), 6-1-26

Options 12, 13 and 14. Any time Xcel brings forward a rate case, it would need to update the analyses to prove the program remains cost effective for customers, which would address the Department's desire to analyze the actual results of the program.

Staff believes this recommendation accomplishes many of the goals of other decision options but places the information squarely where it can be the most useful: in a cost recovery proceeding. For example, in the Company's most recent rate case both the ELR Breakers and Grid Reinforcement programs were approved without any objection from the Department or other parties. Other areas of the distribution capital budget were also largely unscrutinized, except for Xcel's Targeted Undergrounding Proposal and discrete capacity projects. The lack of analysis of Xcel's distribution budget has been a trend for multiple rate cases. Unless a CBA is used to justify a utility's budget in a rate case proceeding, it is purely a theoretical exercise.

As in prior IDPs, Staff is generally not in favor of being overly prescriptive with how a utility (or any other party) performs its CBA. That said, the Department provided strong and persuasive analysis of Xcel's CBA that point to significant flaws in Xcel's methodology. This feedback is valuable for Xcel ahead of filing for cost recovery so it can correct the CBA and determine whether the programs continue to be cost effective. The IDP is a good venue to have a discussion of whether modifications to the CBA process are necessary, therefore Staff recommends **Decision Option 17** which would address the Department's **Decision Option 15**.

In future IDPs, require Xcel Energy file any cost benefit or least cost/best fit analyses to for discretionary distribution capital investments that were performed for its most recent rate case as an appendix or attachment.

While future refinement or tweaks may be needed, Staff believes that getting CBAs incorporated into the rate case where they can be cross examined through testimony is the most efficient way to start using them to contain costs.

For the next IDP, Staff suggests stakeholders and Xcel work on how to incorporate alternatives analysis and least cost/best fit analysis for non-discretionary distribution investments that are not in reaction to an immediate outage (such as equipment failure or a storm-related outage). Staff agrees with stakeholders that trying to assess alternatives is a key feature of ensuring prudent distribution investments but believes that it should be incorporated into existing cost recovery proceedings.

As rate cases in Minnesota use a forward test year, they assess whether the proposed budget for future years is reasonable by comparing it to historical spending. Therefore, there is ample room to have the utility provide various analyses with initial testimony that justify their proposed spending decisions.

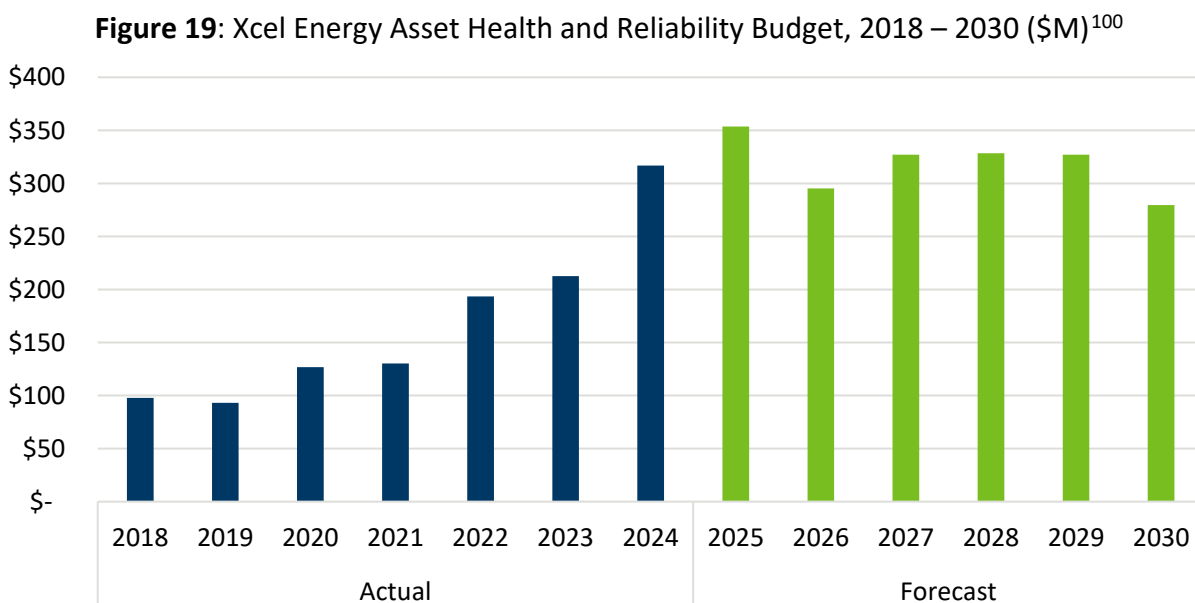
D. Reliability

1. Asset Health and Reliability Budget

The Minnesota portion of the NSPM electric distribution system includes nearly 28,000 miles of distribution lines and 1,200 feeders.⁹⁸ Under Xcel’s Asset Health and Reliability Management Plan, Xcel maintains and upgrades its system to reduce outages, improve performance, and manage long-term costs. 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.

Xcel’s expected budget for this category is \$1.9 billion for 2025 through 2030 and accounts for the largest percentage of the distribution budget.⁹⁹



⁹⁸ Xcel Integrated Distribution Plan, Chapter 2, p. 4 (PDF p. 136).

⁹⁹ Xcel Integrated Distribution Plan, pp. 8- 9 (PDF pp. 26-27)

¹⁰⁰ Xcel Integrated Distribution Plan, p. 9 (PDF p. 27).

Xcel's routine Asset Health & Reliability projects include the following:

Table 4: Asset Health and Reliability Programs

Vegetation Management	Includes pruning, tree and brush removal, mowing, and herbicide application along and near rights-of-way.
Arrester Replacement Program	Targets arresters on overhead feeder lines that have higher-than-average failure rates.
Low Cost Recloser Program	Economic program to supplement the Company's standard Viper SP reclosers. Unique, single-phase, electronically controlled recloser that mounts directly to a cutout.
Feeder Performance Improvement Program	A program to identify locations where there is opportunity to improve the reliability of the distribution system to reduce service interruptions.
Pole Inspection and Pole Top Reinforcement Program	Replacing and reinforcing poles to improve system performance especially during high wind conditions, icing, and heavy snow.
Porcelain to Polymer Cutout Replacement Program	Replacing porcelain cutouts with polymer cutouts on overhead feeders to reduce equipment failure.
Substation Renewal Program	Improves the reliability and resiliency of the Company's substations through the replacement of key substation components.

Xcel also replaces many miles of cables in each IDP cycle:

Table 5: Forecasted Cable Replacement Capital Budgets (2026 – 2030), (\$ millions)¹⁰¹

	2026	2027	2028	2029	2030	2026-2030
Forecasted reactive cable replacements	\$24.00	\$23.70	\$24.80	\$17.00	\$26.30	\$124.20
Forecasted proactive cable replacements	\$16.00	\$15.80	\$16.50	\$25.50	\$17.60	\$82.80
Total forecasted cable replacements	\$39.90	\$39.40	\$41.30	\$42.50	\$43.90	\$207.00

Fresh Energy found that Xcel's methodology for prioritizing its AH&R was opaque and did not adequately justify its large budget.¹⁰² Fresh Energy found that certain parts of the forecasted budget are listed as "placeholders," which Xcel explained as projects that are yet to be identified, but allows it to address emerging and unforeseen risks that it nevertheless wants to be financially prepared to address.¹⁰³ Fresh Energy offered a general recommendation to require Xcel to provide more transparency into its methodology for prioritizing Asset Health and Reliability projects/programs and establishing associated budgets (**Decision Option 19**).

¹⁰¹ Xcel Integrated Distribution Plan, Chapter 6, p. 15 (PDF p. 263).

¹⁰² Fresh Energy 2-26-26 Initial Comments, pp. 5-7.

¹⁰³ Fresh Energy 2-26-26 Initial Comments, pp. 6-7.

Fresh Energy also recommended that Xcel develop a methodology for estimating the expected reliability improvements from its AH&R expenditures (**Decision Option 20**). Fresh Energy pointed to utilities in Michigan (DTE Electric¹⁰⁴) and Illinois (Ameren Illinois Corporation¹⁰⁵), which have developed specific reliability metrics (e.g. spending on certain asset health initiatives to target a specific decrease in SAIDI). Fresh Energy argued that this step could be valuable for Xcel's cost-benefit analyses, on which Fresh Energy provided other recommendations (**Decision Options 9, 10, and 11**).

Xcel disagreed that its AH&R investments were opaque, arguing that ascribing "placeholder" to certain funding "reflects standard asset management practice across the utility industry, where specific projects cannot always be identified several years in advance."¹⁰⁶ Xcel explained that "placeholders" represent funding for working capital, blanket projects, and programs intended to address emerging reliability risks, unforeseen asset failures, storm damage, and evolving system conditions, and are based on historical investment trends, asset age and condition data, failure history, and reliability performance metrics, while allowing flexibility to adapt to emerging situations.¹⁰⁷

Xcel also opposed Fresh Energy's recommendation to develop a methodology to quantitatively estimate the expected reliability improvements associated with AH&R expenditures:

Reliability outcomes vary significantly by asset type, location, operating environment, and weather conditions. In addition, a substantial portion of AH&R spending is reactive in nature—such as replacing assets damaged by storms, vehicle impacts, or sudden failures—making it difficult to forecast project-level reliability benefits several years in advance. Developing a universal predictive model under

¹⁰⁴ Fresh Energy 2-26-26 Initial Comments, p. 6: "DTE Electric's Reliability Model calculates expected circuit-level reliability improvements (with and without major storm impacts) for several of its major programs, including tree trimming, 4.8 kV conversions, pole and pole-top maintenance/modernization, and distribution automation. In its 2025 rate case proceeding, DTE Electric applied the model to demonstrate that its proposed spending, if approved, would improve all-weather SAIDI by 57% by 2029."

Michigan Public Service Commission Case No. U-21860, April 24, 2025, Direct Testimony of Allen J. Kryscynski, pp. AJK-33 – AJK-40. <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000InllwAAI>.

¹⁰⁵ Fresh Energy 2-26-26 Initial Comments, pp. 6-7: "Ameren Illinois Corporation ("AIC") has developed a Right-Sizing Reliability Framework in response to the Illinois Commerce Commission's order for AIC to support the level and pace of its proposed reliability-related expenditures. The four-step framework begins by projecting expected outages for certain asset classes considering climate projections, historic performance, asset age and condition, and capacity needs. AIC then translates outage projections into pre-investment risk by monetizing the likelihood and consequence of failure. AIC next identifies investments to address system needs through its standard planning and engineering processes, categorized as baseline (maintaining existing performance) or incremental (improving performance). Finally, the full portfolio is evaluated against performance targets to generate post-investment reliability projections. In its 2026 Grid Plan filing, AIC applied the framework to demonstrate that its planned expenditures will result in achievement of its 2028-2031 SAIDI performance targets."

Illinois Commerce Commission Docket No. 26-0051, January 20, 2026, Ameren Exhibit 5.0 – Direct Testimony of Brian DeMent, pp. 17-30. <https://www.icc.illinois.gov/docket/P2026-0051/documents/375155>.

¹⁰⁶ Xcel 3-19-26 Reply Comments, Attachment A, p. 19 (PDF p. 27).

¹⁰⁷ Xcel 3-19-26 Reply Comments, Attachment A, pp. 19-20 (PDF pp. 27-28).

these conditions risks producing results that are inconsistent, misleading, or not useful for decision-making.¹⁰⁸

Xcel also noted that AH&R planning differs from capacity-driven planning processes and so the comparison to these other utilities is inappropriate.

2. *Value of Reliability*

The Department introduced the concept of developing a “value of reliability” for Xcel, to inform and assess distribution system investments in IDPs.¹⁰⁹ The Department argued that the distribution budgeting process should incorporate societal costs – e.g. an expected reduction in outages – to calculate the value of investing in a project meant to increase reliability. For example, new underground lines can be twice as expensive as overhead lines, but if they significantly improve reliability, the Department argued that that cost may be quantifiably justified.

Xcel stated that it calculates its reliability standard based on an economic value of customer minutes out (CMO) of \$3.05/CMO, which is a weighted average between its residential and non-residential customers.¹¹⁰ Xcel assumes a large gap between the value of a minute of outage for a business customer and a residential customer, and the Department noted that this leads to a major sensitivity (e.g. a shift in customer demographics could greatly affect the \$/CMO amount).

The Department noted that MISO’s reliability standard (Value of Lost Load, or VOLL), assigns a value of \$10,000/MWh of unserved energy, and the Department argued that this value does not align with Xcel’s \$/CMO calculation.^{111,112} Xcel argued that this was inaccurate, and that it did in fact utilize values that “closely align with MISO’s approved System VOLL of \$35,000/MWh, with slight differences due to inflation and customer-specific factors.”¹¹³

The Department argued that Xcel misunderstood the applicability of these values, and provided in-depth statistical analysis on the value of unserved versus served energy, LMPs, and BCRs. As a result of these analyses, the Department argued that Xcel should develop clear calculations on the value of reliability, in order to inform electric utilities’ distribution system investments.¹¹⁴ The Department recommended that the Commission delegate authority to the Executive Secretary to issue a Notice of Comment Period in each IDP docket to discuss the appropriate value of reliability, including the following topics:

- The valuation of the cost of unserved energy;

¹⁰⁸ Xcel 3-19-26 Reply Comments, Attachment A, p. 20 (PDF p. 28).

¹⁰⁹ Department 2-27-26 Initial Comments, pp. 31-37 (PDF pp. 39-45).

¹¹⁰ Department 2-27-26 Initial Comments, pp. 33-34.

¹¹¹ Department 2-27-26 Initial Comments, pp. 35-37.

¹¹² Department 3-11-26 Errata Letter, pp. 4-6.

¹¹³ Xcel 3-19-26 Reply Comments, Attachment A, p. 28 (PDF p. 36)

¹¹⁴ Department 4-23-26 Reply Comments, pp. 26-29 (PDF pp. 32-35)

- The use of price caps for the cost of unserved energy;
- Forecasting methodologies for reliability benefits;
- Appropriate uses cases for the value of reliability; and
- The potential to employ different values of reliability by customer class.

(Decision Option 21)

The Department suggested that Xcel refrain from any targeted undergrounding projects until this comment period has closed, but Staff notes that the Commission recently approved the Company's targeted undergrounding budget for 2025 and 2026 in the Company's rate case.

Xcel opposed this recommendation.¹¹⁵

i. Staff Analysis

First, Staff believes it is important to clarify that trying to compare the values generated by the ICE 2.0 calculator and the MISO Value of Lost Load (VOLL) is a false equivalency. MISO's VOLL is a market construct meant to establish a maximum price the market is willing to pay generators to avoid involuntarily shedding load on the bulk power system. The price cap placed on the VOLL is a ratepayer protection mechanism to avoid market manipulation under extreme circumstances. By contrast, LBNL's ICE 2.0 calculator provides an estimate of the value of a Customer Minute Out (CMO) by factoring the economic impacts the loss of power would have on utility customers. In other words, MISO's VOLL is calculating the cost to *avoid* an outage, while the ICE calculator is measuring the economic impact *of* an outage.

Staff is very concerned that the Department's recommendations could have significant unintended consequences for electric system reliability for underserved communities, which have already been proven to have disparately bad reliability compared to wealthier areas of Xcel's service territory.¹¹⁶ Starting to apply a value of reliability by customer class would likely result in projects that serve commercial customers being prioritized over residential. Xcel emphasized this point in its response to Staff IR 10:

Applying differentiated reliability values would increase the relative valuation of service to non-residential customers compared to residential customers. This approach would be a significant shift from prior Commission direction. For example, in Order Point No. 6 of the Commission's December 5, 2023 Order in Docket No. E002/M-23-73, the Commission directed the Company to "discuss how to lower the differences in SAIDI, SAIFI, and CAIDI between feeders associated with the different customer classes in their 2024 filing." The proposal is both a significant change from prior Commission guidance and has impacts relating to equity in service quality.¹¹⁷

¹¹⁵ Xcel 3-19-26 Reply Comments, Attachment A, p. 28 (PDF p. 36)

¹¹⁶ See Xcel's 2023 SRSQ, Docket E002/M-24-27, TCR and Pradhan Chan studies.

¹¹⁷ Xcel response to Staff IR 10.

Staff talked with reliability experts from LBNL using the Lab's State Technical Assistance Program. Through this technical assistance, Lab experts indicated they would be available to present at a technical workshop to go into more depth on the ICE calculator, reliability valuations, and ways of assessing reliability improvements and alternatives. Staff believes that a technical workshop of this manner would be a better starting point than a wide ranging proceeding on reliability valuation.

As discussed above in the CBA section, Vermont has initiated a combination of doing least cost/best fit and cost benefit analysis for reliability investments that balances affordability and reliability. Through the state technical assistance program, LBNL could provide similar help to Minnesota. This could also address calls from ELPC/CEF/VS to ensure reliability projects are distributed equitably throughout Xcel's service territory.

Therefore, as an alternative to the Department's proposed docketed process, Staff suggests the Commission delegate authority to the Executive Secretary to hold one or more technical workshops facilitated by Commission Staff on how to value reliability in distribution proceedings and investment decisions (**Decision Option 22**). This would also allow for additional stakeholder education on how the ICE.2 calculator was constructed and how it differs from valuation on the bulk power system.

3. Targeted Undergrounding

Xcel stated that it launched a new initiative focused on targeted undergrounding using data to prioritize areas of its grid where it will move overhead distribution lines underground.¹¹⁸ The Company's initial budget was approved as part of its recent rate case. Xcel stated that its intent with this initiative was to improve storm resilience, enhance public safety, and lower operational costs, and that it would use criteria that included outage frequency and duration, and asset condition, as well as equity and demographic considerations from a third-party evaluation to select sites for undergrounding.^{119,120}

Xcel proposed to invest in this initiative in phases between 2025 – 2030, starting with areas with high outage volumes and lower construction complexity, and scaling up for a total investment of \$233.7 million.

¹¹⁸ Xcel Integrated Distribution Plan, p. 12 (PDF p. 30).

¹¹⁹ Xcel Integrated Distribution Plan, Chapter 2, p. 6 (PDF p. 138).

¹²⁰ Docket No. E-002/M-24-27, *In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report*, [Order Accepting Reports and Setting Additional Requirements \(January 13, 2025\)](#), Ordering Paragraph 46: "Xcel must hire an independent third-party evaluator with expertise in evaluating racial disparities to conduct a one-year study that will evaluate Xcel's practices and policies related to capital investment planning, outage restoration practices, and shutoff practices to better understand the causes of these discrepancies in shutoff rates and service reliability. Xcel must engage interested stakeholders to participate and collaborate with the independent third-party evaluator."

Table 6: Planned Capital Investments in Targeted Undergrounding (millions) (2025 – 2030)¹²¹

Year	Capital Spend (\$M)	Phase
2025	\$1.50	Initial • CEMI/DEMI-driven targeting • Flag segments for engineering review based on flexible thresholds • Build out foundational targeting and review processes
2026	\$8.00	
2027	\$25.00	Scaling • Begins mid-2026 • Using system-wide reliability metrics • SAIDI/SAIFI/CELI analysis, feeder-level ranking, predictive storm modeling • Scale prioritization using data-driven insights
2028	\$62.00	
2029	\$67.50	Final • Begins mid-2028 • Broad deployment and integration • Feeder-level undergrounding, regional optimization, integration with automation, vegetation management, and electrification readiness. • Maximize reliability and equity impact
2030	\$69.70	
Total	\$233.70	

i. Case Studies of Comparable Utilities

Xcel pointed to examples of other utilities who have used targeted undergrounding with the goal of improving resiliency and reducing outages. Xcel cited Wisconsin Public Service Corporation, Potomac Electric Power Company, Duke Energy Florida, and Florida Power & Light's programs, showing a reduction in SAIDI and SAIFI over the time that the utilities moved distribution lines connected to particularly outage-prone feeders underground.¹²²

ii. Alternatives Considered

Xcel included rationale for why it proposed investing in Targeted Undergrounding, as opposed to other alternatives that may be more affordable.¹²³

- **Overhead Line Rebuilds** would replace aging overhead infrastructure but, according to Xcel, would not eliminate exposure to weather-related events, one of the key goals of targeted undergrounding.
- **Enhanced Vegetation Management** “can reduce outage risk but does not eliminate it,” Xcel said in its petition.¹²⁴ Xcel argued that it can often be expensive depending on the location of the vegetation (e.g. backlot versus roadside lines), and that it does not have

¹²¹ Xcel Integrated Distribution Plan, Chapter 2, pp. 6 and 20 (PDF pp. 138 and 152).

¹²² Xcel Integrated Distribution Plan, Chapter 2, pp. 7 – 11 (PDF pp. 139-143). This section includes graphs of the SAIDI and SAIFI of each of these utilities benchmarked against the IEEE US Average.

¹²³ Xcel Integrated Distribution Plan, Chapter 2, pp. 11-13 (PDF pp. 143-145).

¹²⁴ Xcel Integrated Distribution Plan, Chapter 2, p. 12 (PDF pp. 144).

data to quantify reliability benefits or duration of impact. In its 2024 rate case, Xcel also argued that certain lines it has targeted for undergrounding have trees located outside the right-of-way “which limits the extent of reliability improvement possible from vegetation management.”¹²⁵

- **Fault Location, Isolation, and Service Restoration (FLISR) Technology** is, according to Xcel, effective for managing short duration outages where there are switch points to alternate source lines, rather than resolving long-duration outages caused by severe weather or physical infrastructure damage.¹²⁶

iii. Scenarios Analyzed

Xcel analyzed two scenarios to try to quantify the benefit of undertaking targeted undergrounding in this manner: first by feeders identified with high outages in its 2023 SRSQ, and then feeders by census block group identified as having high CELI-12 rates in its 2024 SRSQ.¹²⁷ Xcel found the highest benefit-cost ratio for the first scenario, using the estimated avoided 10.5 million Customer Minutes Out and the value of an uninterrupted minute of service calculated by the Lawrence Berkeley National Laboratory, should it underground all 49 feeders.

iv. Site Selection Criteria

Xcel proposed to first target segments of its distribution system where customers and/or devices have experienced multiple service interruptions (CEMI/DEMI) within a rolling 12-month period.¹²⁸ Xcel proposed to then flag these areas for a deeper engineering review and technical assessment of the asset condition, access constraints, historical outage trends, and more factors. Xcel explained that, as the program scales, it will prioritize based on system-wide reliability data, including SAIDI, SAIFI, and CELI and predictive storm impact modeling. Below is an example of a targeted undergrounding project that the Company is currently undertaking: a line section serving 166 customers in St. Paul, with CELI-12 rates of 77.3% and CEMI-6 rates of 30.45% over three-year averages. In 2023 and 2024, the lines and equipment targeted for undergrounding in this location were directly associated with 0.78 million CMO in total.

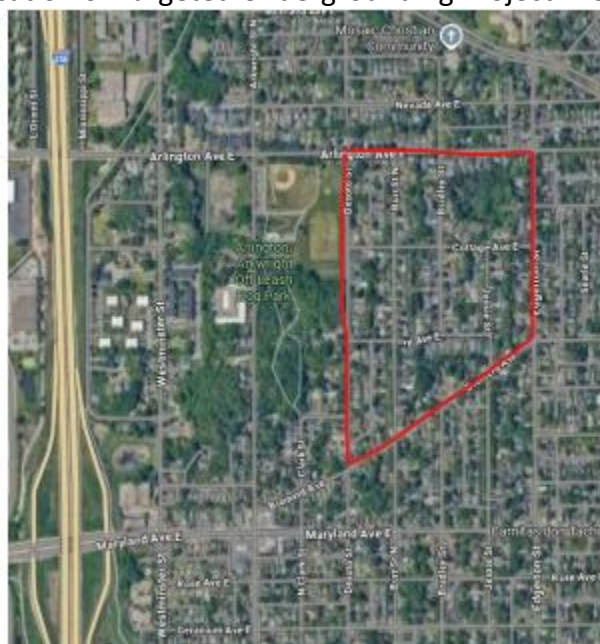
¹²⁵ Docket No. E002/GR-24-320, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, [Mensen Rebuttal 10-10-25](#), pp. 140 – 142 (PDF pp. 144-146)

¹²⁶ Xcel Integrated Distribution Plan, Chapter 2, p. 13 (PDF p. 145).

¹²⁷ Xcel Integrated Distribution Plan, Chapter 2, pp. 14-16 (PDF pp. 146-148).

¹²⁸ Xcel Integrated Distribution Plan, Chapter 2, pp. 16 – 20 (PDF pp. 148-152).

Figure 20: Location of Targeted Undergrounding Project in St. Paul, MN¹²⁹



Xcel also explained that it would use directional boring to minimize community disruption and provide advance notice to customers in the area about planned construction, including dedicated points of contact for inquiries.¹³⁰ The Company anticipated developing more standardized outreach materials as the program scales, such as direct mail, digital communications, and community meetings in order to inform customers on timelines and logistical concerns, as well as the benefits of undergrounding.

v. Party Comments

The Department agreed that there appears to be a direct correlation between overhead line miles and customer minutes out in Xcel's service territory.¹³¹ However, the Department made several recommendations regarding the program's cost-benefit. ELPC/CEF/VS focused more on integrating equity into the program and annual reporting. LiUNA supports a considered approach to targeted undergrounding that focuses on the highest risk locations.¹³²

Cost Benefit and Effectiveness

The Department scrutinized Xcel's methodology for estimating the cost-benefit of targeted undergrounding. Xcel had used a flat rate of \$1.5 million per mile to estimate costs, but the Department cited benchmarking data from the US Department of Energy, which shows that undergrounding in urban environments can range from \$2.88 million to as high as \$12 million

¹²⁹ Xcel Integrated Distribution Plan, Chapter 2, p. 19 (PDF p. 151).

¹³⁰ Xcel Integrated Distribution Plan, Chapter 2, p. 24 (PDF p. 156).

¹³¹ Department 2-27-26 Initial Comments, pp. 79-80.

¹³² LiUNA 2-27-26 Initial Comments, p. 2

per mile.¹³³ The Department also noted that Xcel plans to retain overhead service drops, which would then impact net benefits from avoiding vegetation management by not fully undergrounding any given line.

The Department expressed concern about other aspects of the programs' cost, noting that Xcel's revenue requirement for the initiative includes the costs for retirement and removal of utility assets that are not yet fully depreciated. This means that ratepayers would be paying twice for the same reliability function: once for the remaining book value of the overhead poles and wires, and again for the new underground infrastructure replacement.¹³⁴ This would leave ratepayers with the stranded asset costs of the non-depreciated assets.

The Department also argued that Xcel had not made a sufficient case for why targeted undergrounding would be more cost-effective than seemingly lower-cost alternatives (such as vegetation management and overhead line rebuilds). The Department noted the lack of a "true least-cost comparison,"¹³⁵ and noted with particular concern the dismissal of vegetation management's importance, given that it "can achieve significant reliability gains with lower capital intensity than full undergrounding."¹³⁶ The Department noted that Dakota Electric had recently recognized the value of vegetation management and contracted with a consulting firm to optimize its vegetation management strategy.

To address its overall concerns about the cost benefit and effectiveness of the program, the Department recommended that the Commission require Xcel to perform full cost-benefit analysis for all targeted undergrounding projects scheduled beyond the 2026 pilot phase, which must incorporate O&M savings (including avoided vegetation management and storm restoration costs), and use site-specific construction estimates and benefit calculations (**Decision Option 25**).

The Department also recommended that the Commission order Xcel to contract with an independent consulting firm that specializes in vegetation management to perform a comprehensive optimization of the Company's current strategy (**Decision Option 26**).

Regarding Xcel's proposed siting criteria, the Department agreed with Xcel's overall approach but recommended refinements for cost effectiveness and transparency:

- Require Xcel to demonstrate a minimum BCR of 1.25, using tools like the ICE, to financially justify each individual project prior to approval.
- Limit or strictly prioritize undergrounding to sites where existing overhead infrastructure is fully depreciated to prevent stranded costs from premature

¹³³ Department 2-27-26 Initial Comments, p. 82, referencing *Undergrounding Transmission and Distribution Lines: Resilience Investment Guide*, U.S. Department of Energy Grid Deployment Office (GDO) and UC Berkeley, (September 2024), pp. 5-6. https://www.energy.gov/sites/default/files/2024-11/111524_Undergrounding_Transmission_and_Distribution_Lines.pdf

¹³⁴ Department 2-27-26 Initial Comments, pp. 83-85.

¹³⁵ Department 2-27-26 Initial Comments, p. 84.

¹³⁶ Department 4-23-26 Reply Comments, p. 46 (PDF p. 52).

retirements.

- Require the formal quantification of alternatives, specifically enhanced vegetation management, FLISR deployment, and backlot O&M expenses, during site selection to ensure undergrounding is the most economical choice.

(Decision Option 27)

Xcel opposed the Department's recommendation for CBAs for all post-pilot undergrounding projects and incorporating O&M savings and site-specific construction estimates.¹³⁷ The Company argued that CBAs are administratively burdensome on small distribution projects and are not well-suited to situations where Xcel has a service quality obligation to improve reliability.

Xcel also opposed the Department's recommendation for new site selection requirements.¹³⁸ The Company argued that strict cost-benefit requirements and depreciation-screening could prevent the Company from addressing feeders with the most significant outage impacts.

Equity

ELPC/CEF/VS supported the Company's strategy to minimize disruption through directional boring and its planned customer and community engagement efforts.¹³⁹ However, ELPC/CEF/VS and the Department both found Xcel's incorporation of equity considerations into the program to be vague and undefined. ELPC/CEF/VS advocated that Xcel be required to integrate equity metrics more specifically, including those from the independent third-party study, and to use the Interruption Cost Estimate 2.0 Calculator from Lawrence Berkeley National Laboratory to inform decisions about site selection (**Decision Option 28**). The Department offered a more simplified version of this decision option, as it stated that it had not assessed the Berkeley Lab tool (**Decision Option 29**).

ELPC/CEF/VS also recommended that the Commission require the Company to report annually on its targeted undergrounding proposal, including:

- The number of undergrounding projects,
- Number of projects in Environmental Justice areas,
- Actual undergrounding project costs,
- Drivers for projects (engineering, equity, other), and
- Description of community engagement efforts.

(Decision Option 30)

The Department supported this recommendation.

Xcel found the ELPC/CEF/VS recommendations unclear and opposed them.¹⁴⁰ Xcel argued that the Lawrence Berkeley National Laboratory ICE tool favors higher usage, higher-income

¹³⁷ Xcel 3-19-26 Reply Comments, Attachment A, pp. 27-28 (PDF pp. 35-36).

¹³⁸ Xcel 3-19-26 Reply Comments, Attachment A, pp. 27-28 (PDF pp. 35-36).

¹³⁹ ELPC/CEF/VS 2-26-26 Initial Comments (January 26, 2026), p. 32.

¹⁴⁰ Xcel 3-19-26 Reply Comments, Attachment A, pp. 27-28 (PDF pp. 35-36).

communities, and while it was used in Xcel's analysis of the value of targeted undergrounding, it would not be a proper tool for prioritizing where to underground lines. The Company noted that it was obligated to adhere to the independent third-party equity study that the Commission previously ordered before modifying its approach on incorporating equity.

ELPC/CEF/VS responded that the ICE tool allows users to explore scenarios with different income levels, which could "allow the Company to reflect the disproportionate impact of outages on lower income customers as expressed in cost per event as a percentage of daily household income."¹⁴¹ The parties also argued that adherence to a third-party equity study "does not preclude Xcel from formulating a plan with specific steps for how it plans to use the third-party study and indeed, the third-party study will be most effective if Xcel has an implementation plan ready when the third-party study results are released."¹⁴²

vi. Staff Analysis

Staff shares the Department's concerns about Xcel's deprioritizing vegetation management as a reliability strategy in favor of cost- and capital-intensive targeted undergrounding.

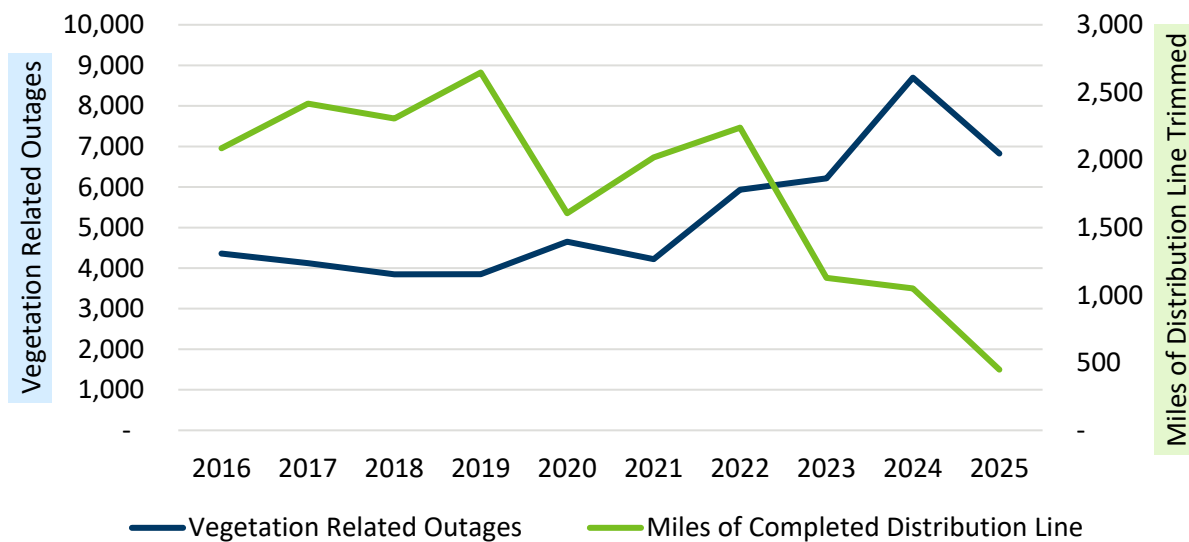
Xcel regularly cited its vegetation management program as a key component of reliability, including in its Wildfire Mitigation Program, saying that it "remains a cornerstone of our strategy."¹⁴³

However, Xcel has significantly decreased the number of miles of tree trimming it has completed annually: from a high of 2,647 miles of overhead lines in 2019 to just 449 in 2025. Correspondingly, the number of vegetation caused outages has risen from around 4,000 outages per year to a high of over 8,600 in 2024.

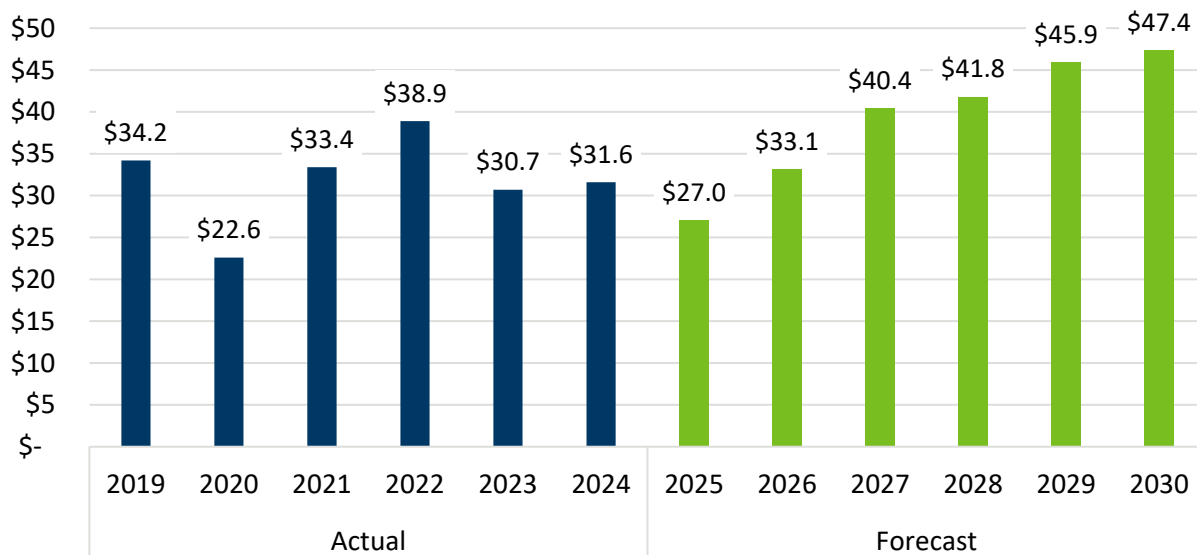
¹⁴¹ ELPC/CEF/VS Reply Comments, p. 11.

¹⁴² ELPC/CEF/VS Reply Comments, p. 10.

¹⁴³ Xcel Petition, p. 14.

Figure 21: Vegetation Caused Outages and Miles of Distribution Line Trimmed¹⁴⁴

Based on its filing in the 2024 SRSQ docket, Figure 22 depicts Xcel's vegetation budget from 2019 through 2030. Xcel forecasted that its budget would continue to steadily increase in the IDP's five-year period. Xcel cited rising labor costs and increased wildfire prevention spending as reasons for the increases.¹⁴⁵

Figure 22: Distribution Vegetation Management Budget, 2019-2030 (\$ M)¹⁴⁶

¹⁴⁴ Docket E002/M-26-27, Xcel Energy Compliance Filing Part 2 of 3, April 1, 2026, Attachment J, Table 2, p. 9; Attachment K

Docket E002/M-20-406, Xcel Energy 2019 Annual Service Quality Performance Report and Proposed Reliability Measures, April 2, 2020, Attachment 3, Table 2, p. 4

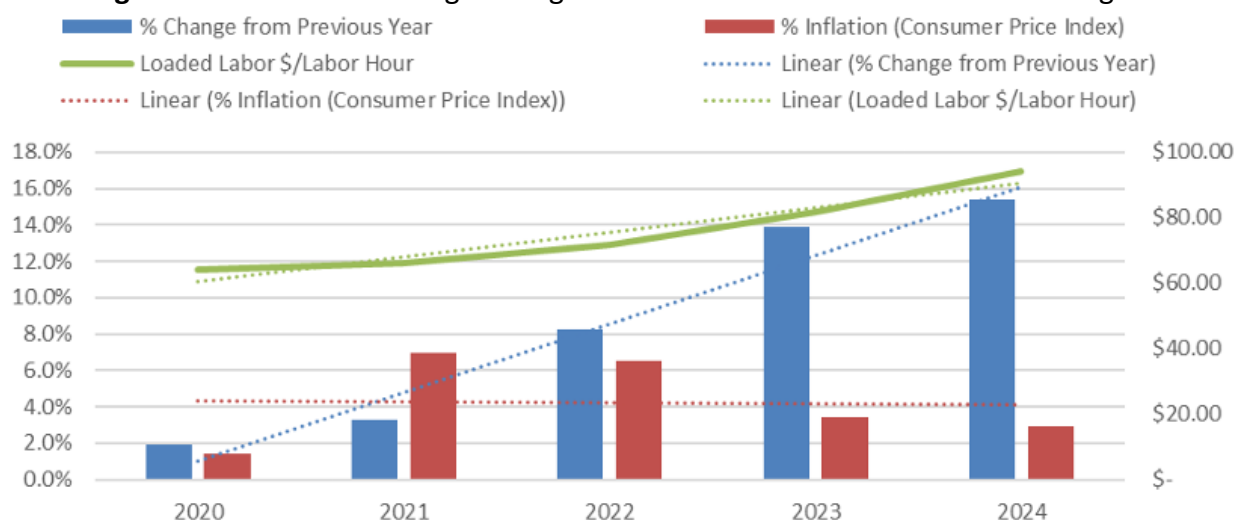
Docket E002/M-21-237, Xcel Energy, Compliance Filing, January 1, 2022, Tab 1, Minnesota SCI Cause Summary

¹⁴⁵ Xcel Integrated Distribution Plan, Chapter 6, p. 21 (PDF p. 269).

¹⁴⁶ 2024 SRSQ, [Department Initial Comments, Attachment DOC-1, Page 2 of 2 \(July 11, 2025\)](#)

So while Xcel is trimming less trees, the cost of the vegetation management program has steadily gone up, as have the number of vegetation-related outages. In the 2025 SRSQ docket, the Department ran an analysis to show the cost increase of vegetation management over time, comparing it to inflation:

Figure 23: Annual Percentage Change in Loaded Labor Costs for Tree Trimming¹⁴⁷



The Department then examined the number customer interruptions attributed to trees and found that it had jumped by 73% in 2024 compared to the average of the past five years, while the number of miles of trees trimmed was 47% below the five-year average.¹⁴⁸

The Department drew two conclusions:

- That Xcel was trimming fewer miles of overhead distribution line, on average, compared to five previous years,
- That it was costing more per mile, increasing at a rate that exceeded inflation, and
- There appeared to be a possible correlation between the decrease in tree trimming and the increase in customer outages.¹⁴⁹

The Department hypothesized that rising labor costs drove the decrease in work. Xcel confirmed this in its 2024 Rate Case, where a representative testified that internal labor annual base pay increases and demand for contractor resources, in addition to some rapid growth cycles and increased customer requests, drove the cost increases.¹⁵⁰

Staff notes that, in its 2025 SRSQ, Xcel has reported that vegetation continues to be the number one major cause of outage:

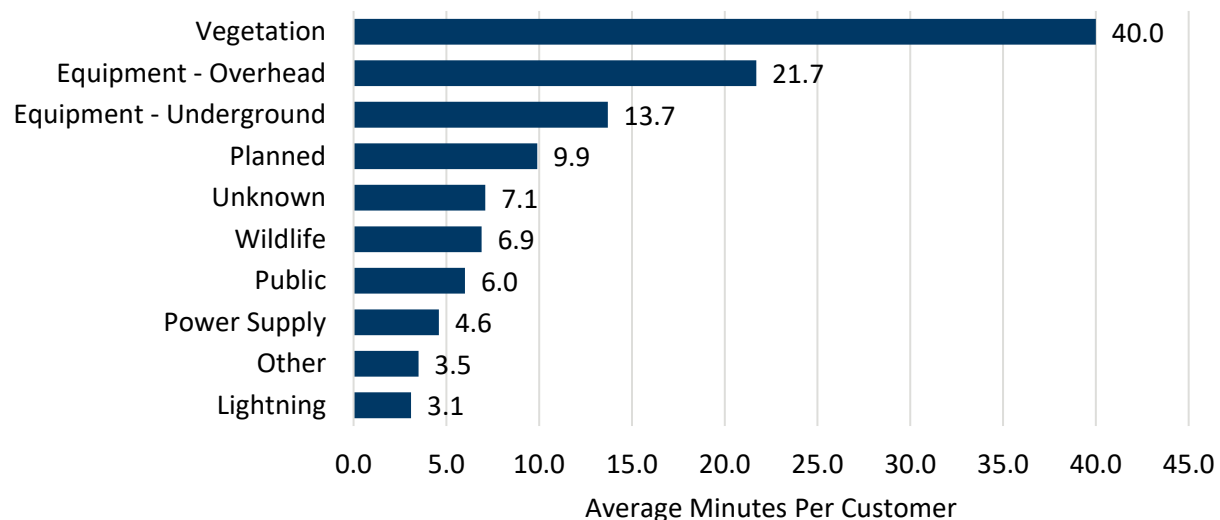
¹⁴⁷ 2024 SRSQ, Docket E002/M-25-27, Department 7-15-2025 Initial Comments, pp. 22. Note that “loaded labor” refers to total cost of invoicing including equipment, labor, materials, and taxes divided by total labor hours.

¹⁴⁸ 2024 SRSQ, Docket E002/M-25-27, Department 7-15-2025 Initial Comments, pp. 18-19.

¹⁴⁹ 2025 SRSQ, Department Initial Comments, pp. 18-23.

¹⁵⁰ Docket No. E002/GR-24-320, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, [Menson Direct 11-1-24](#), pp. 140 – 142 (PDF pp. 144-146)

Figure 24: Top Ten Outages Causes in 2025, According to 2025 SRSQ¹⁵¹



While targeted undergrounding is one way to address this, Staff is unclear why Xcel is prioritizing this so heavily over tree trimming around distribution lines, which appears to be a much cheaper way to mitigate this issue.

First: vegetation management is an affordable strategy with potentially high impact. The Department estimates that vegetation management costs approximately \$7,000 per mile,¹⁵² while Xcel estimates that targeted undergrounding could cost approximately \$1.5 million per mile.¹⁵³ Xcel says that one of targeted undergrounding’s advantages is that it “lowers operational costs by minimizing vegetation management,”¹⁵⁴ but those costs are relatively small in comparison to the large (and, according to the Department, potentially unreliable) costs projected for targeted undergrounding.

Xcel also lists reasons for vegetation management being challenging that Staff sees as similar, if not more pronounced, for targeted undergrounding. Xcel states in its petition that a primary challenge to vegetation management is that “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.”¹⁵⁵ However, Xcel would still retain overhead service drops and so the need to reach these locations would not disappear. It would also require major excavation and reconfiguring on these same properties.

¹⁵¹ Xcel Energy 2025 SRSQ, Docket E002/M-26-27, Initial Filing Part 2 of 3, Attachment I, p. 1 (PDF p. 73)

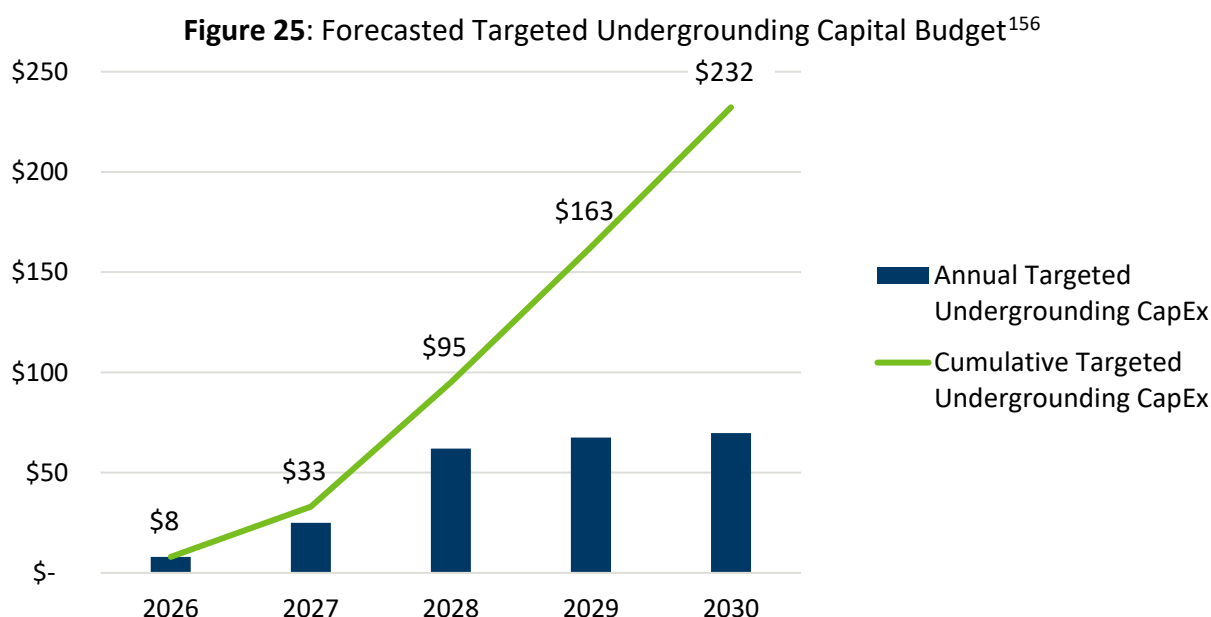
¹⁵² Department 2-27-26 Initial Comments, p. 83 (PDF p. 91).

¹⁵³ Department 2-27-26 Initial Comments, Attachment B, IR No. 47 (PDF p. 212).

¹⁵⁴ Xcel Integrated Distribution Plan, Chapter 2, p. 5 (PDF p. 137).

¹⁵⁵ Xcel Integrated Distribution Plan, Chapter 2, p. 12 (PDF p. 144).

While vegetation management does not achieve all the benefits that Xcel claims targeted undergrounding does, it seems strange to Staff that Xcel would largely disfavor a program that seems well worth it for the price in favor for one that is much more expensive without clear, proven benefits.



The Commission approved Xcel's initial targeted undergrounding budget (\$2.3 million in 2025 and \$6.7 million in 2026) in the Company's recent rate case. Therefore, Staff does not support **Decision Option 24**. However, according to the IDP forecast the undergrounding budget is expected to increase significantly starting in 2027, as depicted in Figure 25. Therefore, the Commission may wish to provide direction ahead of Xcel's next rate case filing on whether it wants to see additional analysis, potential alternatives, or results from the initial projects before authorizing hundreds of millions of additional ratepayer dollars. Staff believes that some combination of **Decision Options 25 through 30** would provide valuable information in future cost recovery proceedings.

E. Wildfire Mitigation

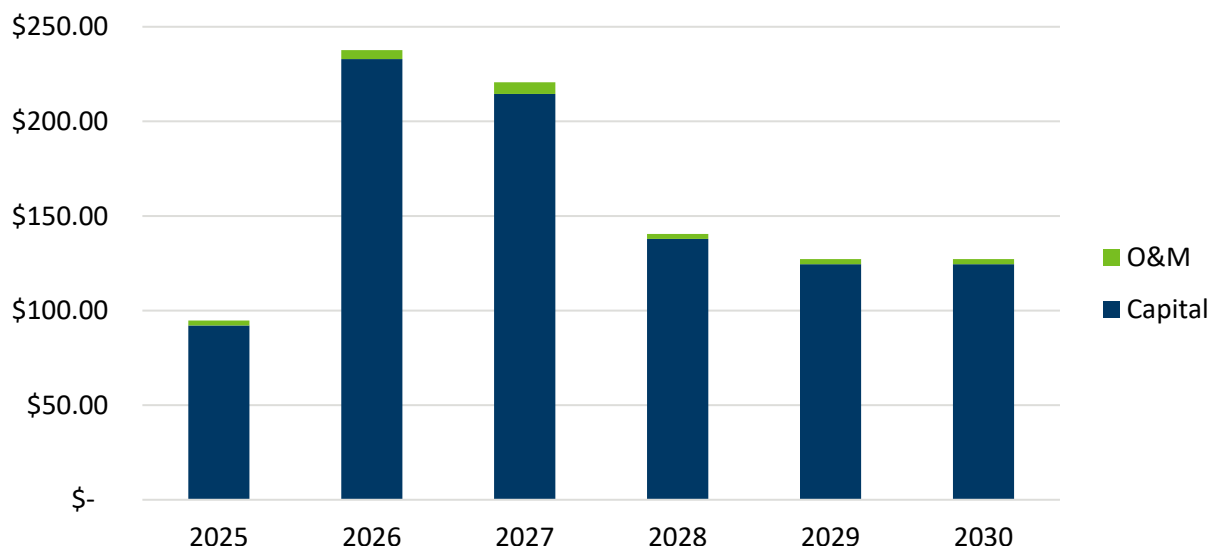
Xcel proposed in its petition to invest significant resources in wildfire mitigation.¹⁵⁷ Xcel has not addressed wildfire mitigation in previous IDPs, and so this is a new cost category and topic for discussion. Xcel stated that it plans to file an updated Wildfire Mitigation Plan that will reflect the final approved rate case budget and identify the specific tools and strategies that the Company will deploy.¹⁵⁸

¹⁵⁶ Xcel Integrated Distribution Plan, Attachment H

¹⁵⁷ Xcel Integrated Distribution Plan, Chapter 2, pp. 24 – 29 (PDF pp. 157-161)

¹⁵⁸ Department 2-27-26 Initial Comments, Attachment B, p.2, Information Request No. 95 (PDF p. 255).

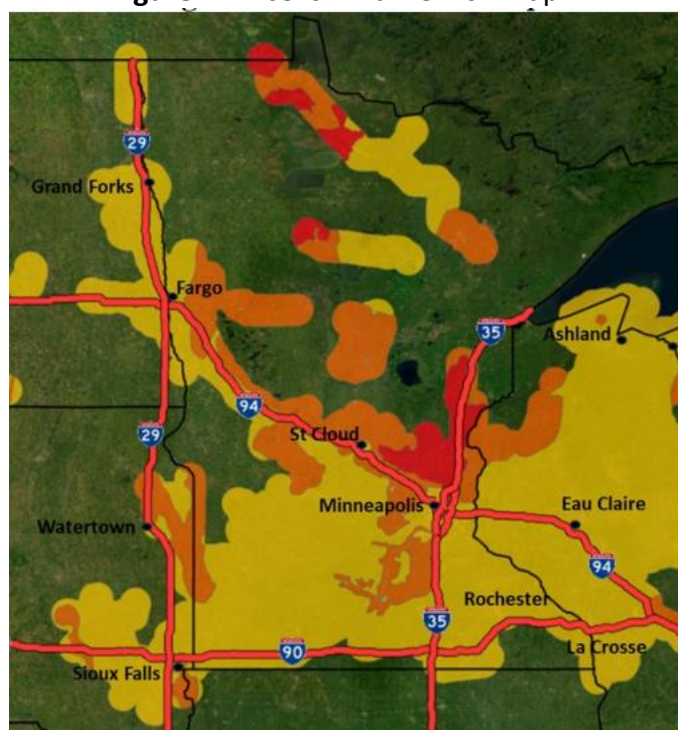
Figure 26: Xcel's Wildfire Mitigation Budget, 2025-2030 (\$ millions)¹⁵⁹



Xcel's wildfire mitigation budget was approved with some adjustments in the Company's recent rate case and Staff is awaiting the final order to determine how the modifications would change the plans outline in the IDP. However, for the purposes of the IDP, the information in these briefing papers provides an overview of the Company's various wildfire efforts. Staff anticipates that the Company's updated Wildfire Mitigation Plan will reflect the approved budget in the rate case.

Xcel provided a map of assessed wildfire risk across places in Minnesota where its transmission and/or distribution assets lie. Xcel stated that it identified 107,000 poles in Tier 2 (orange, "moderate risk") and 4,700 poles in Tier 3 (red, "high risk") and used that data to prioritize its proposed investments. The map incorporates data layers such as vegetation type, historical fire data, topography, and infrastructure density.

¹⁵⁹ Xcel Integrated Distribution Plan, Chapter 2, Table 2-3, p. 29 (PDF p. 161). Represents the most current wildfire expenditures as reflected in the Company's initial 2024 rate case testimony. These figures differ slightly from the wildfire allocations in the five-year capital budget presented in Chapter 6 because they were captured at different points in time.

Figure 27: Xcel's Wildfire Risk Map¹⁶⁰

Xcel named vegetation contact as the leading cause of utility-related wildfires.¹⁶¹ To mitigate these issues, Xcel stated that it uses the following strategies:

Table 7: Wildfire Mitigation Strategies

	Strategy	Description
Vegetation Management	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.
Situational Awareness	Advanced Fire Modeling Software (FireSight)	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.

¹⁶⁰ Xcel Integrated Distribution Plan, Chapter 2, p. 26 (PDF p. 158).

¹⁶¹ Xcel Integrated Distribution Plan, Chapter 2, p. 28 (PDF p. 160).

	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.
Resiliency Strategies ¹⁶²	Asset Inspection and Repair/Replacement	Includes drone-assisted inspections and manual assessments to identify and remediate defects. Xcel stated that it would inspect all Tier 3 poles every three years, and all Tier 2 poles every six years. ¹⁶³
	Pole Loading & Clearance (PL&C)	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.
Operational Mitigations	Enhanced Powerline Safety Settings (EPSS)	Modifies protection schemes to detect faults more quickly and block automatic reclosing.
	Public Safety Power Shutoffs (PSPS)	Temporarily de-energizes lines in extreme fire weather conditions to prevent ignition.
Distribution System Upgrades ¹⁶⁴	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

The Department and ELPC/CEF/VS questioned the cost and level of detail provided of Xcel's wildfire mitigation plan. Although ELPC/CEF/VS stated that they believed wildfire mitigation to

¹⁶² Department 2-27-26 Initial Comments, Attachment B – DOC IR 91. Xcel clarified that, unlike traditional resiliency efforts, these would be focused on areas of heightened wildfire risk.

¹⁶³ Department 2-27-26 Initial Comments, Attachment B – DOC IR 91.

¹⁶⁴ Department 2-27-26 Initial Comments, pp. 71-73. Xcel stated that it is proactively making distribution system upgrades within in wildfire mitigation plan rather than only performing routine asset renewal.

be important, “we suggest that such a high-budget, substantial program necessitates a more detailed description of the Company’s strategy and decision-making” than what was provided.¹⁶⁵ Both parties made connections between concerns submitted in the rate case and in this docket.¹⁶⁶

The Department critiqued Xcel’s Wildfire Mitigation Plan as an example of the Company attempting to circumvent the IDP process by submitting the WMP for cost recovery through a rate case instead of first filing the plan in the IDP prior to seeking cost recovery.¹⁶⁷ The Department argued that Xcel’s requested wildfire budget did not establish individual project benefits and that the benefits and risks are not quantified.

The Department argued that “while utilities cannot be required to submit their plans for future cost recovery requests in the IDP before cost recovery can be approved, the exclusion of feasible alternatives or appropriate sensitivity analysis in a cost recovery proceeding can be used to justify that proposed spending is imprudent.”¹⁶⁸

As for the AI-powered Firesight tool, the Department noted that it had asked if Xcel had completed any studies within its Minnesota territory to determine the effectiveness of its proposed AI cameras in detecting smoke or fire signatures. The Department also asked Xcel to propose reporting metrics for its proposed AI camera project. Xcel responded that it has not completed any studies within its Minnesota territory to demonstrate the effectiveness of its proposed cameras.¹⁶⁹

Ultimately, the Department concluded that “the information included in the IDP and gathered through Department IRs does not constitute a robust plan that is fully optimized. Furthermore, it is unclear what issue(s) Xcel’s wildfire mitigation plan is trying to address.”¹⁷⁰

The Department and ELPC/CEF/VS jointly recommended, and Xcel mostly agreed, that the Commission require Xcel to file its intended Wildfire Mitigation Plan alongside future IDPs when they are outside of rate cases, and to include the following information:

- A description of the intent of the Company in mitigating wildfire risk (i.e. mitigating utility-caused wildfires/minimizing liability or mitigating fire damage to utility assets).
- A definition of “wildfire” as it is used for utility identification, planning and mitigation.
- A discussion of its risk modelling, mapping and prioritization process within its Wildfire Mitigation Plan.
- Quantification of actual wildfire risk in Xcel’s territory based on the probability and size of a fire, and land use.
- Xcel’s Minnesota wildfire risk should be compared to other reliability and safety risks

¹⁶⁵ ELPC/CEF/VS 2-26-26 Initial Comments, p. 49.

¹⁶⁶ ELPC/CEF/VS 2-26-26 Initial Comments, p. 49.

¹⁶⁷ Department 2-27-26 Initial Comments, pp. 17-18.

¹⁶⁸ Department 2-27-26 Initial Comments, p. 18.

¹⁶⁹ Department 2-27-26 Initial Comments, p. 71.

¹⁷⁰ Department 2-27-26 Initial Comments, p. 71.



experienced by Xcel in Minnesota as well as the wildfire risk experienced in Xcel's other jurisdictions.

- Quantification of wildfire damages by event size, including Xcel-owned and other property damage, applicable liability, and any other costs Xcel deems reasonable to include.
- The most recent version of its wildfire risk map with a narrative explanation of the highest risk areas, and any changes from the last iteration of the Wildfire Mitigation Plan.
- Reporting on the number and locations of wildfires experienced in its territory, the number of outages caused by wildfire, and the average length of wildfire-related outages.
- Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the rate-case-approved wildfire mitigation measures, wildfire-related outages in Xcel's territory decreased 50 percent; the number of wildfires in Xcel's service territory decreased from 100 to 50 since the filing of the Company's last IDP resulting in approximately 10 fewer outages)
- Discussion of its use of its Public Safety Power Shutoff Program, including the number of PSPS outages, cause of the PSPS outage, average length of a PSPS outage, if/how notice was provided to customers, and measures the Company employs to protect customers that are medically dependent on electric service.
- The Wildfire Safety Operations Playbook, the PSPS Playbook, and the PSPS Communications Playbook as attachments or provide the location where the Playbooks can be accessed.
- A full cost benefit analysis of any proposals.¹⁷¹

(Decision Option 32 and 33)

The Department recommended that the Commission require Xcel to discuss and provide the available years of wildfire-related outage data in its Wildfire Mitigation Plan, as the Company was not sure how many years of data it would be able to provide (**Decision Option 33.m**).

The Department also expressed concern that the wildfire mitigation plan did not integrate information about its customers with medically necessary equipment, and recommended that Xcel integrate the locational information from its medically necessary equipment certification form into its wildfire mitigation plan (**Decision Option 33.n**).¹⁷² Xcel objected, stating that "this information is already integrated into internal efforts but cannot be shared publicly due to customer privacy restrictions."¹⁷³

Finally, the Department requested that the Commission authorize it to spend up to \$300,000 to obtain contractual services for wildfire mitigation plan reviews, as "an outside contractor would

¹⁷¹ Department Reply Comments, pp. 82-83.

¹⁷² Department 2-27-26 Initial Comments, p. 70.

¹⁷³ Xcel 3-19-26 Reply Comments, Attachment A, p. 26 (PDF p. 34).

bring additional insight and WMP expertise that is not currently housed within the Department.”¹⁷⁴ (**Decision Option 34**)

Xcel agreed to the cadence and most of the elements of the Department’s Wildfire Mitigation Plan (**Decision Option 33.a-k**). However, Xcel opposed a full cost benefit analysis (**Decision Option DEPT 33.I**):

[T]he Company does not support evaluating all wildfire mitigation measures—or developing wildfire mitigation portfolios—exclusively through CBAs or cost benefit ratios (CBRs). In particular, the Company does not plan to develop CBRs for foundational or control type programs that are designed to maintain risk at current or acceptable levels (such as vegetation management), as these programs are compliance-driven or infeasible to model with available data. Further, many key benefits—such as reducing ignition risk, protecting medically vulnerable customers, and avoiding catastrophic losses—are difficult to quantify and often rely on incomplete historical data.¹⁷⁵

1. Staff Analysis

As Xcel’s initial wildfire budget was approved for 2025 and 2026 in its recent rate case, the Commission does not need to take any action on spending levels in the IDP. The main issue in the present proceeding is whether to require Xcel to file a Wildfire Mitigation Plan (WMP), and if so, the contents of the plan, a due date, and in what docket it should be filed. As discussed in the Joint Briefing Papers, Staff recommends that WMPs be filed in a new, separate proceeding with a due date to be determined in consultation with utilities and stakeholders to avoid other major filings (**Decision Option 31**).

In regard to the contents of Xcel’s WMP, Staff believes that the Department and Xcel are largely in alignment on **Decision Option 33** with the exception of two items:

- Subpart l. A full cost benefit analysis of any proposals
- Subpart n. An integration of the locational information from its medically necessary equipment certification form into its wildfire mitigation plan.

In regards to cost benefit analysis, Staff refers the Commission to its analysis in Section C.2.iv. As noted there, Staff’s position is that CBAs outside of a cost recovery proceeding provide limited value. Staff believes a decision on what kind of economic analysis to file with WMPs is better deferred to the consideration of the first plan.

Staff understands the Department’s concern about medically vulnerable customers during wildfire-related outages and believes that it is reasonable for Xcel to have to demonstrate steps for protecting medically vulnerable residential customers. However, Staff does not believe Xcel must necessarily include locational information (which may be sensitive) in map form. Alternatively, Staff recommends that Xcel provides the number of customers with medically

¹⁷⁴ Department Reply Comments, p. 43.

¹⁷⁵ Xcel 3-19-26 Reply Comments, Attachment A, p. 27 (PDF p. 35).

necessary equipment certification forms in its WMP, and steps it will take to mitigate damage from outages before, during, and after wildfire-related damage may occur (**Decision Option 33.o**).

Finally, as summarized in the Joint Briefing Papers, the Department requested authorization under Minn. Stat. § 216B.62, subd. 8 for technical assistance in the review of utility WMPs (**Decision Option 34**).

F. Changes to Distribution Planning Process

1. Planning Standards Review Process

The Department's comments focused on the changes to Xcel's distribution planning process and budget since the Commission initiated the IDP filing requirements in 2018. The Department stated that while it supported the five planning objectives set forth by the Commission for the IDPs, it did not fully support how the objectives were operationalized and advocated for updating the IDP process to better align with other proceedings. It reasoned that since the sources of budget growth in Xcel's IDP had shifted from grid modernization projects to "more fundamental and fell into mandatory spending categories," new approaches were needed to address Xcel's budget beyond the traditional IDP filing requirements.¹⁷⁶

The Department noted that distribution spending had risen from 18–19% of capital expenditures (capex) in 2020–2021 to 30% in 2024, with higher levels of spending projected through 2030. The Department contended that there was no secondary process to ensure that Xcel optimized its distribution spending, as there was in an Integrated Resource Plan (IRP) or in the MISO transmission planning process. It reasoned that Xcel's distribution spending increases were a cause for greater scrutiny into the appropriateness and optimal usage of the distribution expenditures.¹⁷⁷

The Department claimed that the distribution system currently lacked "optimization" which it described as "every asset on Xcel's distribution system was used to its fullest potential, taking into consideration the maximization of ratepayer value in the process."¹⁷⁸ The Department provided example that reflected its concerns with Xcel's distribution planning processes:

- If Xcel replaces an asset before the end of its useful life and the asset could have been used another year, or two, or five without major consequences, the asset replacement is not optimized.
- If Xcel sizes a conductor to a ten-year forecast, which then requires a reconductor in year eleven, the conductor sizing is not optimized.
- If Xcel replaces an asset based on a capacity forecast that is biased, the asset replacement is not optimized.

¹⁷⁶ Department 2-26-26 Initial Comments, pp. 6-7.

¹⁷⁷ Department 2-26-26 Initial Comments, pp. 8-9.

¹⁷⁸ Department 2-26-26 Initial Comments, p. 13.

- If Xcel installs wildfire mitigations based on a risk assessment that is too high, the system is not optimized.
- If Xcel assumes blanket benefits for programmatic spending that vary widely by individual project, the program is not optimized.

The Department cautioned that it did not seek to turn IDPs into “pre-rate cases,” as rate cases were for determining prudence, not optimization. The Department differentiated the two by explaining that the examination of system alternatives should be conducted in an IDP, rather than in a rate case as the IDP is “the appropriate venue to explore alternative strategies before a utility makes a cost recovery request.”¹⁷⁹

Furthermore, the Department asserted that an analysis of alternative investments and planning standards advances the optimization considerations and the cost-benefit considerations, in line with IDP planning objectives 4 and 5.¹⁸⁰

The Department described planned net loading, non-wires alternatives analysis, and cost-benefit analysis of certain distribution programs as examples of current optimization efforts in the distribution system.

In addition, the Department pushed for more quantitative analyses on Xcel’s part as opposed to the qualitative analyses present in the IDP, stating that “only in cases where the outcome was obvious and indisputable should Xcel forgo any type of quantitative analysis.”

The Department proposed a new “Planning Standards Review Process (PSRP)” whereby stakeholders would, in conjunction with Xcel’s engineers, “weigh the costs and benefits of Xcel’s capacity planning standards regarding cost and the increased risk of outages.”¹⁸¹ The new PSRP would occur over an eight-year cycle, with one portion of the Company’s planning standards undergoing review every two years in conjunction with the IDP process:

- 2027: Capacity
- 2029: Reliability and Asset Health
- 2031: Grid Modernization, Distributed Energy Resources, and Operation and Maintenance
- 2033: Budgeting

The Planning Standards Review Process would proceed through the following steps

1. The Company and stakeholders would identify the main system planning standards that Xcel uses for that cycle’s review topic (Capacity, Reliability and Asset Health, Grid Mod, DERs, and O&M, Budgeting).
2. Xcel and stakeholders would select one or more planning standards to review before the next IDP.

¹⁷⁹ Department 2-26-26 Initial Comments, pp. 10-11.

¹⁸⁰ Department 2-26-26 Initial Comments, pp. 12-13.

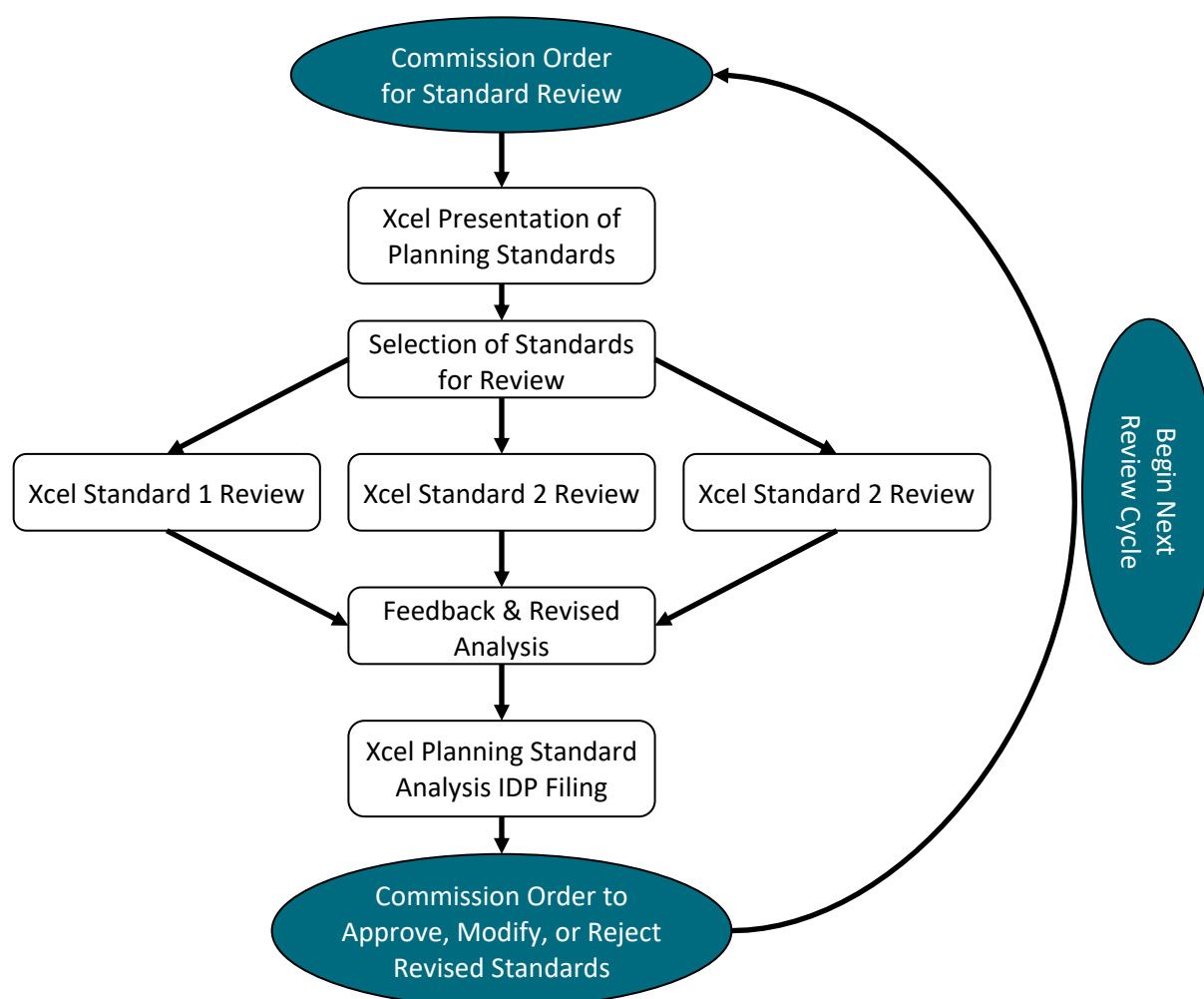
¹⁸¹ Department 2-26-26 Initial Comments, p. 23.

3. Xcel and stakeholders would select alternatives to the existing planning standards to analyze.
4. Xcel would perform a quantitative analysis of the existing and alternative system planning standards that measure the estimated costs and benefits.
5. Xcel would present the results of steps the analysis in its next IDP.
6. In its notice for comment on the IDP, the Commission would include a question on whether it should approve, modify, or reject the alternative planning standard.

Decision Options 35 and 36 establish the PSRP.

The Department provided the following diagram depicting how the PSRP would work.

Figure 28: Department Summary of Planning Standard Review and Approval Process¹⁸²



The Department also recommended requiring Xcel to file any changes to its planning standards in the IDP (**Decision Option 37**)

¹⁸² Department 2-27-26 Initial Comments, Figure 9, p. 24.

Because issues with a planning standard may emerge outside of the planned review cycle, the Department also recommended establishing an ad hoc planning review process. The Department suggested limiting any ad hoc reviews to once per IDP cycle to limit the burden on Xcel and stakeholders (**Decision Option 38**).¹⁸³

The Department explained that being able to obtain engineering services would assist in its review of Xcel's planning standards and reduce strain on the Company's engineers. Therefore, it requested the Commission authorize the Department to spend up to \$1 million over the next two years to obtain contractual services for planning standard review.¹⁸⁴ The Department also requested an additional \$175,000 to hire a third-party facilitator to run the process (**Decision Option 39**).¹⁸⁵

Xcel did not support the Department's recommendation to establish recurring or ad hoc processes for parties to review planning standards or require CBAs of alternative standards. The Company noted that these processes could "blur the line between regulatory oversight and technical system design, expand the scope of the IDP beyond its intended purpose, and introduce uncertainty that could delay necessary investments."¹⁸⁶ Xcel noted that planning processes mandated by the Commission could shift engineering judgment away from the Company and limit the flexibility of standards.¹⁸⁷

Xcel did support the Department's recommendation to disclose all changes to its system planning standards in the IDP as long as it is not required to release proprietary or confidential information.

Multiple stakeholders support the Department's proposed PSRP in Reply Comments including JSP, ELPC/VS/CEF, Fresh Energy, the OAG, CUB, and Minneapolis.

The JSP emphasized the upward trajectory of Xcel's capacity budget, agreeing with the Department that absent an "optimization" process similar to an IRP or MISO's LRTP there is not sufficient scrutiny of the Company's distribution costs. The JSP explained the PSRP would be "fully consistent with the informational purpose of the IDP."¹⁸⁸

ELPC/CEF/VS explained that the Department's PSRP aligned with its recommendations to examine Xcel's N-1 contingency planning and use of emergency ratings. They disagreed with Xcel's assertion that the Commission cannot review or order adjustments to the Company's

¹⁸³ Department, 4-23-2026 Reply Comments, p. 11

¹⁸⁴ Department, 4-23-2026 Reply Comments, p. 13

¹⁸⁵ Department response to PUC IR6

¹⁸⁶ Xcel 3-19-26 Reply Comments, p. 4 (PDF p. 5).

¹⁸⁷ Xcel 3-19-26 Reply Comments, Attachment A, pp. 5-6 (PDF pp. 13-14).

¹⁸⁸ JSP 4-23-26 Reply Comments, pp. 3-4.

planning standards through the IDP process. ELPC/VS/CEF stated the engineering-based judgements that make up Xcel's planning standards still must be prudent overall.¹⁸⁹

Fresh Energy supported the PSRP, but not the additional ad hoc review process (**Decision Option 38**), stating it could become burdensome in addition to the extension working group already outlined.¹⁹⁰

CUB acknowledged that the Department's PSRP would "fundamentally alter the scope of the IDP" but that it was necessary given the rapid increase in distribution expenditures. CUB emphasized the need for a venue to consider a range of options for distribution investments and planning standards rather than the default option proposed by the utility.¹⁹¹

The OAG echoed other stakeholders, stating that on its current trajectory, the Company's distribution spending would worsen the affordability crisis. In the OAG's estimation, the PSRP would ensure that distribution investments were maximized to their fullest value, especially as the Company expects to see increase load growth.¹⁹²

Minneapolis also supported the PSRP, highlighting its appreciation of how equity is incorporated into the process.¹⁹³

2. Review of Capacity Planning Standards

The Department recommended that the first iteration of its PSRP focus on planning standards that relate to Xcel's Capacity budget (**Decision Option 40**) Fresh Energy and ELPC/CEF/VS also provided feedback on Xcel's risk analysis criteria. Figure 29 depicts Xcel's historic and forecasted capacity budget.

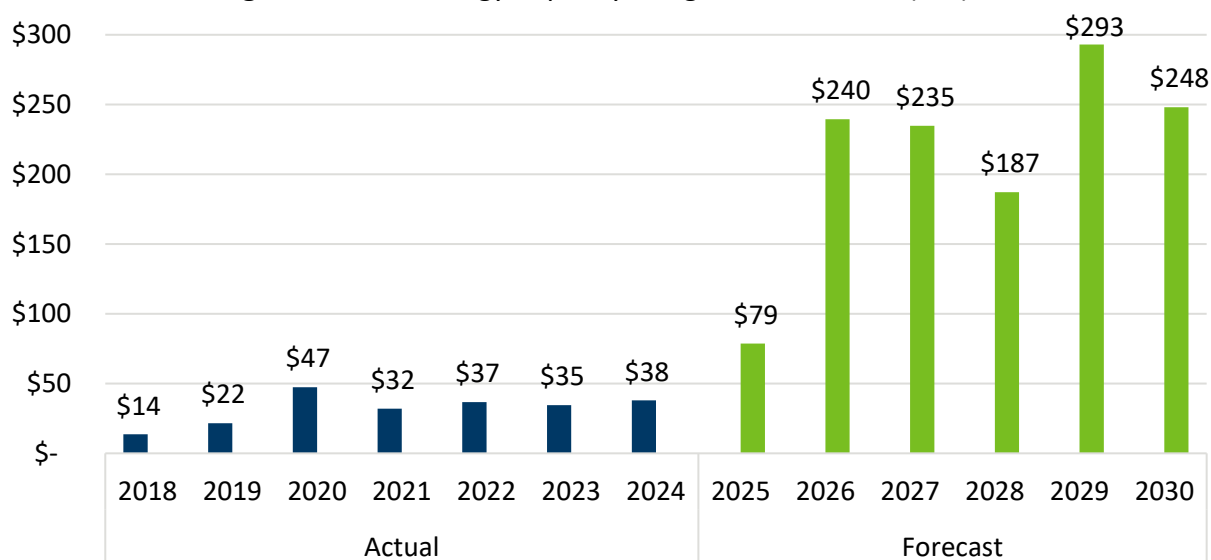
¹⁸⁹ ELPC/CEF/VS 4-23-26 Reply Comments, p. 11-13.

¹⁹⁰ Fresh Energy 4-23-26 Reply Comments, p. 6.

¹⁹¹ CUB 4-23-26 Reply Comments, p. 3.

¹⁹² OAG 4-23-2026 Reply Comments, p. 5

¹⁹³ Minneapolis 4-23-2026 Reply Comments, p. 3

Figure 29: Xcel Energy Capacity Budget, 2018 – 2030 (\$M)¹⁹⁴

The Department raised concerns regarding Xcel’s capacity budget increase, which is predicted to rise from a total of \$240 million between 2019-2024 to \$1.21 billion between 2025-2030. The Department indicated it understood the primary driver of increased spending to be attributable to peak load growth.¹⁹⁵

The Department claimed that Xcel’s capacity planning standards may be overly conservative and therefore result in an inflated budget. On pages 51 through 65 of its February 26, 2026 Initial Comments the Department analyzed various hypothetical changes to Xcel’s capacity planning standards that could result in a lower overall budget. Due to the level of detail involved, Staff refers Commissioners to the full comments for the in-depth analysis.

The Department focused its analysis on an economic evaluation of Xcel’s capacity planning standards, and based on that analysis, indicated the Commission should examine the following topics as part of its proposed PSRP.

- Capacity forecasting and accuracy:
- N-0 thresholds margin and the use of AMI or other actual data
- N-1 probability of coincident peak load and N-1 contingencies
- N-1 screening based on cost effectiveness
- Sizing new assets for future load growth
- Capacity Risk Framework
- Project Prioritization

The Department also clarified that the discussion requires more data and analysis than can be provided in these comments and advocated for additional analysis to take place as part of the proposed PSRP.

¹⁹⁴ Using Xcel Energy’s internal budget categories

¹⁹⁵ Department 2-26-26 Initial Comments, pp. 49-50.

Fresh Energy also focused on Xcel's Risk Scoring Framework, which the Company uses to assess which areas of the grid have the highest risk of an overload and need a capacity upgrade. Fresh Energy disagreed with Xcel's assumption from its Risk Scoring Framework for capacity expenditures stating that an equipment overload occurrence under normal (N-0) conditions directly results in customer outages. Fresh Energy asked Xcel to explain the concept of an overload customer minutes out (CMO) and its application in the Risk Scoring Framework in reply comments.¹⁹⁶

ELPC/CEF/VS similarly expressed concerns about Xcel's risk analysis, specific that it identifies N-1 scenarios and contingency projects that are not justified or necessary for system reliability.¹⁹⁷ They explained that since N-1 scenarios are contingency risks unlike N-0 overloads, the former are less likely to occur in a given year, and the combined likelihood of such scenarios happening during peak load periods is even lower. This means that such probability-adjusted customer outage impact calculations often have cost-benefit ratios lower than 1.

ELPC/CEF/VS suggested that Xcel's N-1 scenario might overestimate the risk of customer outages, measured as Customer Minutes Out (CMO). Xcel limits its planning criteria to normal capacity ratings but allows system operators during operations to run equipment to higher emergency ratings. However, ELPC/CEF/VS' understanding is that Xcel's system planning does not account for emergency ratings for N-1 conditions. Therefore, ELPC/CEF/VS recommended directing Xcel to engage with stakeholders on improvements to its risk analysis, and reply comments stated this recommendation aligned with the Department's proposed PSRP.

Xcel did not support the recommendations from parties to review and modify its capacity planning standards for inclusion in the 2027 IDP.¹⁹⁸ Xcel asserted that its planning standards are grounded in engineering science and judgment and that changes to the standards would introduce uncertainty into system planning, especially around whether current system design standards would stay in effect long enough for newly built infrastructure to remain viable under future planning criteria.¹⁹⁹ Moreover, Xcel stated that revising the capacity planning standards, N-0 and N-1 risk analysis methodologies, asset sizing, and prioritization standards would be resource-intensive while not guaranteeing benefits to the IDP and planning process.

3. *Prioritization Criteria*

In addition to recommendations on Xcel's risk analysis, ELPC/CEF/VS reiterated its position that the Commission should require the Company to integrate equity considerations into its prioritization process for selecting capital investments. They noted that while they have made this recommendation before, recent examples from DTE and Consumers Energy in Michigan provide a more concrete roadmap of how Xcel could add additional criteria to ensure that

¹⁹⁶ Fresh Energy, 2-26-26 Initial Comments, p. 8

¹⁹⁷ Xcel 2025 Integrated Distribution Plan, Chapter 1, pp. 30-31 (PDF pp. 65-66).

¹⁹⁸ Xcel 3-19-26 Reply Comments, Attachment A, pp. 4-5 (PDF pp. 12-13).

¹⁹⁹ Xcel 3-19-26 Reply Comments, Attachment A, pp. 3-4 (PDF pp. 11-12).

distribution investments are spread equitably throughout the Company's service territory (**Decision Options 46 and 23**).²⁰⁰

4. *Staff Analysis*

All commenters supporting the Department's proposed PSRP shared a common concern: the rapid increase of Xcel's distribution budget over the past decade and its impact on affordability and how overly conservative planning standards could be driving higher costs. Staff shares the same concern but is skeptical that adding an expensive and time intensive process to the IDP will effectively address rising distribution capital expenditures. Instead, Staff favors alternatives that will be less procedurally burdensome and enhance the review of distribution expenditures through existing proceedings, with a focus on the general rate case. Staff proposes the following alternatives and expands on each below:

- Refining and adding filing requirements about forecasting, scenario analysis, and historical peak load data.
- Requiring forecast support for large, discrete capacity investments in a cost recovery proceeding, similar to required forecast support for projects submitted through the Proactive Upgrade Proposal (PUP) framework.
- A series of technical workshops, facilitated by Commission Staff with potential support from the National Labs, that focuses on topics from the Department's proposed review of Xcel's capacity standards.
- An independent review of Xcel's engineering standards.
- One or more joint stakeholder meetings with the DGWG, the DSRUP Workgroup, and the Proactive Workgroup to discuss the prioritization process and criteria for Xcel's discrete distribution capital investment projects.

These alternatives specifically respond to the recommendations around PSRP and the Capacity Standards review, but Staff notes that recommendations from the Cost-Benefit Analysis, Forecasting, Reliability, and Budget Overview sections will also contribute to overall cost containment of distribution expenditures.

Given the scope, time commitment, and potential cost of the Department's proposed Planning Standards Review Process (PSRP), Staff reached out to Lawrence Berkley National Laboratory's (LBNL) State Technical Assistance Program²⁰¹ to write a technical memo evaluating how other state utility commissions engage with utility distribution standards. The full memo is filed as Attachment A to these briefing papers. LBNL's memo forms the basis of Staff's recommendations. Staff specifically requested assistance on the following topics:

1. Utility Planning and Design Standards
 - A. Are there any state utility commissions that engage in the review and approval of specific planning standards for utility distribution systems, including approval of engineering standards? Are those proceedings or standards published anywhere?

²⁰⁰ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 42-46.

²⁰¹ <https://emp.lbl.gov/projects/state-TA-program>



- B. Are there any national entities that issue or develop "planning standards" for utilities?
- C. Is there a widely used definition of "good engineering judgment" as it pertains to the electric system?
- 2. Review the DOC's proposed capacity planning standards and provide examples from other jurisdictions
- 3. Alternative to forming a working group to assess Xcel Energy's engineering standards and decision-making practices
- 4. Best practices for assessing a utility's forecasted vs. actual distribution system spending outside of a rate case

There does not seem to be any disagreement between Xcel and stakeholders that understanding and examining Xcel's planning process and standards in more depth can lead to better outcomes in regulatory proceedings. Indeed, Xcel did not oppose the Department's recommendation to file updates to the Company's planning standards with the Commission. Staff also supports ensuring Xcel's planning standards align with industry best practices and are not overly conservative. As explained in the LBNL memo, multiple Commissions engage with utility engineering standards through regulatory proceedings without explicitly approving or designing engineering standards themselves.²⁰² Staff believes this approach is the appropriate path for the Minnesota Commission.

Staff highlights a portion of the LBNL memo that proposes a potential path for the Commission's engagement with planning standards:

First, when utility engineers select capacity planning parameters such as a target feeder utilization of 65–70% for N-1 switching reserve, or a worst-case peak load scenario for N-0 rating, those choices are made under the professional signature and certification of a licensed PE, who is personally accountable to the Minnesota Board of Architecture, Engineering, Land Surveying, Landscape Architecture, Geoscience, and Interior Design for the soundness of those judgments. The PE is required by law to exercise independent professional judgment; a review of whether that judgment is reasonable and cost-effective is not an intrusion on engineering discretion, but a public interest check on its outcomes.

Second, the PE standard of care "*consistent with generally accepted scientific and engineering principles and all available relevant information*" ([40 CFR 59.680](#)) is not static. As industry practices evolve (e.g., with dynamic line ratings, probabilistic load forecasting, and GER-aware planning tools), the body of "generally accepted" principles continues to expand. The Commission could assess whether utility-licensed engineers are applying current best practices or relying on conservative legacy standards that may no longer reflect what a competent PE working in today's environment would reasonably adopt.

....

The Commission could assess whether utilities' choices within acceptable ranges of planning parameters are justified, cost-effective, and consistent with current industry practice — a

²⁰² Technical Memo for Minnesota Public Utilities Commission Staff Distribution Planning and Design Standards ("LBNL Memo"), Lawrence Berkley National Lab, June 12, 2026, pp. 2-5

reasonable regulatory function that the evidence above suggests is increasingly being pursued in leading jurisdictions.²⁰³

What Staff sees as the major sticking point is the portion of PSRP that would focus on the economic comparison and evaluation of various standards. This is the portion that concerns Staff the most, because it could unintentionally result in decisions that degrade reliability, especially for underserved communities that already have disparate outage rates, in exchange for monetary savings. As noted above, cost-benefit analysis is subjective and not a guarantee of future savings. An additional concern is the lack of enforcement mechanism included in the Department's recommended process. When Staff questioned the Department on what mechanisms the Commission should use to assess enforce compliance and determine the effectiveness of any approved standards, the Department responded that "no additional regulatory proceedings or mechanisms are necessary beyond the existing IDP docket."²⁰⁴

Capacity Forecasting and Accuracy Recommendation

The LBNL memo explains "forecast accuracy encompasses two interrelated issues: (1) predicting future gross load growth (load forecasting), and (2) netting out the impact of behind-the-meter DG, primarily solar PV and flexible loads, to determine the net peak demand for distribution infrastructure." Fortunately, the Commission has addressed Planned Net Load over several IDP review cycles. For the longer-term load forecast LBNL suggests "the Commission could require a utility to report historical forecast accuracy, specifically the mean absolute percentage error of its feeder and substation-level peak load forecasts relative to actual outcomes."²⁰⁵

As noted in the forecasting section, Staff agrees that it is important to track the long-term accuracy of Xcel's LoadSEER forecast. This should be a relatively straightforward process that can be worked out through the IDP Improvement Workgroup by consulting with Xcel on the best way for the Company to report actual historical load in future IDPs. This seems to be a simple matter of data collection and reporting and not an actual "planning standard" that necessitates review. (**Decision Option 5.a**).

In Xcel's recently concluded rate case, the Joint Intervenors, which includes ELPC/CEF/VS, attempted to scrutinize Xcel's discrete capacity investments, which totaled \$231.6 million in capital additions in 2025 and 2026. Witness Kenworthy stated that "the budget for capacity is established using a risk-versus-cost methodology and "specific scope of work," rather than a demonstration that each project's need and timing were stress-tested against alternatives."²⁰⁶ While the Joint Intervenors ultimately did not dispute the discrete capacity budget in the 2024 rate case, they did emphasize the need to scrutinize the forecasts and least cost alternatives to discrete capacity projects through both the IDP and future rate cases.²⁰⁷

²⁰³ LBNL Memo, p. 9

²⁰⁴ Department response to Staff IR 1, 5-18-2026.

²⁰⁵ LBNL Memo, pp. 9-10

²⁰⁶ Kenworthy Direct, Docket E002/GR-24-320, pp. 23-24.

²⁰⁷

Staff suggests two potential paths to better scrutinize the necessity of large, capital investments driven by capacity needs. First, the Commission could require the Company to provide additional evidence in rate case proceedings to prove the need for the project in the form of forecast data for each project. Staff recommends this as an initial step given the Company should already possess this information from the analysis triggering the upgrade (**Decision Option 41**).

A second, more involved option would be to adopt some elements of the Proactive Grid Upgrade Framework for large discrete capacity projects in the zero-to-five-year time horizon, but without the cost share element. Using a more streamlined version of the Upgrade Framework would allow for a better alternatives analysis than currently exists in the rate case. Staff suggests this could also absorb the NWA process as a portion of the alternatives analysis. An added bonus would be that Xcel could better examine whether a utility installed NWA could meet some or all of the capacity needs if there is not sufficient interest from third party developers. If the Commission is interested in exploring this idea further, Staff could lead a discussion on its potential as part of Phase 2 of the Proactive Grid Upgrade Workgroup (**Decision Option 42**).

Engineering and risk-based topics recommendation

The LBNL Memo provided an assessment of the various engineering topics the Department proposed for the first iteration of the PSRP. Staff excerpts here the summary assessment for each topic.

- N-0 forecast uncertainty margin and the use of AMI or other actual data
 - Summary Assessment: A viable topic for consideration. The critical planning question is what load level the utility uses to trigger a capacity upgrade, rather than the physical rating ceiling.
- N-1 probability of coincident peak load and N-1 contingencies
 - Summary Assessment: The proposed framing conflates two distinct planning problems. The Commission could redirect attention to underlying questions about N-1 switching reserve.
- N-1 screening based on cost effectiveness
 - Summary Assessment: The framing could be revised from “screening” to benefit-cost analysis of N-1 switching investments, a productive and tractable area for Commission review.
- Equipment ratings during N-1 emergencies
 - Summary Assessment: Physical limits are non-negotiable. Commission review could focus on protocols and documentation for emergency rating use.
- Sizing new assets for future load growth
 - Summary Assessment: Equipment standardization practices constrain sizing flexibility. Commission review could focus on the load growth forecast that drives equipment sizing decisions, rather than the sizing convention itself.
- Capacity Risk Framework
 - Summary Assessment: This is the most conceptually open-ended of the eight proposed standards. It maps to portfolio-level risk management under uncertainty,

particularly related to load growth and GER adoption, a growing area of state regulatory interest.

Multiple commenters raised concerns about Xcel's risk analysis for N-1 contingencies being overly conservative and potentially triggering unnecessary upgrades. The LBNL memo suggests an alternative to the stakeholder process could be an independent review of Xcel's engineering standards to ensure they are in line with current planning guidelines.²⁰⁸ Staff believes this is a better alternative than the PSRP to review any engineering standards that may be overly conservative. An independent review would not require stakeholder time, could be accomplished on a known timeline, and would be grounded in engineering practices. Staff recommends requiring Xcel to work with Commission Staff to determine which standards should be reviewed and how to format the report. Staff would use the record developed in the current proceeding along with the LBNL memo and potentially additional national lab support to inform the scope of the independent engineering review. **(Decision Option 43)**.

Staff also recommends a recommends one or more technical workshops that addresses regulatory considerations from the LBNL memo as a starting point. This would allow Xcel to present on its current practices and potential advancements to its engineering practices. The workshop could then inform additional filing requirements based on the recommendations from LBNL **(Decision Option 44)**.

Project Prioritization

The LBNL memo points to project prioritization as "the most tractable topic for Commission review, a mature and well-documented area." It goes on to say "Project prioritization is the operational output of the planning process where all other standards converge. It also is where the Commission and ratepayers are most directly affected. The sequence and prioritization of projects determine the timing of rate impacts and the distribution of reliability benefits across the system."²⁰⁹

Staff believes discussions around project prioritization are the most immediate and relevant area for stakeholder input given the advent of Proactive Grid Upgrades and DSRUP coinciding with distribution-based load growth. When DSRUP is launched, likely in 2027, there are anticipated to be more upgrades to construct than Xcel can feasibly accommodate simultaneously. While there is a prioritization process for projects within DSRUP, there has not been a conversation about how those upgrades should be prioritized in regard to other distribution system upgrades that are not related to DER adoption. ELPC/CEF/VS have also recommended including equity criteria in Xcel's prioritization process, similar to what Michigan utilities have adopted. Staff believes this could also be discussed within the overall prioritization conversation **(Decision Option 45)**.

There are many reasonable and prudent ways for a utility to design and engineer its distribution system. To some extent, the Commission should be indifferent to Xcel's approach as long as

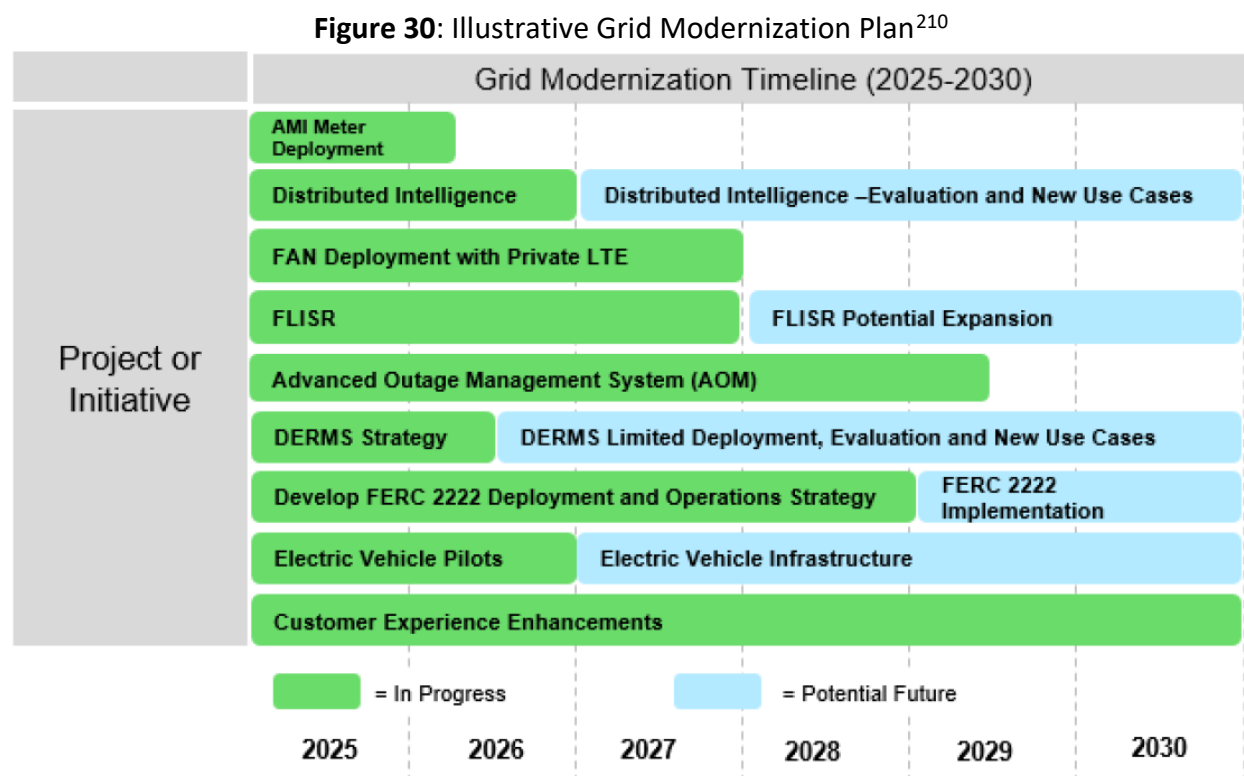
²⁰⁸ LBNL Memo, p. 17

²⁰⁹ LBNL Memo, pp. 15-17

overall goals are being met: safety, reliability, affordability, carbon reduction, and customer ability to interconnect generation and load. Put another way, it is Xcel's job to design its standards and the Commission's job, through the record developed by stakeholders, to determine if they are prudent and result in reasonable investments that deserve cost recovery.

G. Grid Modernization

As in prior IDPs, Xcel provided its grid modernization roadmap (Figure 30) which depicts the Company's planned investments.



Staff notes that the graphic included in the current IDP only goes through 2030, while prior similar graphics portrayed a 10-year time-horizon.

Table 8 gives additional information on Xcel's planned grid modernization investments in Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), Advanced Outage Management (AOM), and Distributed Intelligence (DI).²¹¹

²¹⁰ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 5 (PDF pp. 200), Figure 5-2.

²¹¹ Xcel 2025 Integrated Distribution Plan, Chapter 5, pp. 7-8 (PDF pp. 202-203).

Table 8. Grid Modernization Foundational Technologies and Initiatives

Program	Implementation Timeline
ADMS	ADMS provides situational awareness and automated capabilities to manage the grid.²¹² Xcel notes that it has completed implementation of the ADMS and submitted its final Annual Report in January 2024, in Docket Nos. E002/M-23-452 and E002/M-23-467. The Company is recovering its costs through the Transmission Cost Recovery (TCR) rider. The current version of ADMS will reach its end of life in mid-2026. The Company is planning for the next phase of distribution management through its Advanced Outage Management (AOM) project.
AMI	AMI consists of Xcel's advanced meters, communication networks, and software enabling two-way communication between the Company's data systems and customer meters.²¹³ Xcel completed the installation of 1.41 million AMI meters by the end of 2025 with a small number of legacy meter replacements anticipated in 2026.²¹⁴ Xcel expects \$14.4 million in capital costs for its AMI through 2027.²¹⁵ The Company is recovering the costs through the TCR rider.
FAN	Xcel's FAN is a two-way communication network providing wireless service to and from meters, field devices, and information systems.²¹⁶ It consists of two separate technologies: a lower-speed private mesh network and a high-speed network backhaul. Both interact with the Company's Wide Area Network (WAN). Xcel is nearing completing of its FAN and work may continue into 2026.²¹⁷ The Company is recovering the costs through the TCR rider.
FLISR	Uses ADMS, two-way communication, and automated field and substation equipment (reclosers, switches, relays) to detect system issues, isolate them, and restore power in the event of an outage.²¹⁸ 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 2027.²¹⁹ Xcel stated that FLISR technology is also useful for wildfire mitigation to more quickly de-energize distribution lines and trigger an outage.²²⁰

²¹² Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 9 (PDF p. 204).

²¹³ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 10 (PDF p. 205).

²¹⁴ Xcel 2025 Integrated Distribution Plan, Chapter 5, pp. 10-11 (PDF pp. 205-206).

²¹⁵ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 12 (PDF p. 207).

²¹⁶ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 12 (PDF p. 207).

²¹⁷ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 14 (PDF p. 209).

²¹⁸ Xcel Integrated Distribution Plan, Chapter 5, p. 16 (PDF p. 211).

²¹⁹ 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 received approval for recovery of additional FLISR costs in its recently concluded rate case, Docket No. E002/GR-24-320.

²²⁰ Xcel Integrated Distribution Plan, Chapter 5, p. 17 (PDF p. 212).

AOM	Xcel's Advanced Outage Management (AOM) project would consolidate multiple software platforms into a single distribution management platform.²²¹ This involves upgrading the current ADMS, performing a hardware refresh of data center sites, and implementing a new outage management system. The AOM would also support the push for more advanced outage management including fire mitigation deployment, the application of which is planned for 2026. AOM costs for 2025 and 2026 were approved in Xcel's 2024 rate case. Xcel envisions \$54.8 million in capital costs over the five-year budget period.
DI	Xcel's Distributed Intelligence (DI) refers to the ability of AMI meters to process data on-site via Edge Chip hardware and software programs known as Agents.²²² The Company explains details three main attributes of the DI:²²³ • High Impedance Detection: allows the meters to detect deteriorating or loose connections proactively which can be addressed before they cause outages. High Impedance Detection is deployed on approximately 62,000 meters in Minnesota. • EV Detection: can provide the Company with insights into where EVs are located and charging patterns of customers to support system planning, load balancing, and infrastructure upgrade efforts. 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: 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. The Company currently has Location Awareness deployed on approximately 146,000 meters in Minnesota. Xcel envisions \$0.3 million in capital costs for over the five-year budget period in Technology Services.

1. Fault Location Isolation and Service Restoration (FLISR)

Xcel requested a budget of \$31.8 million over two years in its rate case for FLISR capital and O&M expenditures, which was approved by the Commission in its June 18 oral decision in Docket 24-320.²²⁴ Xcel stated that it was not yet able to quantify the benefits across its system, but some limited evidence shows a reduction in customer minutes out (CMO).²²⁵ Xcel provided data to the Department, citing 30 FLISR activations, which are estimated to have saved 2,843,298 CMOs, valued at \$8,672,059 in monetized reliability benefits using Xcel's \$3.05 / CMO value.²²⁶

²²¹ Xcel 2025 Integrated Distribution Plan, Chapter 5, pp. 21-22 (PDF pp. 216-217).

²²² Xcel 2025 Integrated Distribution Plan, Chapter 5, pp. 23-24 (PDF pp. 218-219).

²²³ Xcel 2025 Integrated Distribution Plan, Chapter 5, p. 24 (PDF p. 220).

²²⁴ Xcel Integrated Distribution Plan, Chapter 5, p. 18 (PDF p. 213).

²²⁵ Xcel Integrated Distribution Plan, Chapter 5, pp. 19-20 (PDF pp. 214-215).

²²⁶ Department 2-27-26 Initial Comments, p. 97.

Xcel noted that, while it expects FLISR to improve overall reliability, some metrics (MAIFI and CAIDI) may worsen, as outages may change from sustained to momentary, and if easily fixable interruptions decline, average longer outages may increase.

The Department and Xcel went back and forth on the potential value of publishing more granular data to determine circuit-level performance, but ultimately the Department did not make recommendations at this time.²²⁷

2. Staff Analysis

As Staff explained in the Company's recently concluded rate case, it has been difficult to track Xcel's grid modernization plans across proceedings especially as it pertains to total spending and the interrelatedness of various technologies.

Information on ADMS implementation and future plans has been fractured across multiple filings and proceedings, including the initial certification request, annual ADMS reports in the TCR Docket, rate cases, and Xcel's IDP...[Staff] makes two recommendations for future rate cases to ensure the Commission is receiving complete information on the scope and scale of grid modernization investments. First, Staff recommends requiring the Company to provide the forecasted lifetime budget for multi-year grid modernization investments in future rate cases. Second, Staff recommends requiring a description of any future associated investments outside the scope of the current rate case that will be needed to fully implement the proposed grid modernization technology.²²⁸

While the decision option was not included in the rate case decision, Staff reiterates it here as both an IDP requirement, and as a future rate case requirement (**Decision Option 47**).

Require Xcel to include the forecasted lifetime budget for multi-year grid modernization investments in future rate cases and IDPs and a description of any future associated investments outside the scope of the current rate case or IDP that will be needed to fully implement the proposed grid modernization technology.

As part of the IDP Improvement Workgroup (Decision Option 5) Staff would work with stakeholders to rewrite this as an IDP filing requirement.

H. DER Management System (DERMS)

In this section the Commission will have the opportunity to order Xcel to continue filing information on its DERMS roadmap, use cases, and its stakeholder engagement with interested parties (**Decision Option 48**). ELPC/CEF/VS recommends a BTM VPP program proposal in a separate docket by July 1, 2027 (**Decision Option 49**). The Commission may also choose to pursue two different pilots regarding DERMS use cases. The Department recommends an Aggregator DERMS pilot for demand response capabilities (**Decision Option 50**) and CEE recommends an Aggregator DERMS pilot that utilizes dual load control (**Decision Option 51**).

²²⁷ Department Reply Comments, p. 63.

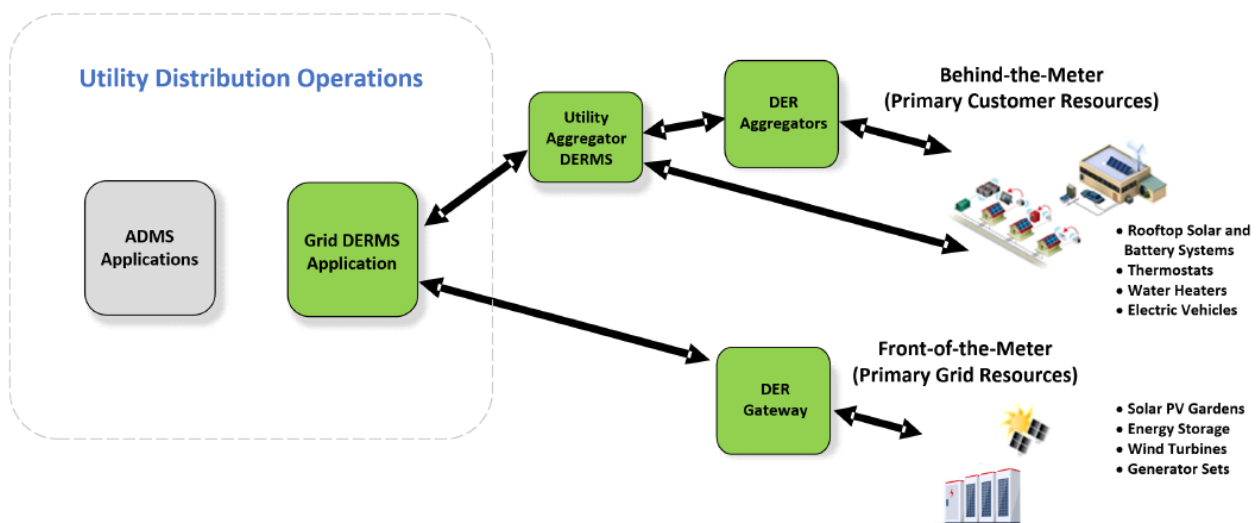
²²⁸ Staff Briefing Papers Volume 1: Financial Issues, Docket E002/GR-24-320

Xcel established in its IDP that DERMS is an “ecosystem of software platforms, business processes, and policy frameworks” rather than a single system.²²⁹ Xcel identified three components or types of DERMS, listed below:

- **Grid DERMS:** Primarily manages front-of-the-meter resources and serves as DER monitoring, control, and coordination application as an extension to the existing Advanced Distribution Management System (ADMS).
- **Aggregator DERMS:** Primarily manages 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) under FERC Order 2222. 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.²³⁰

Figure 31 depicts Xcel’s diagram of its enterprise DERMS architecture.

Figure 31: High-Level Enterprise DERMS Architecture – Illustrative Example²³¹



²²⁹ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 2 (PDF p. 416).

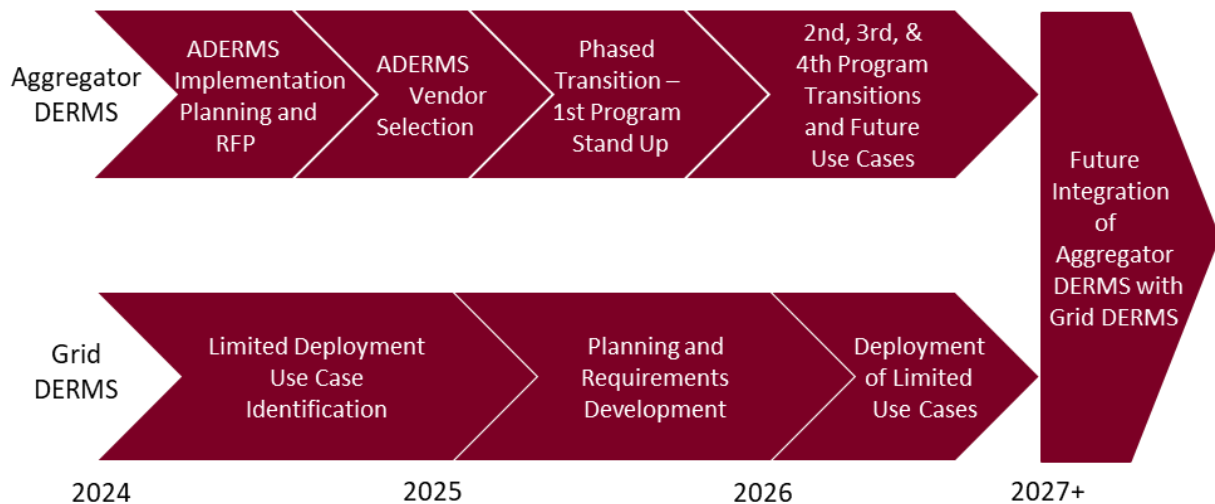
²³⁰ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 2 (PDF p. 416).

²³¹ Xcel 2025 Integrated Distribution Plan, Figure 11-1, Chapter 11, p. 3 (PDF p. 417).

1. DERMS Roadmap and Deployment

Xcel provided a timeline of its DERMS implementation process in Figure 32. The Company noted that its Aggregator DERMS and Grid DERMS will continue deployment through 2027 beyond, with the introduction of the Enterprise DERMS to follow.

Figure 32: DERMS Technology Implementation Timeline²³²



Xcel identified five phases for their DERMS roadmap. More information on the phases can be found in their filing.²³³

- Phase 1: Foundation and Planning (2024)
- Phase 2: Initial Implementation (2025)
- Phase 3: Phased Deployment and Integration (2026)
- Phase 4: Expansion and Optimization (2027+)
- Phase 5: Enterprise DERMS (Long-Term)

Xcel plans to make both its Grid and Aggregator DERMS programs voluntary to participate in for DER customers. Its use-case requirements will also depend on the resource size and type, type of program participation (demand response, interruptible load, capacity procurement), market participation (e.g. whole vs aggregator markets), and interconnection characteristics.²³⁴

Xcel identified and evaluated three different deployment pathways for their DERMS roadmap in their IDP filing:²³⁵

- Pathway 1: Phased Parallel Path Deployment
- Pathway 2: Consolidated Single Vendor Approach
- Pathway 3: Vendor Dependent

²³² Xcel 2025 Integrated Distribution Plan, Figure 11-2, Chapter 11, p. 4 (PDF p. 418).

²³³ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 4-6 (PDF p. 418-420).

²³⁴ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 16 (PDF p. 430).

²³⁵ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 9 (PDF p. 423).

Xcel explained that it has already started pursuing Pathway 1 and emphasized its ability to mitigate risk regarding the requirement and implementation to existing commitments and regulatory requirements as it is a more agile approach that starts smaller in scope. The Company noted there will be more risk during the integration phase of Grid and Aggregator DERMS.

The Department requested the Company expand on its claims that a single vendor would have longer timelines and higher costs compared to the other pathways. Xcel responded by stating that their Request for Information (RFI) process determined that “no single vendor could meet all requirements for both Aggregator and Grid DERMS due to the two types of DERMS relying on mature ADMS and DRMS systems which are two different types of products with not much overlap.”²³⁶ The Department agreed with Xcel’s assessment that a consolidated single vendor approach is not recommended and that approach would lead to longer implementation timelines and higher costs.²³⁷ CEE broadly agreed with Xcel’s deployment strategy and roadmap citing a Smart Electric Power Alliance (SEPA) report as well as the overlap in timing of MISO’s implementation of FERC’s Order 2222.²³⁸

While ELPC/CEF/VS broadly supported DERMS and maintained that the Commission will be able to rule on cost recovery in future rate cases, the group recommended continuation of the requirement for Xcel to describe its DERMS plans, use cases, and stakeholder engagement in its Integrated Distribution Plans. ELPC/CEF/VS explained this will ensure that the Company continues to make only necessary, cost-effective DERMS investments and realizes the expected benefits in its intended DERMS use cases (**Decision Option 48**).²³⁹ In reply comments, the Department supported this recommendation.²⁴⁰

2. DERMS Costs

Xcel stated that it has planned deployments for Aggregator DERMS and a limited Grid DERMS and so provided known costs to those plans. The Company added that while the categories of costs will be the same it does not have any known costs for the expected integration of the two types of DERMS in the Enterprise DERMS phase of its roadmap.

i. Aggregator DERMS

Xcel stated that it expects to recover costs related to Aggregator DERMS’ deployment through existing pathways like the ECO program but that specific pathways may vary depending on the nature of the program.²⁴¹ Xcel stated that cost categories include deployment, licensing, and ongoing operation and infrastructure costs.

²³⁶ Department 2-27-26 Initial Comments, Attachment B, p.55

²³⁷ Department 2-27-26 Initial Comments, pp. 94-95

²³⁸ CEE 2-26-26 Initial Comments, pp. 4-5.

²³⁹ ELPC/CEF/VS 2-26-26 Initial Comments, p. 40.

²⁴⁰ Department 4-23-26 Reply Comments, p. 65.

²⁴¹ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 21 (PDF p. 435).

The Department requested that Xcel provide an estimate for the deployment of Aggregator DERMS. The Company stated that it would range from \$4 to \$6 million over several years and which did not include the costs to integrate it with distribution management tools.²⁴²

ii. Grid DERMS

The Company wrote that the limited Grid DERMS deployment of approximately \$2.9 million requested as part of its Capacity*Connect proposal will be used for flexible interconnection, flexible energization, and Capacity*Connect implementation. Specific costs include software design and architecture, development of detailed processes, functional and technical requirements, licensing, system testing and validation, and integration with existing grid systems and platforms.²⁴³

The Department requested that Xcel provide an estimate for the full deployment of Grid DERMS to which the Company stated that doing so right now would not be possible as the costs involved vary significantly.²⁴⁴ The Department noted that while the costs indicated by the Company for the initial two DERMS deployments are modest but that “the potential quantifiable benefits and costs of DERMS remains mostly unknown to Xcel.”²⁴⁵

3. *DERMS Use Cases*

In response the 2023 Commission IDP Order that required Xcel to describe DERMS use cases in greater detail, the Company provided use cases for its Grid, Aggregator, and Integrated DERMS.²⁴⁶

i. Grid DERMS – Flexible Interconnection

Xcel stated that it is exploring Flexible Interconnection, Flexible Energization, and the Capacity*Connect through Grid DERMS. Xcel explained that Grid DERMS can enable flexible interconnection which would allow the DER operator to curtail DER output during periods of distribution grid constraint, keeping generation within operating limits while permitting the DER system to remain connected to the grid.²⁴⁷

ELPC/CEF/VS supported Xcel’s DERMS adoption and noted that it would be an iterative process.²⁴⁸ They claimed that Grid DERMS could facilitate flexible interconnection measures but also reiterate that DERMS should not be a reason to eschew static flexible interconnection. ELPC/CEF/VS emphasized that static and dynamic FI are critical for Xcel to adopt and should be

²⁴² Department 2-27-26 Initial Comments, Attachment B, IR 59 (PDF p. 228).

²⁴³ Xcel 2025 Integrated Distribution Plan, Chapter 11, pp. 21-22 (PDF p. 435-436).

²⁴⁴ Department 2-27-26 Initial Comments, Attachment B, IR 58 (PDF p. 227).

²⁴⁵ Department 2-27-26 Initial Comments, p. 96 (PDF p. 228).

²⁴⁶ Xcel 2025 Integrated Distribution Plan, Chapter 13, p. 14 (PDF p. 427).

²⁴⁷ Xcel 2025 Integrated Distribution Plan, Chapter 13, p. 14 (PDF p. 427).

²⁴⁸ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 37-38.

pursued in a phased approach instead of delaying the implementation to wait for DERMS investments. MNSEIA agreed with ELPC/CEF/VS and added that based on Xcel's comments, dynamic FI is still several years from operation and static FI would provide benefits in the interim.²⁴⁹

ii. Grid DERMS – Flexible Energization

Xcel explained that flexible energization refers to using Grid DERMS to flexibly manage load during periods of grid capacity constraints. Similar to FI, Grid DERMS can curtail load either as a firm limit or during peak demand periods. Xcel stated that it would work directly with developers during the interconnection process to develop schedules that reflect expected operating envelopes or limits based on forecasted grid conditions and identify relevant system constraints. Xcel believed FE can speed up the interconnection timeline and provide the Company with enhanced visibility and control to operate the grid within its capabilities.²⁵⁰

iii. Grid DERMS – Distributed Capacity Procurement

Xcel wrote that its Capacity*Connect program is a new way to provide utility-scale battery energy storage systems across the Company's distribution system.²⁵¹

The Department expressed interest in Xcel's DERMS given the potential to provide enhanced demand response at the feeder level to avoid distribution grid upgrades and pass cost savings onto ratepayers.²⁵² The Department noted that commenters in the Capacity*Connect proceeding²⁵³ raised concern that the closed-loop proprietary design of Xcel's DERMS lacks interoperability, preventing current or future third-party front-of-the-meter resources or aggregators from participating in distribution service markets.²⁵⁴

ELPC/CEF/VS pointed to Capacity*Connect as an example of the Company missing a critical opportunity to leverage DERs as cost effective distribution system resources. In that proceeding, Xcel is treating the battery assets primarily as bulk system assets with coincident distribution system benefits.²⁵⁵ ELPC/CEF/VS reiterated that Limited Grid DERMS could complement Capacity*Connect, such as by dispatching storage resources for distribution-level constraints in certain instances, in addition to addressing bulk system needs (such as a MISO signal).²⁵⁶

²⁴⁹ MNSEIA 2-26-26 Initial Comments, p. 11.

²⁵⁰ Xcel 2025 Integrated Distribution Plan, Chapter 13, p. 13 (PDF p. 427).

²⁵¹ Xcel 2025 Integrated Distribution Plan, Chapter 13, p. 13 (PDF p. 427).

²⁵² Department 2-27-26 Initial Comments, pp. 91-93.

²⁵³ E002/M-25-378

²⁵⁴ Docket No. E002/M-25-378, *In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program*, Xcel Energy, Petition, October 3, 2025.

²⁵⁵ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 10-11.

²⁵⁶ ELPC/CEF/VS 2-26-26 Initial Comments, p. 39.

iv. Aggregator DERMS – Scalable DER Management; Enhanced Grid Visibility and Control

Xcel outlined its plans to transition around 680 MW of existing load flexibility and interruptible load programs into an Aggregator DERMS platform.²⁵⁷ Xcel claimed that Aggregator DERMS can provide scalable DER management which include BTM assets.²⁵⁸

ELPC/CEF/VS requested Xcel expand on these use cases and wanted clarification on whether this use case will only apply to demand response sources. The group also suggested Xcel consider if these use cases can help support electric school bus or vehicle-to-grid power injection on the generation side and electric vehicle charging on the load side.²⁵⁹ The group added that they had recommended that the Commission order Xcel to develop and file a separate Distributed Power Plant (DPP) in the Capacity*Connect docket.

In reply comments, Xcel claimed that recommendations for changes to the Capacity*Connect program and the creation of Distributed/Virtual Power Plants are out of scope of the IDP and should be dealt with in the respective dockets.²⁶⁰

ELPC/CEF/VS claimed that a BTM DPP would better leverage existing investments, including AGIS and AMI and would lead to lower costs for ratepayers.²⁶¹ The group agreed with Xcel that the IDP proceeding would not be the most appropriate place to have that discussion. The group therefore recommended the Commission require Xcel to file a BTM DPP program proposal in a separate docket by July 1, 2027 (**Decision Option 49**).²⁶²

The Department is unclear how Xcel will incorporate the local grid benefits from DERMS into its DER hosting capacity planning assumptions and/or NWA analysis. The Department requested Xcel explain how it would realize such local benefits, beginning with its Aggregator DERMS before a wide-scale rollout of the program occurs. The Department emphasized that “it is important that Xcel begin a pilot in this IDP to provide direction in its next IDP for essential Enterprise DERMS solutions” and gave an example that the program could select one or more feeders to sign up customers for a new demand response program that curtails assets for system-wide and localized grid benefits (**Decision Option 50**).²⁶³ The Department recommended the demand response pilot at a minimum should:

- Test different incentive levels to determine the optimal incentive structure;
- Test at least two controllable load types; and
- Provide a cost-benefit analysis of localized distribution grid benefits compared to standard distribution grid upgrades

²⁵⁷ Xcel 2025 Integrated Distribution Plan, Chapter 13, p. 14 (PDF p. 428).

²⁵⁸ Xcel 2025 Integrated Distribution Plan, Chapter 14, p. 13 (PDF p. 428).

²⁵⁹ ELPC/CEF/VS 2-26-26 Initial Comments, p. 39.

²⁶⁰ Xcel 3-19-26 Reply Comments, Attachment A, p. 34 (PDF p. 42).

²⁶¹ ELPC/CEF/VS 4-23-26 Reply Comments, p. 8.

²⁶² ELPC/CEF/VS 4-23-26 Reply Comments, p. 8.

²⁶³ Department 2-27-26 Initial Comments, p. 94.

In reply comments Xcel did not support the Department's recommendation. Xcel stressed that the IDP is not the appropriate venue for this recommendation, as the IDP is not intended for discussion of the design or implementation of customer incentive programs or DER pilot structure. Xcel remarks that the consideration of an Aggregator DERMS pilot program should take place in the Company's ECO Triennial Plan.²⁶⁴

In response the Department noted that Xcel did not oppose the pilot based on its merits but on the venue (the IDP). The Department stated that while the IDP may not be the best venue to enact a pilot, it is an appropriate place to ask for one and maintained its recommendation.²⁶⁵

v. Aggregator DERMS – Air Source Heat Pumps (ASHP) – CEE

CEE cited the integration of ASHPs into utility grid operations as a potential use case for Aggregator DERMS.²⁶⁶ CEE stated that growing adoption of ASHPs will increase electric loads during winter peaks and that in instances where ASHPs are combined with a backup heat source like natural gas, known as a dual fuel source application, the backup source can lower electric loads during winter peaks. Dynamic control over these heat sources, which would require an Aggregator DERMS, and allowing utilities to control ASHPs by switching to the gas furnace based on certain system characteristics and market signals could provide additional value through grid management and ratepayer benefit opportunities during winter heating seasons."²⁶⁷

CEE recommended the Commission order Xcel to develop and propose a pilot to explore dual fuel load control applications to manage system impacts of electrified residential space heating in a proceeding determined by the Commission (**Decision Option 51**).

CEE supported a start time at the beginning of the 2027-2028 heating season so that it could align with Xcel's Aggregator DERMS expansion timeline and give time for the pilot development, proposal, and regulatory review. CEE suggested the pilot consider the following:²⁶⁸

- Test kW reduction potential and other distribution system metrics from load control activities at specific times and locations on the electric system
- Evaluate customer experience with the program
- Develop and test system communication frameworks and processes, including integration into Xcel's Aggregator DERMS platform
- Explore how a larger aggregated dual fuel load control program could align with bulk system value through MISO resource offerings

²⁶⁴ Xcel, 3-19-26 Reply Comments, Attachment A, p. 36 (PDF p. 44).

²⁶⁵ Department 4-23-26 Reply Comments, p. 62 (PDF p. 68).

²⁶⁶ CEE 2-26-26 Initial Comments, p. 5.

²⁶⁷ CEE 2-26-26 Initial Comments, pp. 5-6.

²⁶⁸ CEE 2-26-26 Initial Comments, pp. 12-13.

In reply comments Xcel opposed CEE's request for a pilot on dual fuel load control pilot, stating that it is out of scope for the IDP and better addressed in the Company's ECO Triennial Plan. CEE disagreed with the Company and claimed that a new docket would avoid concerns about managing programmatic details in system-wide distribution planning dockets. However, CEE was open to further discussion for the best timing and location for pilot development, including the pilot commencing during the 2028-2029 heating season.²⁶⁹

vi. Enterprise DERMS Use Case

Xcel elaborated that it would integrate Grid DERMS and Aggregator DERMS along with IT and OT system within an overarching Enterprise DERMS system that would "enable 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."²⁷⁰ Xcel added that the DER involved would include customer-owned assets, as well as utility-affiliated and third party aggregators.

The Company listed the following use cases to illustrate the potential types of advanced functionality being considered:²⁷¹

- Provide real-time and predictive visibility for grid operators into the aggregate behavior of BTM DER.
- Enable distribution level services through coordinated control of aggregated energy storage, EV charging, and demand response to manage distribution system constraints.
- Support for FERC Order 2222 through enhanced market integration and operational coordination.

4. *Staff Analysis*

ELPC/CEF/VS and the Department recommend that the Commission order Xcel to continue to describe its DERMS plans, use cases, and stakeholder engagement in future IDPs (**Decision Option 48**). Staff supports this recommendation. DERMS deployment is still in its beginning stages and continued oversight will be informative.

ELPC/CEF/VS recommended the Commission order Xcel to file a BTM VPP program proposal in a separate docket by July 1, 2027. Staff supports Xcel starting a customer-sourced VPP program in the near term so it can maximize distribution connected resources ahead of Order 2222 coming into force (**Decision Option 49**).

The Department recommended the Commission order Xcel to begin an Aggregator DERMS demand response pilot that should (**Decision Option 50**):

- Test different incentive levels to determine the optimal incentive structure;
- Test at least two controllable load types; and

²⁶⁹ CEE 4-23-26 Reply Comments, p. 4.

²⁷⁰ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 13 (PDF p. 428).

²⁷¹ Xcel 2025 Integrated Distribution Plan, Chapter 11, p. 15 (PDF p. 430).

- Provide a cost-benefit analysis of localized distribution grid benefits compared to standard distribution grid upgrades

Staff agrees with the Department that an Aggregator DERMS pilot could offer some insight and information, however, it is unclear how long this pilot would take to create and implement relative to Xcel's planned deployment. Staff also agrees with Xcel that the ECO Triennial Plan is the most appropriate location to submit a pilot proposal. Additionally, Staff is unsure of the size, scale, and timeline of said timeline. However, the Commission may choose this decision option if it prefers an expedited pilot implementation. Staff recommends it proceed via a new docket if the Commission were to pursue that route.

CEE recommended that the Commission order Xcel to develop and file a dual fuel load control pilot for Commission consideration in a proceeding determined by the Commission (**Decision Option 51**). Staff believes that if the Commission is interested in piloting a specific use case for Aggregator DERMS, a dual fuel load control pilot may be viable, timely, and informative. CEE points out that Xcel already offers rebates for ASHPs through its ECO program. Xcel forecasted increased adoption starting in 2030 and noted that they will be one of the leading causes for peak load to switch from summer to winter.

Xcel believes this pilot would be better introduced through its ECO Triennial plan but CEE makes the argument that the pilot would be directly tied to the management of Xcel's distribution system, would integrate well implementation of DERMS, and due to those factors, should be under the Commission's purview rather than the Department's as would be the case under an ECO pilot. Staff agrees with these sentiments – that ASHPs, when controlled via a DERMS application, should be overseen by the Commission.

Staff believes that studying this type of application of DERMS with this specific technology, one that the Company already offers rebates for and forecasts in their load forecasting, the Company and the Commission will gain greater insight into how scaling this type of pilot may work and how the beneficial impacts it will have on the distribution grid. If the Commission supports this pilot, Staff is indifferent on whether it begins in the 2027-2028 or 2028-2029 heating season.

I. DER Integration

1. Flexible Interconnection

Flexible interconnection (FI) is an emerging DER control strategy that can be used to accommodate more DER integration without the normal system upgrades that may usually be necessary. This can be done by having some DERs experience temporary curtailment during times of grid constraint. The tradeoff is that FI allows for lower cost DER interconnection and raising the total average DER generation output but at the expense of capping the maximum generation output that could occur.

There are two types of FI discussed in this IDP – static and dynamic. Static FI allows for a pre-set threshold that DERs cannot export beyond and utilizes local and autonomous control systems via smart inverters rather than an advanced power and control system. Dynamic FI uses Grid DERMS which has a much greater ability to monitor and adapt to near-term variables and grid conditions such that curtailment will be much more precise.

i. Xcel Timeline and Stages

In its September 16, 2024 Order in Xcel’s 2025 IDP the Commission required the Company to: [D]emonstrate its 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 implementation of flexible interconnection, DERMS, and dynamic hosting capacity.²⁷²

In its 2025 IDP Xcel noted that while static flexible interconnection (FI) is technically feasible currently, it has many limitations that make it less attractive than dynamic FI.²⁷³

The Company emphasized that a static FI scheme meant that Xcel would have to conduct detailed system studies to define flexible operating limits, estimate potential curtailment, and develop a fixed annual operating schedule which must be conservatively designed to account for all possible conditions. Xcel claimed this may lead to greater curtailment for DER owners, including reduced revenues due to curtailment, which would be more severe under static FI than dynamic FI.

At the time of the 2023 IDP, Xcel did not have a clear implementation timeline for its DERMS platform. However, now that it expects limited DERMS deployment in 2026, Xcel plans to prioritize dynamic FI over static FI, focusing specifically on DER sites 1 MW or larger.²⁷⁴ For Stage 1, Xcel stated that it would begin limited DERMS deployment in Q3 2026, selecting five to ten feeders based on their use case implementation, including dynamic FI.²⁷⁵ The Company added that dynamic FI would be similar to static FI in that it would require tailored study requirements and communication equipment installed onsite.

The Company stated that Stage 2 would focus on the operation and validation of FI and potentially scaling it beyond the initial five-ten feeders while also enhancing its Hosting Capacity tools to provide greater information to developers.²⁷⁶

²⁷² Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, September 16, 2024, Docket E002/M-23-452, Ordering Paragraph 19.

²⁷³ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 3 (PDF p. 286).

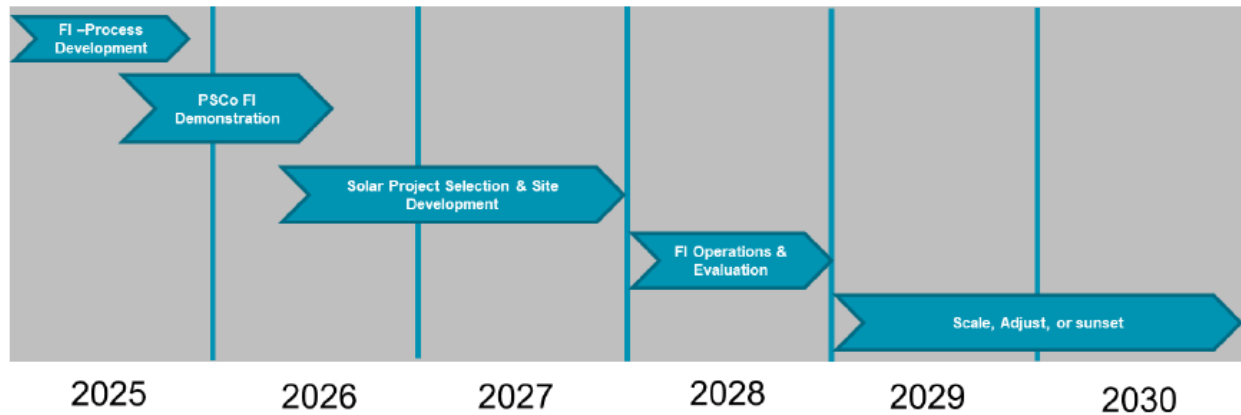
²⁷⁴ Xcel 2025 Integrated Distribution Plan, Chapter 7, pp. 3-4 (PDF p. 286-7).

²⁷⁵ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 4 (PDF p. 287).

²⁷⁶ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 5 (PDF p. 288).

Xcel provided its timeline for FI implementation in Figure 33 which has “FI Operations and Evaluation” over the 2028 timeframe and “Scale, Adjust, or Sunset” over 2029 and 2030.²⁷⁷

Figure 33: Xcel’s Flexible Interconnection Timeline



The Company noted that it would make use of an analysis of FI during the interconnection review process to help better understand curtailment conditions.²⁷⁸

ii. Static Flexible Interconnection and Order Point 19

The Department,²⁷⁹ ELPC/CEF/VS,²⁸⁰ JSP,²⁸¹ and Fresh Energy²⁸² all agreed that Xcel had not met Order Point 19 from the 2024 Commission Order²⁸³ and their plans of skipping over static FI in favor of dynamic FI would also not meet that order requirement. Order Point 19 states the following:

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:
- Implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and
 - Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.

ELPC/CEF/VS asserted that Xcel had not addressed the Commission’s Order points related to flexible interconnection by having improperly dismissed static FI as a solution and having dismissed the Commission’s direction to implement a staged approach towards flexible interconnection.²⁸⁴ The group stated that Xcel has made limited progress towards dynamic

²⁷⁷ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 5 (PDF p. 288).

²⁷⁸ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 6 (PDF p. 289).

²⁷⁹ Department 4-23-26 Reply Comments, p. 66

²⁸⁰ ELPC, CEF, VS 4-23-26 Reply Comments, p. 2

²⁸¹ JSP 4-23-26 Reply Comments, p. 5

²⁸² Fresh Energy 4-23-26 Reply Comments, p. 8

²⁸³ PUC, 8-16-24 Commission Order in Docket 23-452

²⁸⁴ ELPC/CEF/VS 2-26-26 Initial Comments, p. 17.

flexible interconnection arrangements enabled by DERMS and has not explored nearer-term approaches like static FI that do not require DERMS.²⁸⁵ ELPC/CEF/VS noted that the DGWG has only just begun to discuss FI with its education session on February 18, 2026.

ELPC/CEF/VS highlighted that Xcel's proposal for dynamic FI implementation is inadequate for the following reasons:²⁸⁶

- Detailed system impact studies are not unique to static FI, as currently DER operators already need to pass certain levels of studies and inspections before interconnection.
- Static FI can offer more predictability to DER operators compared to dynamic FI and thus be preferable to the latter.
- Static FI can complement dynamic FI, such as by serving as a fallback if DERs lose the communications link for short periods of time under dynamic FI, especially during an initial rollout of DERMS
- The proposal lacks key details about specific processes and practices it is developing for DERMS rollout (which is key to Xcel's dynamic FI)
- The proposal does not explain how the first pilot sites would be selected nor their exact locations
- The timeline does not indicate a timeframe for system-wide rollout of dynamic FI

ELPC/CEF/VS also strongly recommended that the Commission require Xcel to review materials from Ameren Illinois' FI report²⁸⁷ and The CHARGED Initiative²⁸⁸ and have Xcel incorporate these considerations into its program design and address these materials in its 2026 report and 2027 IDP.

JSP reasoned that static FI is a near-term solution for which the benefits can be reaped immediately at little cost, unlike dynamic FI, so Xcel has an imperative to still pursue static FI. Specifically "site-wide import and export controls are already included in Xcel's Technical Interconnection and Interoperability Requirements (TIIR). New software platforms, real-time grid communication infrastructure, or DERMS integration is not required for static FI, unlike for dynamic FI."²⁸⁹

JSP had similar sentiments to ELPC/CEF/VS in that static FI would build "institutional and technical experience" which the Commission recognized as important before a full DERMS

²⁸⁵ ELPC/CEF/VS 2-26-26 Initial Comments, p. 5.

²⁸⁶ ELPC/CEF/VS 2-26-26 Initial Comments, p. 18-19.

²⁸⁷ Report that had Ameren Illinois collaborate with the Charged Initiative to host a series of facilitated stakeholder engagement sessions for stakeholders representing both load and DER connectors. As a result, the utility plans to pursue phase 1 of its FI Plan which includes volt/watt settings, staggered interconnections, and limited import/export connections. <https://www.ameren.com/-/media/files/account/service-options/renewables/illinois/resources/flexible-interconnection-orchestration-report-phase-1.ashx>

²⁸⁸ A national group that works on Flexible Interconnection and grid modernization. <https://chargedinitiative.org/#about-link>

²⁸⁹ JSP 2-26-26 Initial Comments, pp. 9.

rollout in its 2024 order.²⁹⁰ JSP added that Xcel's argument that static FI would lead to lower revenues for developers compared dynamic FI is faulty as flexible interconnection is voluntary and customer-driven and that developers would be able to make business decisions for themselves.²⁹¹

In reply comments Xcel reiterated its dynamic-first approach to flexible interconnection due to the greater benefits it would provide over static FI.²⁹² Xcel indicated that they anticipate that its limited DERMS deployment and technical ability to implement FI will be ready by the time the DGWG's FI subgroup is finished developing the technical requirements prior to MNDIP or tariff updates before the Commission. Xcel notes that implementing static FI would require procedural and tariff changes to the MNDIP, which must occur through the DGWG and Commission processes.

Xcel also did not support the recommendation by ELPC/CEF/VS for Xcel to adopt Ameren/CHARGED models of flexible interconnection design (**Decision Option 52.e**). The Company maintains that it does not support prescriptive mandates to follow a particular model from other jurisdictions.

In reply, both ELPC/CEF/VS and JSP claimed that Xcel did not address their points on static FI. In particular, ELPC/CEF/VS pointed to the DER developers that may prefer static FI due to certainty of more rigid power import and export schedules and the reliability benefit that having static FI in addition to dynamic FI could keep some system online in the case of communication outages.²⁹³

Both parties reiterated that static FI offers a near-term option for those that would agree to a flexible interconnection agreement over waiting a minimum of three years for a broader rollout of dynamic FI and that it was an option that was feasible with the equipment already available.^{294;295} ELPC/CEF/VS added that this parallel pursuit of static and dynamic FI could insulate the progress toward FI in the case that Grid DERMS has any delays that may occur that could impact dynamic FI. Both parties also emphasized that Xcel's plan for future development beyond its limited Grid DERMS rollout was very unclear and did not provide assurance that FI in any form would be broadly available in the near future.

In collaboration, VS, ELPC/CEF/VS, the Department, and Fresh Energy recommend the Commission take up the following decision options (**Decision Options 52**):

Enforce 2024 IDP Order Point 19 and require Xcel to:

²⁹⁰ JSP 2-26-26 Initial Comments, pp. 10-11.

²⁹¹ JSP 2-26-26 Initial Comments, pp. 11.

²⁹² Xcel 3-19-26 Reply Comments, Attachment A, pp. 22-24 (PDF pp. 30-32).

²⁹³ ELPC, CEF, VS 4-23-26 Reply Comments, p. 3

²⁹⁴ ELPC, CEF, VS 4-23-26 Reply Comments, p. 2

²⁹⁵ JSP 4-23-26 Reply Comments, p. 5

- A. Revise its Flexible Interconnection proposal to develop and implement Static FI in the near term, prior to or in parallel with implementing full, Dynamic FI.
- B. Require Xcel to file, by December 31, 2026, a report on their FI efforts and plans in this docket, and include a specific update on their progress towards implementing static FI including elements such as technical standards, customer-facing documentation, and enablement timelines;
- C. Require Xcel to include updated information on Flexible Interconnection in its 2027 IDP, including the number of new load and DER connections utilizing static FI, the capacity made available as a result, and progress towards dynamic FI rollout;
- D. Require Xcel to incorporate and otherwise address discussions and learnings from the DGWG process in its 2026 and 2027 filing; and,
- E. Require Xcel to review materials from Ameren and CHARGED, who have worked extensively on Flexible Interconnection and present key considerations. We recommend that Xcel incorporate these considerations into its program design and address these materials in its 2026 report and 2027 IDP.

iii. Staff Analysis

Staff believes that Xcel may not comply Order Point 19 of the Commission's September 16, 2024 Order if the Company plans to omit its implementation of static FI as a standard interconnection offering in its plan to pursue only dynamic FI through Grid DERMS.

While it is understood that limited deployment of Grid DERMS and dynamic FI may be occurring sooner than anticipated in Xcel's 2023 IDP, Staff believes there are still benefits to continuing to pursue and implement static FI in the meantime. Static FI enables DERs to defer costly upgrades to the distribution system and allows for a greater utilization of the capacity that is safely available. Static FI can even be an interim solution while larger upgrades are paid for and built which can at times take several years to materialize. Additionally, while a limited deployment of dynamic FI may happen in the next year or two, it is not clear to Staff from the 2025 IDP that this will necessarily lead to a broader rollout to more feeders. As the other parties indicated, beyond 2027, information on Xcel's future plans for dynamic FI is scarce and does not inspire confidence or certainty in dynamic FI's future.

In contrast, static FI does not rely upon the advancement of Grid DERMS and Xcel already has the equipment necessary for implementation. In order to get to be a more standardized interconnection option, static FI will need changes to the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) and Technical Interconnection and Interoperability Requirements (TIIR) and subsequent tariff filings. The DGWG held an educational session in February 2026 and in June 2026 kicked off the formal subgroup process to update MNDIP to allow FI. The scope of the work will be more limited to the bare requirements for FI which may lead to an easier implementation of static FI. The finer policy and programmatic details of FI and in particular dynamic FI will be determined in a proceeding outside of the DGWG.

Staff also remains in agreement with the referenced Order from Xcel's 2023 IDP that a staged approach with Xcel getting experience with static FI before full implementation of dynamic FI

may provide great insight. Staff is also intrigued by the potential reliability benefit that ELPC/CEF/VS brought up for the scenario where there is a communication outage that could impact dynamic FI systems but not static FI systems which can remain operational.

For all of the reasons above, Staff supports the joint recommendation from ELPC/CEF/VS, JSP, Fresh Energy, and the Department (**Decision Option 52**).

2. *Planned Net Loading and Risk Analysis*

Xcel began developing its Planned Net Loading (PNL) methodology after its 2021 IDP to consider the DER impact to peak loads on feeders and substation transformers.²⁹⁶ PNL recognizes that a portion of DER output can be depended upon to lower or shave peak demand which means that, in planning, equipment may not need to be upgraded to be able to handle the full native load on the system.²⁹⁷ By recognizing dependable DER peak shaving ability, Xcel theorized that the distribution system can be smaller in size without losing reliability or over-relying on DER in its planning.

Current PNL Methodology

Xcel created a formula to calculate PNL using Planned Net Loading, Native Loading, Net Loading, and Dependability Factor. These terms are defined below:²⁹⁸

- **Planned Net Loading:** The amount of load in Megavolt Amperes (MVA) that must be planned for in Xcel's risk analysis and system planning process, after accounting for the impact of DER generation. Xcel's PNL methodology considers only CSG and rooftop PV generation.
- **Native Loading:** The actual, gross demand on the system or piece of equipment when all generation (DER) impacts are excluded. Xcel's load forecast uses native loading as calculated by LoadSEER.
- **Net Loading:** the actual demand after accounting for generation (DER) impacts. Net load on a specific element of distribution equipment is native load minus DER generation at that location, for that time period. Net loading is measured by the supervisory control and data acquisition (SCADA) system.
- **Dependability Factor (DF):** a ratio, output of a formula, or calculation that approximates the percentage of DER generation that can be relied upon to serve load relative to DER nameplate capacity.

²⁹⁶ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 84 (PDF p. 119).

²⁹⁷ Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 74 (PDF p. 129).

²⁹⁸ Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 76 (PDF p. 131)

Using these terms, Xcel created the following formula:

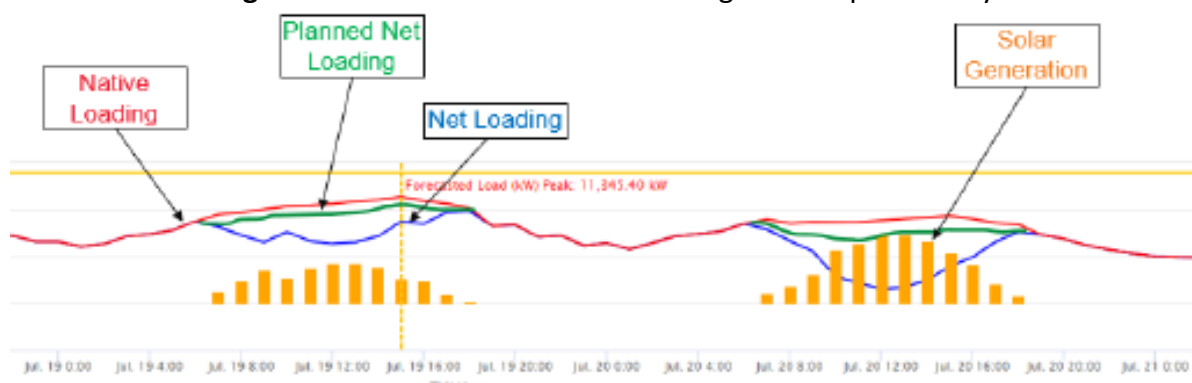
$$\text{Planned Net Loading} = \text{Native} - [(\text{Native} - \text{Net}) \times \text{DF}]$$

Where:

- DF = Dependability Factor of PV solar generation
- Net = The impact of the DER on Load
- Native = The full native load on the system
- DF = Dependability Factor

Xcel included an example diagram of a peak load curve considering DER dependability in Figure 34.

Figure 34: Peak Load Curve Considering Solar Dependability



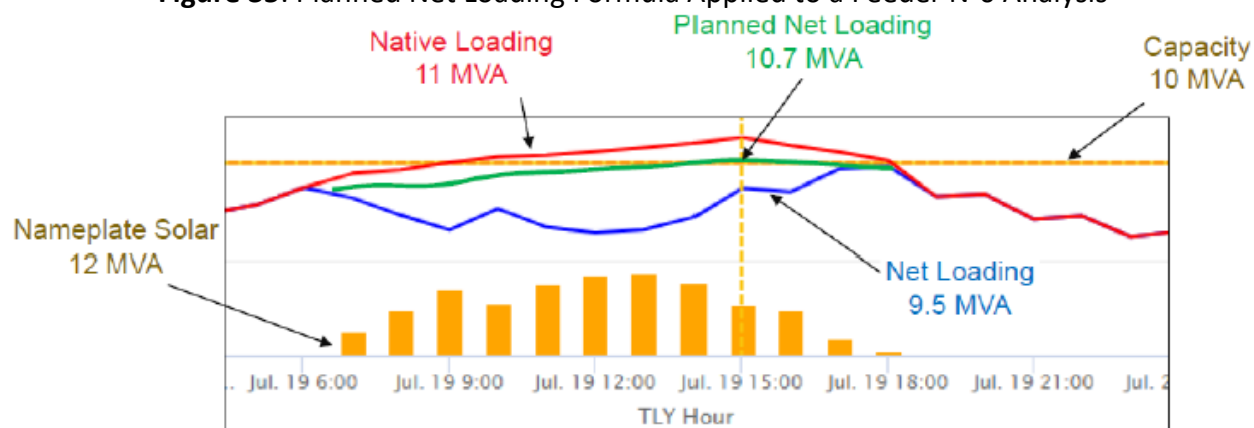
Net loading represents 100% of DER generation impact and native loading represents 0% of DER generation impact, while PNL reflects a certain percentage of dependable DER in between the aforementioned two loading types.²⁹⁹ In its 2023 IDP, as well as its 2025 IDP, Xcel derived a DF of 15% by averaging the three lowest PV output months (November, December, and January) of the CSGs on its system from 2016-2021 based on 08:00-18:00 solar tracking.³⁰⁰

Using a 15% DF, 11MVA for Native Loading, 9.5MVA for Net Loading, Xcel provided the following N-0 example³⁰¹ in Figure 35.

²⁹⁹ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 86 (PDF p. 121).

³⁰⁰ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 87 (PDF p. 122).

³⁰¹ In this case the N-0 example is a feeder that has 10 MVA capacity but has a native load of 11 MVA which means overloaded past 100% of the feeder's capacity.

Figure 35: Planned Net Loading Formula Applied to a Feeder N-0 Analysis

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

In this example the feeder in question has a capacity of 10 MVA. If load breaches this limit, Xcel quantifies it as an N-0 risk as it is overloaded. In the example Figure 35 above, native loading does breach 100% capacity at 11 MVA. Xcel's formula used Native Load, Net Load and the DF to determine that the 12 MVA of nameplate solar can reliably reduce system load by 0.3 MVA. Practically, this means that the feeder is still considered overloaded (since it must be less than 10 MVA) but the risk factor for the feeder is lower. This means that if Xcel must prioritize feeders to upgrade, this feeder upgrade could be somewhat deferred.³⁰²

Prior Commission Order

In its 2023 IDP Xcel first planned to use 15% as the dependability factor in its N-0 risk analysis. However, the Company appeared to change its mind in reply comments, requesting the Commission not order implementation of a 15% DF in the next planning cycle (2025).³⁰³ The Commission found that Xcel's PNL methodology warranted refinement and development and ordered the Company to work with stakeholders to further refine the methodology. Potential refinements discussed in the 2023 proceeding included alternative approaches to applying the dependability factor, such as applying it to hourly PV generation or to PV nameplate capacity, and evaluating the potential for seasonal dependability factors.³⁰⁴ Xcel was also ordered to include a report describing the results of this evaluation and changes to its proposed PNL methodology in its 2025 IDP. Additionally, while the Company was to work with stakeholders on refining the PNL, the Commission ordered Xcel to use a DF of 15% for its N-0 risk analysis in the interim to get more experience in applying a PNL.

³⁰² Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 87 (PDF p. 122).

³⁰³ Docket E002/M-23-452; Xcel Reply Comments, March 22, 2024

³⁰⁴ Docket E002/M-23-452, [September 16, 2024](#) Order, P. 16.

2025 IDP N-0 Analysis Results using PNL

Xcel used PNL, assuming a 15% DF_{PV}, for its risk and mitigation analysis in this IDP and found that it impacted the effective peak loading on 24 nodes out of 1,020 with some amount of DER. If a node is over 100% loading under N-0 conditions, the equipment is likely overloaded during peak demand and Xcel will evaluate the equipment for a capacity mitigation. Of the 24 nodes where PNL impacted the effective peak loading percentage, in four cases PNL brought the node below 100% loading.³⁰⁵

Table 9: 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

Xcel noted that the nine nodes that reflected a more significant change were still associated with little to no change in their risk score due to the fact most of the projects had other significant capacity risks. Xcel concluded 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.”³⁰⁶

Future PNL Methodology

Xcel stated that it had held a series of workshops with stakeholders, as directed by the Commission, in order to refine the PNL methodology. After several workshops, Xcel presented a proposal to adopt seasonal dependability factors (one for winter, one for summer) in its 2027 IDP. The Company also “committed to exploring additional refinements, such as using multiple solar profiles in LoadSEER to reflect geographic differences and investigating solar shapes by type.”³⁰⁷

The Department cautioned that the 15% figure is derived from a conservative analysis of 5 years of Minnesota community solar garden (CSG) data (2016-2021) and requested that Xcel provide a justification for continuing to use 15%. Additionally, due to PNL not deferring any projects, the Department requested that Xcel provide “a specific threshold in a risk score required to trigger a project deferral to ensure the PNL methodology is a functional planning tool.”³⁰⁸

The Department emphasized that seasonal values, such as one for the summer and one for the winter, would more accurately reflect the change in variation noting that tracking solar output reaches approximately 40.93% in July compared to only 11.78% in December, which suggests

³⁰⁵ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 88 (PDF p. 123).

³⁰⁶ Xcel 2025 Integrated Distribution Plan, Chapter 1, p. 89 (PDF p. 124).

³⁰⁷ Xcel 2025 Integrated Distribution Plan, Chapter 1, pp. 88-90 (PDF p. 124-125).

³⁰⁸ Department Initial Comments 2-26-26, p. 99, (PDF p. 107)

that the current year-round 15% factor is extremely conservative for summer peak planning. The Department recommended that Xcel evaluate the feasibility of accelerating the implementation of seasonal DF values before the 2027 IDP, given that the foundational data for these factors is already present in the current filing. The Department later withdrew this request in reply comments.

ELPC/CEF/VS indicated several disagreements with the IDP's PNL and risk analysis methodologies and claimed that Xcel did not adequately evaluate alternative PNL options.³⁰⁹

ELPC/CEF/VS submitted that they provided several alternative PNL methodologies in the 2023 Xcel IDP record and subsequent workshops including methods that are used by other utilities. ELPC/CEF/VS stated that despite this, Xcel barely discussed these alternatives in their 2025 IDP and did not model any alternatives in their analysis, including seasonal DF values, the one alternative method that they are considering despite this data being readily available.³¹⁰ ELPC/CEF/VS requested that for failing to substantively describe the results of its evaluation of alternative PNL methodologies and only providing minimal details to its proposed PNL methodologies, the Commission should order Xcel to file an interim update by December 31, 2026 that (**Decision Option 53**):³¹¹

1. Demonstrates that it has given due consideration to the alternative PNL methodologies presented by stakeholders and substantively evaluates those methodologies,
2. Provides specific details about seasonal dependability factors, including the percentages Xcel plans to use and which months would apply to each season, and
3. Analyzes the impacts of those seasonal dependability factors.

Xcel did not support the recommendations made by ELPC/CEF/VS about the Company's PNL methodology and the dependability factor. Xcel insisted that its current approach to PNL is consistent with the Commission's direction and ordering point.³¹² Xcel noted that while it has developed a seasonal approach to the dependability factor for its 2027 IDP and is supportive of continued refinement of PNL, the Company does not support interim filing or accelerated implementation outside of the planning cycle, which it argues may create redundant and inefficient reporting obligations.

ELPC/CEF/VS reiterated its stance that Xcel's PNL section of the IDP is lacking in details and that the Company failed to explain it is not feasible to immediately present seasonal DF values as it already has this data.³¹³ ELPC/CEF/VS also added that Xcel's reply failed "to substantively describe the results of its evaluation of alternative PNL methodologies" as was ordered by the Commission.³¹⁴

³⁰⁹ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 27-28.

³¹⁰ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 29.

³¹¹ ELPC/CEF/VS 2-26-26 Initial Comments, pp. 30.

³¹² Xcel 3-19-26 Reply Comments, pp. 9-10 (PDF pp. 17).

³¹³ ELPC/CEF/VS 4-23-26 Reply Comments, p. 14

³¹⁴ ELPC/CEF/VS 4-23-26 Reply Comments, p. 14

The Department noted that Xcel did not provide the information it requested and joined ELPC/CEF/VS recommendation for **Decision Option 53**.³¹⁵

Staff Analysis

Per the 2024 Commission Order, Xcel was required to use a 15% DF and apply PNL in its N-0 risk analysis.³¹⁶ Xcel was also required to work with stakeholders to refine and develop its PNL methodology and include a report describing the results of the evaluation and changes to its proposed PNL methodology in its 2025 IDP.

Xcel used a 15% DF for its N-0 risk analysis and held three stakeholder meetings with parties. However, it appears Xcel did not submit a report that included an evaluation of any of the proposed alternatives to Xcel's PNL methodology. Instead, the Company provided the results only for the modeling of the already-in-use 15% DF which came to the same conclusion as in the 2023 IDP: nine out of 1,005 nodes with DER impacted the percent loading but resulted in no change to risk scores or deferred capacity projects. These modest to negligible results were discussed during the 2023 IDP proceeding and appear to be attributable to the Company's conservative methodology and DF value.

The Commission ordered Xcel to use a 15% DF for its PNL N-0 risk analysis not because it deemed it to be the correct value, but because the Company's stance at the time was to not use PNL at all. The Commission understood a 15% DF to be a conservative value, low risk, and likely to not provide much benefit for deferring projects but potentially providing useful experience for the Company in the interim while it refined its methodology with stakeholder input.

Xcel worked with stakeholders, but failed to model or provide analysis on the alternative methodologies stakeholders proposed, including the one that they are considering for the 2027 IDP, seasonal DF values. As the Department and ELPC/CEF/VS indicated, Xcel did not provide an evaluation despite being ordered to by the Commission and having the data and ability to do so.

To Staff's understanding, the PNL information in this IDP does not appear materially different in from the 2023 IDP. Ideally, the Commission and parties would have had modeling results of different PNL methodologies to analyze, discuss, and make informed decisions on, but that is not possible given Xcel's input on the subject.

Staff supports the general recommendations of ELPC/CEF/VS with modifications. Staff offers a new subpart d to **Decision Option 53**:

- d. An analysis of the pros, cons, limitations, and opportunities for each of the different methodologies and which they may incorporate in the future and why.

³¹⁵ Department 4-23-26 Reply Comments, p. 70 (PDF p. 76)

³¹⁶ Docket E002/M-23-452, [September 16, 2024](#) Order, P. 16.

Staff believes the information requested in this decision option, or close to it, should have been provided by Xcel in its 2025 IDP. Since it was not, Staff does not give credence to Xcel's claim that this will be a duplicative reporting requirement. Lastly, Staff would like to emphasize that one of the key benefits of DER generation is its peak load shaving ability. The potential to utilize the DER already on the grid to defer potential upgrades should provide downward pressure on the distribution budget and ratepayer impacts. Extracting this value to the fullest possible extent, by refining the PNL methodology to properly value the contributions of DERs while not compromising safety and reliability, would be in the public's interest.

3. *FERC Order 2222*

FERC Order 2222 allows third-party DER aggregators to bid distribution connected capacity directly into wholesale markets. Within the IDP Xcel noted that FERC Order 2222 would significantly impact the interconnection process and that DERMS will play a key role in meeting the order's requirements.³¹⁷

Xcel mentioned IDP Requirement No. 3.C.4 that requires information on anticipated impacts from FERC Order 841 and notes that the relevance of the order is increasingly limited.³¹⁸ In the Company's view, it would be more useful to revise this requirement to provide a high-level summary of FERC Orders, such as Order 2222 and their potential impacts instead of providing analysis of the same order. Staff notes that in the Distribution Data Workgroup there was consensus among Xcel, other utilities, and the Department to change this filing requirement. As noted in the Joint Briefing Papers, Staff believes this could be easily addressed through the proposed IDP Improvement Workgroup.

JSP recommended the Commission open a docket to address 2222 implementation and recommended a series of topics the docket could address.³¹⁹ The Commission recently opened Docket No. E002,015,017//CI-26-236 that will address the recommendations from JSP in a forthcoming notice; therefore, Staff does not summarize them here and does not include the decision option to avoid redundancy.

J. Non-Wires Alternatives Analysis

Non-Wires Alternatives (NWAs) are proposed projects meant to negate the need for a traditional projects like upgrading transformers or feeders to accommodate various risks such as overloading or losing function for transformers or feeders. Xcel examined 12 NWAs across their grid, all of which were either solar or a combination of solar and battery storage.

³¹⁷ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 38 (PDF p. 38).

³¹⁸ Xcel 2025 Integrated Distribution Plan, Chapter 7, p. 42 (PDF p. 325).

³¹⁹ JSP 2-28-26 Initial Comments, p. 3-7; JSP 4-23-26 Reply Comments, pp. 8-9

1. Methodology

Regarding NWAs in for the 2025 IDP, the Commission ordered Xcel to provide the following:³²⁰

3.E.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.

Additionally, Xcel was ordered to provide the following: ³²¹

- 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 nontraditional alternatives are considered prior to distribution system investments are made.

i. Project Type and Timeline

Xcel identified three different project types in their analysis: mandated projects, asset health and reliability projects, and capacity projects.

Xcel stated that mandated project are projects that “require the Company to relocate infrastructure within public rights-of-way to accommodate public initiatives, such as road widenings or realignments.”³²² The Company claimed that these projects are not ideal for NWA due to technical constraints and having to meet municipal or state funding timelines that they do not have control over.

Regarding asset health and reliability projects, Xcel stated there is a much higher risk that certain assets will fail if they don’t replace aging infrastructure which can cause outages. In these cases the customers would be temporally served through local islanding but would need to be hooked back up to the distribution system.

³²⁰ Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, September 16, 2024, Docket E002/M-23-452, Ordering Paragraph 3.E.1

³²¹ Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, September 16, 2024, Docket E002/M-23-452, Ordering Paragraph 3.E.2

³²² Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 23 (PDF p. 352).

Xcel considered capacity projects the most applicable for NWAs “because they address load deficiencies that can be deferred or mitigated by strategically placed DER.”³²³ Capacity risks include N-0 (substation transformers or feeders exceeding 75% of its threshold) and N-1 (feeder fails and load has to be redistributed to adjacent feeders). However, Xcel noted that due to the magnitude and duration of N-1 risks, they claimed that NWA projects addressing them are less viable.³²⁴

On timelines, Xcel stated that they assumed three years are necessary for implementation of NWA solutions but that they must be evaluated four years out since lead times for equipment necessary for traditional solutions require a minimum of four years. Xcel noted that these timelines allow for traditional solutions to be used in the case that a NWA fails or does not receive any bids.

In response, the Department stated that Xcel’s current framing of NWA capabilities is too narrow and should also consider reliability for NWAs.³²⁵ **(Decision Option 54)** The Department cited Minnesota Power’s (MP) 2025 IDP, wherein MP states that NWA can also improve reliability by enhancing circuit backup power service when large capital cost projects are needed for such capabilities.

In reply comments Xcel did not support the Department’s recommendation that the Company include reliability projects in its NWA analysis.³²⁶

Xcel explained that reliability needs arise suddenly and require an immediate response. Given that NWA analyses happen through a multi-year planning and budget cycle, customers would remain exposed to outages and operational risk. Thus, these urgent fixes must occur outside of the NWA process.

In reply comments, the Department stood behind its initial recommendation and stated that including reliability projects in the analysis does not force its implementation and excluding these projects limits planning option.³²⁷

ii. NWA Analysis Screening Process

Xcel created a six-step initial screening process for its NWA projects as shown in Figure 36.³²⁸

³²³ Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 24 (PDF p. 353).

³²⁴ Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 24 (PDF p. 353).

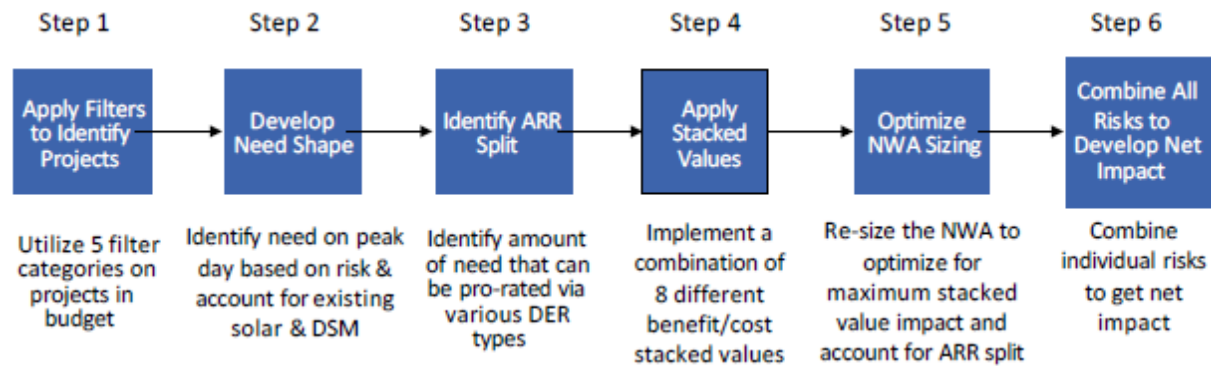
³²⁵ Department 2-27-26 Initial Comments, pp. 101-102.

³²⁶ Xcel 3-19-26 Reply Comments, Attachment A, pp. 31-32 (PDF pp. 39-40).

³²⁷ Department 4-23-26 Reply Comments, p. 78.

³²⁸ Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 22 (PDF p. 351).

Figure 36: Xcel Initial NWA Screen Steps



Step One requires the project to meet the following filters:

- Project Type: Capacity
- Timeline: in Year 3 or later of the planning cycle
- 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

Step Two develops a need shape or load reduction requirement to mitigate the targeted risk. Step Three determines the Avoided Revenue Requirement (ARR) split – the specific portion of the solar and battery storage Xcel will need to contract with the DER developer for to meet the need identified in the NWA. Step Four estimates eight key cost and benefit components that can be addressed at this stage. Step Five optimizes a mix of technologies to maximize the stacked value relative to the ARR split. Step Six identifies “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.”³²⁹

Xcel noted that Step Three of their analysis may lead to unrealistic outcomes regarding what the optimal NWA might be. The Company stated that their model will naturally lead to solutions that maximize solar PV. However, while Xcel included the TPS³³⁰ parameters in their modeling (which accounts for whether the grid will require upgrades to accommodate the generation) they did not have any variable for land availability or how expensive land leasing or purchasing may be.³³¹ The cost of land for purchase or for leasing is a significant component to the economics of any solar project – excluding this variable will, as Xcel indicated, lead to unrealistic outcomes as it will assume solar is both more affordable for third party developers as well as a possibility when it very well may not be given the location of a given site (not enough land available).

³²⁹ Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 22 (PDF p. 351).

³³⁰ The TPS is a standard that limits total available capacity to interconnect to 80% of the equipment rating plus daytime minimum load.

³³¹ Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 37 (PDF p. 367).

2. 2025 NWA Analysis Results

Xcel evaluated 12 projects with costs exceeding 2 million dollars as part of its NWA analysis and includes 9 below from 2025 (three were disqualified in the screening process).³³²

Table 10: 2025 NWA Candidate Projects

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
Reinforce 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 refers to whether a project's benefits may outweigh the costs. A positive value means that the project's benefits would exceed the costs, while a negative value means that the costs exceed the benefits. Xcel qualified that these numbers were desktop estimates and has several limitations as indicated in the methodology section.

3. Results of RFI and Plan for RFP

In the September 16, 2024 IDP Order, the Commission ordered Xcel to assess the feasibility of its planned Non-Wires Alternatives solicitation, its "ARR split" compensation, and to make a compliance filing reporting on the results of the RFI within 12 months of this order. Xcel issued an RFI on January 6, 2025 with responses a month later and issued a report to the Commission on April 1, 2025.

Xcel received zero response from the developer community and one response the Department of Commerce.

The Company stated that they plan to issue a Request for Proposals (RFP) for the Reinforce Parkers Lake feeders and Reinforce Coon Creek CNC TR1 to 50 MVA projects as they require the smallest amount of incremental DER.

The projects' NWA analysis suggests the following amounts of solar PV and battery storage in Table 11.

³³² Xcel 2025 Integrated Distribution Plan, Chapter 8, p. 3 (PDF p. 332).

Table 11: NWA Project DER Amounts

	Solar PV (MW)	Battery Storage (MW/MWh)
Reinforce Parkers Lake Feeder	7.0	2.0/8.5
Reinforce Coon Creek CNC TR1 to 50 MVA	31.2	8.12/88.28

Xcel's RFP timeline is as follows:

Table 12: Xcel RFP Timeline

Step	Target Date
Issue RFP	No later than June 1, 2026
RFP Response Due	July 31, 2026
Bid Review and Project Selection	September 30, 2026
RFP Report Submitted to the Commission (included in 2026 annual update report)	November 1, 2026

Fresh Energy highlighted that the concerns they expressed during the 2023 IDP remain present for the 2025 IDP.³³³ Fresh Energy remained unconvinced that NWA developers were willing to install DERs at their own expense while Xcel contributed the ARR split and pointed to the failed solicitation effort in Xcel Colorado's service territory.

Fresh Energy noted the zero responses from developers regarding Xcel's RFI expressed its concern that developers lacked interest in Xcel's proposed NWA projects and that such projects may not be feasible from a developer's standpoint.³³⁴ Based on the lack of responses to RFI and Xcel not accounting for land availability in its modeling Fresh Energy expressed doubt that the RFI will be successful. Fresh Energy recommended that if Xcel continues to receive no responses to its RFP, the Commission should require Xcel to work with stakeholders to reconsider its NWA approach (**Decision Option 55**).³³⁵

In reply comments, Xcel opposed this recommendation.³³⁶

ELPC/CEF/VS stated that they strongly support NWAs but note that the NWA approach has faced challenges, with very few NWAs having been built.³³⁷ ELPC/CEF/VS suggested that the Capacity*Connect program would effectively complement and possibly even replace the NWA process.

4. Staff Analysis

Xcel studied 12 NWA projects and seven were either deemed technically infeasible or disqualified early in the process. Of the five that were deemed technically feasible all of them

³³³ Fresh Energy 2-26-26 Initial Comments, p. 10.

³³⁴ Fresh Energy 2-26-26 Initial Comments, p. 12.

³³⁵ Fresh Energy 2-26-26 Initial Comments, p. 12.

³³⁶ Xcel 3-19-26 Reply Comments, Attachment A, pp. 31-32 (PDF pp. 39-40).

³³⁷ ELPC/CEF/VS 2-26-26 Initial Comments, p. 36.

were calculated to have net positive incremental impact. However, Xcel qualified this by stating that these values were desktop estimations and that there were many limitations and assumptions made in the creation of these numbers.

One of the larger, if not the largest assumption, was that the DER developers would be able to participate on an economic level. Developers would only be compensated for a pro-rated amount (only when the DER output is used to address the hours of load reduction requirement) and would also be required to build the solar PV in areas where the land values for leasing and purchasing may be quite high or very limited. Staff believes that the RFI on Xcel's business model for NWAs not receiving a single developer response indicates that this may be a non-starter for most developers who desire more certainty than this model would appear to provide.

Staff believes that not modeling for land availability or the cost of leasing or purchasing land is such a large oversight that it casts doubt on any of the final results and calculations Xcel used for its NWA BCAs. For example, the Coon Creek project identified above is for a substation in the middle of Coon Rapids, a Twin Cities suburb with little open land for the necessary 31.2 MW of solar identified in the analysis. Xcel has the tools necessary to avoid this kind of error through use of its LoadSEER spatial allocation forecasting tool which includes analysis of available land.

NWA solutions, at least the ones that utilize solar PV at the sizes Xcel is analyzing here, will require the buy-in and input from DER developers. Similar to how the Proactive Upgrade Process relies on some input in Xcel's modeling for the future due to information that only they would know, it may be beneficial to collaborate with DER developers on determining which areas of the grid are close to being economically feasible on a land-value basis. At the very least, it would be a somewhat fruitless endeavor for Xcel to continue to omit land-value in its modeling – few to zero NWA solutions are likely to be viable if this practice endures. Staff supports Fresh Energy's recommendation that Xcel reconsider its approach to NWA should the RFPs receive zero responses (**Decision Option 55**).

Staff also notes that **Decision Option 42**, discussed in Section F.4 (p. 69-70) could potentially integrate the NWA process with evaluation of discrete capacity projects.

Xcel is opposed to Department's recommendation that reliability and asset health be included in NWA analyses and stated that any solution would still have to be properly replaced in order to ensure reliability and the utility's obligation to serve. Staff notes that part of the issue at hand relates to how different projects are classified. Many distribution projects that are not specifically part of the asset health and reliability budget will improve reliability – for example, capacity projects improve reliability by avoiding overload caused outages. Projects that address unexpected failure or end-of-life equipment replacement (as is the case with the vast majority of Xcel's Asset Health and Reliability budget) are simply not candidates for NWA analysis as they require a replacement to continue basic grid functions. For example, a pole replacement program for failing distribution poles would not be a candidate for an NWA as poles are required to hold up the distribution wires serving customers. Similarly, a 70-year-old substation transformer at the end of its life must be replaced by another transformer to continue

supplying power. If there are specific reliability programs the Department feels would be suitable for NWA analysis, those should be identified with justification rather than a blanket assertion for the entire category.

K. Other Topics

1. *Proactive Capacity Investments*

The Department noted that in its initial comments on Xcel's Proactive Upgrade Proposal it had expressed concerns regarding the need for this process and preferred the Distribution System Reactive Upgrades Process (DSRUP) instead.³³⁸ The Department noted that because DSRUP only applied to cost allocation for generation, there was still an opportunity to pursue an analogous process for load. The Department recommended that the Commission order the Executive Secretary to open a working group tasked with developing updates to the DSRUP for load. However, in reply comments the Department focused its recommendations elsewhere and dropped this request.

2. *Geospatial Data Request*

The Department conducted a geospatial analysis of Xcel's spending by IDP budget category and by planning division.³³⁹ The Department asserted that the variation in forecasted distribution budget spending across planning divisions could not be driven by population growth alone. The Department thus requested several types of planning-division-level data from Xcel, including population data, quantitative measures of asset age and condition, quantitative customer data, and reliability performance and risk data.

The Department stated that without these data, "it was difficult to determine whether observed differences in distribution spending across Planning Divisions reflected underlying system needs, differences in customer growth, or inconsistent application of planning criteria."

Xcel did not support the Department's request for the Company to explain how a wide range of geospatial and demographic data were incorporated into its planning framework.³⁴⁰ The Company explained that data such as population and demographic trend data were not applied at the planning-division level and were not congruent with the electric system topology, while reliability metrics were monitored at the circuit level and equity issues were addressed in the SRSQ dockets. Xcel argued that the IDP focused solely on feeder- and substation-level planning and, as such, was not the appropriate venue for the other topics.

In reply comments the Department focused on its recommendations elsewhere and dropped this request.

³³⁸ Department 2-26-26 Initial Comments, pp. 114-115.

³³⁹ Department 2-26-26 Initial Comments, pp. 118-120.

³⁴⁰ Xcel 3-19-26 Reply Comments, Attachment A, pp. 33-34 (PDF pp. 41-42).

L. Summary of Staff Recommendations

Given the wide-ranging recommendations, Staff presents a consolidated set of recommendations. Stakeholder comments identified the following common themes that Staff's recommendations aim to address.

- Cost containment for a rapidly increasing distribution budget
- Increased transparency into how investment decisions are made at the program level
- Lack of clarity on how to consider alternatives to status quo planning standards and investments

While Staff's proposal amends and reworks many stakeholder recommendations, the end goal is for the outcomes to be similar without creating new processes or extensive filing requirements. As is the case in many Commission proceedings, Staff expects this to be an iterative process with improvements made in future years. Table 13 provides a comparison of where Staff has offered new decision options to replace and address stakeholder recommendations.

Table 13: Comparison of Staff and Stakeholder recommendations

Staff Recommendation	Stakeholder Recommendation
Decision Option 4 Establish a permanent standing IDP improvement workgroup	Decision Option 3
Decision Option 5 Refer a series of topics to the IDP Improvement Workgroup for development, including: • Modify existing filing requirements around forecast and load scenarios analysis • Developing updated financial information filing requirements for increased transparency, including a variance analysis • The incorporation of information on Xcel's planning standards into the IDP filings	Decision Option 7 Decision Option 37 Decision Option 40.a Decision Option 19
Decision Option 17 Decision Option 18 Require filing of CBAs for discretionary programs in rate cases	Decision Options 9-16
Decision Option 22 Hold a technical workshop with assistance from LBNL on valuing reliability in distribution proceedings	Decision Option 20 Decision Option 21 Decision Option 23
Decision Option 31 Require utilities to file wildfire mitigation plans by a specific date in new, utility specific dockets. As part of the initial filings, the Commission could determine the procedural treatment for WMPs. Staff also supports Decision Option 33 , with the exception of subpart l, and offers subpart o as an alternative to subpart n.	Decision Options 32-33



Decision Options 41-45, 37 Improve transparency into Xcel's planning standards and processes through a series of workshops, an independent engineering review, and requiring additional justification for large capacity projects in rate cases	Decision Options 35-40 Decision Option 46
Decision Option 47 Require Xcel to provide longer term information on proposed grid modernization investments in future rate cases and IDPs.	

In addition to the Staff written options above, Staff has no concerns from an implementation standpoint with the following decision options:

- Decision Options 1 or 2
- Decision Option 6
- Decision Options 24 through 30
- Decision Options 49 through 51

Staff also supports the following stakeholder decision options:

- Decision Option 48
- Decision Option 52
- Decision Option 53
- Decision Option 55

While this set of recommendations is likely not any one organization's preferred pathway, Staff believes it will result in constructive outcome that all participants in the docket share: a safe, affordable, reliable distribution system that advances customer adoption of DERs and electrification.



V. DECISION OPTIONS

A. Acceptance and Process

The Commission must adopt Decision Option 1 or 2.

1. Accept Xcel Energy's 2025 IDP Report as in compliance with IDP Filing Requirements and order points. Acceptance of the 2025 IDP has no bearing on prudence nor certification under Minn. Stat. § 216B.2425, subd. 3.

(Support: Fresh Energy, Minneapolis)

2. Accept Xcel Energy's Integrated Distribution Plan as in compliance with IDP Filing Requirements and order points, contingent on the Company making additional filings as noted in **Decision Options 52** and **53**. Acceptance of the 2025 IDP has no bearing on prudence nor certification under Minn. Stat. § 216B.2425, subd. 3.

(Support: ELPC/VS/CEF)

The Commission may adopt Decision Option 3 or 4.

3. Delegate authority to the Executive Secretary to Direct the Distribution Data Reporting Work Group to identify IDP filing requirements that Xcel and intervenors agree can be removed.

(Support: Department; ELPC/CEF/VS; Fresh Energy; Mpls; JSP)

OR

4. Delegate authority to the Executive Secretary to establish a standing IDP Improvement Workgroup for Xcel Energy. Delegate authority to the Executive Secretary to approve via notice amended IDP filing requirements if agreement among stakeholders is reached.

(Staff)

If the Commission adopts Decision Option 4 it may also adopt Decision Option 5.

5. Refer the following topics to the IDP Improvement Workgroup for development of amended or new filing requirements with a goal of completion so they can be incorporated into the 2027 IDP:
 - a. Reporting actual historic peak load in future IDPs and a variance analysis to explain deviations from prior forecasts
 - b. Refinement of the forecast and scenario filing requirements for future IDPs
 - c. Conversion of permanent order points into filing requirements
 - d. A variance analysis on distribution spending that deviates from the forecasted amount by a certain percentage
 - e. A better breakdown of major distribution programs, similar to FE IR 34 and utility rate case programs
 - f. Actual spend for individual discrete capacity projects
 - g. Breakdown of capital expenditures vs capital additions
 - h. Inclusion of Xcel's Planning Standards and changes to the standards

(Staff)

B. Forecasting and Scenario Analysis

The Commission may adopt and combination of Decision Options 6-8.

Decision Option 5.a-b is an alternative to Decision Option 7.

6. Require Xcel to submit a compliance filing in this docket within six months of the order that identifies non-DERMS changes the Company can make in the near term to better integrate DSM into distribution planning.
(Support: Fresh Energy. Opposed: Xcel)
7. Create a new IDP filing requirement to provide a comparison of forecast accuracy for the forecast scenario or scenarios Xcel uses for budgeting in Xcel's LoadSEER forecasts compared to actuals. Forecast accuracy should adjust model parameters to actual observed conditions to determine the accuracy of the forecast.
(Support: Department; ELPC/CEF/VS. Oppose: Xcel)
8. Require Xcel to apply a local electrification overlay be developed and piloted in the next IDP to show the value of local data inputs during modeling and planning.
(Support: Mpls. Opposed: Xcel)

C. Budget – Cost Benefit Analysis

The Commission may choose any combination of the following decision options.

9. Require Xcel to make the following changes to its CBAs:
 - a. Use ex-ante or forward-looking CBAs and estimate the customer costs and benefits of planned program expenditures.
 - b. Reflect the present value of costs (measured as revenue requirements) and benefits over the life of the assets in CBAs.
 (Support: Fresh Energy; ELPC/CEF/VS; Xcel 32.b. Opposed: Xcel 32.a)
10. Require Xcel to perform all programmatic cost benefit analyses to calculate costs and benefits as follows:
 - f. All benefits and costs should use only marginal calculations;
 - g. All benefits and costs should be calculated in the present value of costs;
 - h. All cost calculations should be quantified over the full lifecycle of the program and its alternative case with no program expenditures;
 - i. All benefit calculations should avoid averaging and should be appropriately normalized unless Xcel can demonstrate why normalization is not necessary; and
 - j. Where statistical analysis is used, Xcel's models should account for variance that can be explained by other factors than the primary variable of interest.
 (Support: Department. Opposed: Xcel)
11. Require Xcel to re-file the cost benefit analyses for the End-of-Life Replacement Breakers and Grid Reinforcement programs to adhere to **Decision Option 10**.
(Support: Department)



12. In future IDPs or rate case applications require Xcel to include a forward-looking CBA demonstrating that the customer benefits exceed the costs of its planned Grid Reinforcement expenditures.

(Support: Fresh Energy. Opposed: Xcel)

13. Order Xcel to provide a cost benefit analysis of at least three discretionary programs with a goal to review a total five-year budget of at least \$250 million. Xcel shall meet its \$250 million goal unless the Company can demonstrate that no portfolio of projects can meet the goal under the following screening criteria:

- a. Clear, quantifiable benefit streams (such as avoided Customer Minutes Out (CMOs) or targeted operations and maintenance (O&M) savings),
- b. Stable and reliable data inputs, and
- c. No mandatory components triggered by inspection thresholds or safety requirements.

(Support: Department; CUB; OAG; JSP. Opposed: Xcel)

14. Order Xcel to provide an update to the cost benefit analysis for any programs in **Decision Option 13** and the ELR and Grid Reinforcements programs ten years after the initial presentation of the cost benefit analysis.

(Support: Department; CUB; JSP. Opposed: Xcel)

15. Create a new IDP filing requirement for Xcel Energy which states:

For all new distribution spending projects and programs with an estimated historical or forecasted five-year budget of \$25 million or greater Xcel must, at minimum, provide the following information:

- a. Estimated cost or range for the project/program;
- b. Consideration of feasible alternatives to the proposed spending;
- c. Quantitative estimation of expected outcomes; and
- d. Sensitivity analysis of cost and outcome assumptions.

(Support: Department; ELPC/CEF/VS; Fresh Energy; CUB; Mpls; OAG; JSP. Opposed: Xcel)

16. Order Xcel to report five years of actual outcomes compared to forecasted outcomes for all new spending projects with a five-year budget over \$25 million, that were approved for cost recovery since 2021, in the IDP. Forecasted outcomes correspond to the data used to substantiate a cost recovery request, which may include, but is not limited to:

- a. Capital cost savings,
- b. Operational cost savings,
- c. Reliability benefits,
- d. Enhanced customer experience.

(Support: Department; ELPC/CEF/VS; JSP; CUB. Opposed: Xcel)



17. In all future rate cases require Xcel Energy to include a cost benefit or least cost/best fit analysis for any discretionary distribution capital programs that average more than \$4 million per year in capital expenditures during the term of the filed rate case.

(Staff)

18. In future IDPs, require Xcel Energy to file any cost benefit or least cost/best fit analyses for discretionary distribution capital investments that were performed for its most recent rate case as an appendix or attachment.

(Staff)

D. Reliability

Asset Health and Reliability Budget

The Commission may adopt either or both Decision Options 19 and 20

19. Require Xcel Energy to provide more transparency into its methodology for prioritizing Asset Health and Reliability (AH&R) projects/programs and establishing associated budgets.

(Support: Fresh Energy. Opposed: Xcel)

20. Require Xcel Energy to develop a methodology for estimating the expected reliability improvements from its AH&R expenditures.

(Support: Fresh Energy. Opposed: Xcel)

Value of Reliability

The Commission may choose Decision Option 21 or 22.

21. Delegate authority to the Executive Secretary to initiate a new proceeding to discuss the appropriate value of reliability. The initial comment period should address:

- a. The valuation of the cost of unserved energy;
- b. The use of price caps for the cost of unserved energy;
- c. Forecasting methodologies for reliability benefits;
- d. Appropriate uses cases for the value of reliability; and
- e. The potential to employ different values of reliability by customer class.

(Support: Department; ELPC/CEF/VS; Fresh Energy; Mpls)

OR

22. Delegate authority to the Executive Secretary to hold one or more technical workshops facilitated by Commission Staff on how to value reliability in distribution proceedings.

(Staff)

Decision Option 23 may be adopted with Decision Option 21. Decision Option 22 would address it as part of the workshop process.

23. Require Xcel to explore use of the Interruption Cost Estimate 2.0 methodology from Lawrence Berkeley National Laboratory to identify and prioritize investments in low-income and other vulnerable communities.

(Support: ELPC/CEF/VS)

Targeted Undergrounding

The Commission may adopt any combination of Decision Options 24 through 30

24. Prohibit Xcel from implementing any targeted undergrounding projects until the comment process under **Decision Option 21** has concluded.
(Support: Department. Opposed: Xcel)
25. Require Xcel to perform full cost-benefit analysis for all targeted undergrounding projects scheduled beyond the 2026 pilot phase, which must incorporate O&M savings (including avoided vegetation management and storm restoration costs), and use site-specific construction estimates and benefit calculations.
(Support: Department. Opposed: Xcel)
26. Require Xcel to contract with an independent consulting firm that specializes in vegetation management to perform a comprehensive optimization of the Company's current vegetation management strategy.
(Support: Department)
27. Approve Xcel's site selection criteria for targeted undergrounding with the following modifications:
 - a. Require Xcel to demonstrate a minimum BCR of 1.25, using tools like the ICE, to financially justify each individual project prior to approval.
 - b. Limit or strictly prioritize undergrounding to sites where existing overhead infrastructure is fully depreciated to prevent stranded costs from premature retirements.
 - c. Require the formal quantification of alternatives, specifically enhanced vegetation management, FLISR deployment, and backlot O&M expenses, during site selection to ensure undergrounding is the most economical choice.*(Support: Department. Opposed: Xcel)*
28. Require Xcel to integrate equity considerations explicitly and transparently into its targeted underground program, including:
 - a. Require the Company to explore using the Interruption Cost Estimate 2.0 Calculator from Lawrence Berkeley National Laboratory to inform this integration.
 - b. Require the Company to incorporate insights from its ongoing independent third-party evaluation.*(Support: ELPC/CEF/VS; Department. Opposed: Xcel)*
29. Require Xcel to integrate equity considerations explicitly and transparently into its targeted underground program from the start to ensure that communities facing disparities in reliability appropriately benefit in a timely manner.
(Support: Department)



30. Require Xcel to report annually on its targeted undergrounding program, including:

- a. The number of undergrounding projects
- b. Number of projects in Environmental Justice areas
- c. Actual undergrounding project costs
- d. Drivers for projects (engineering, equity, other)
- e. Description of community engagement efforts

(Support: ELPC/CEF/VS; Department. Opposed: Xcel)

E. Wildfire Mitigation

The Commission may adopt either Decision Option 31 or 32.

If the Commission adopts either of the above options, it should adopt all or part of Decision Option 33

The Commission may also adopt Decision Option 34 with any of the above.

31. Require Xcel Energy to file a Wildfire Mitigation Plan in a new docket by _____.
(Staff)

OR

32. Require that Xcel file any future (outside of the current rate case's test and planning years) wildfire mitigation proposals with the Commission as a comprehensive Wildfire Mitigation Plan as an attachment or supplement to the Company's IDP starting in 2027.

(Support: Department; ELPC/CEF/VS)

33. The Wildfire Mitigation Plan shall include the following:

- a. A description of the intent of the Company in mitigating wildfire risk (i.e. mitigating utility-caused wildfires/minimizing liability or mitigating fire damage to utility assets).
- b. A definition of "wildfire" as it is used for utility identification, planning and mitigation.
- c. A discussion of its risk modelling, mapping and prioritization process within its Wildfire Mitigation Plan.
- d. Quantification of actual wildfire risk in Xcel's territory based on the probability and size of a fire, and land use.
- e. Xcel's Minnesota wildfire risk should be compared to other reliability and safety risks experienced by Xcel in Minnesota as well as the wildfire risk experienced in Xcel's other jurisdictions.
- f. Quantification of wildfire damages by event size, including Xcel-owned and other property damage, applicable liability, and any other costs Xcel deems reasonable to include.
- g. The most recent version of its wildfire risk map with a narrative explanation of the highest risk areas, and any changes from the last iteration of the Wildfire Mitigation Plan.
- h. Reporting on the number and locations of wildfires experienced in its territory, the number of outages caused by wildfire, and the average length of wildfire-related outages.



- i. Reporting on the efficacy of its wildfire mitigation strategy in reducing wildfire-related outages (i.e. After deployment of the rate-case-approved wildfire mitigation measures, wildfire-related outages in Xcel's territory decreased 50 percent; the number of wildfires in Xcel's service territory decreased from 100 to 50 since the filing of the Company's last IDP resulting in approximately 10 fewer outages)
- j. Discussion of its use of its Public Safety Power Shutoff Program, including the number of PSPS outages, cause of the PSPS outage, average length of a PSPS outage, if/how notice was provided to customers, and measures the Company employs to protect customers that are medically dependent on electric service.
- k. The Wildfire Safety Operations Playbook, the PSPS Playbook, and the PSPS Communications Playbook as attachments or provide the location where the Playbooks can be accessed.
- l. A full cost benefit analysis of any proposals.
- m. The available years of wildfire-related outage data.
- n. An integration of the locational information from its medically necessary equipment certification form into its wildfire mitigation plan.
- o. The number of customers with medically necessary equipment certification forms in its WMP and steps the Company will take to mitigate damage from outages before, during, and after wildfire-related damage may occur.

(Support: Department; ELPC/CEF/VS; Xcel A-K, M. Opposed: Xcel L, N)

34. Pursuant to Minn. Stat. § 216B.62, subd. 8, request that the Commissioner of the Department of Commerce seek authority from the Commissioner of Management and Budget to incur costs up to \$300,000 for specialized services to assist with any proceedings related to the review of wildfire mitigation plans for Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association.

(Support: Department)

F. Changes to Distribution Planning Process

Decision Options 35 and 36 creates the Department's Planning Standard Review Process.

Decision Options 38 and may also be adopted as part of this package

Decision Options 41-45 form Staff's alternative.

Decision Option 27 may be adopted with either pathway.

Decision Option 46 may be adopted with the Department's PSRSP. Staff's Decision Option 45 already incorporates this decision option.

35. Delegate authority to the Executive Secretary to create a formal workgroup and planning standard review process that shall:
- a. Identify the main system planning standards that Xcel uses for each Commission approved review topic
 - b. Select one or more planning standards, in agreement with intervenors, to review before the next IDP
 - c. Set alternative system planning scenarios to analyze, in agreement with intervenors



- d. Perform a quantitative analysis of alternative system planning standards that measure estimated costs and benefits of alternative system planning standards
 - e. Require Xcel to present the results of steps A-D in the next IDP cycle
 - f. Request comments to approve, modify, or reject the revised system planning standards for each Commission-approved review topic.

(Support: Department; ELPC/CEF/VS; Fresh Energy; JSP; CUB; Mpls; OAG. Opposed: Xcel)
- 36. Establish the following system planning standard review schedule, with each phase to repeat every eight years:
 - a. 2027: Capacity
 - b. 2029: Reliability and Asset Health
 - c. 2031: Grid Modernization, Distributed Energy Resources, and Operation and Maintenance
 - d. 2033: Budgeting

(Support: Department; ELPC/CEF/VS; Fresh Energy; JSP; CUB; Mpls; OAG. Opposed: Xcel)
- 37. Require Xcel to disclose all changes to its system planning standards in its IDP.
(Support: Department; ELPC/CEF/VS; CUB; JSP; Xcel)
- 38. Delegate Authority to the Executive Secretary to establish an ad hoc system planning standard review process that shall:
 - a. Allow any intervenor to request a planning standard review;
 - b. Set the parameters that shall be reviewed;
 - c. Require the Commission to approve, modify, or reject the request for a planning standard review, limited to one such planning standard review per IDP cycle;
 - d. Require Xcel to present the results of the planning standard review in its next IDP; and
 - e. Request comments to approve, modify, or reject Xcel's system planning standard.

(Support: Department; ELPC/CEF/VS; JSP; CUB; Mpls; OAG. Opposed: Fresh Energy, Xcel)
- 39. Pursuant to Minn. Stat. § 216B.62, subd. 8, request that the Commissioner of the Department of Commerce seek authority from the Commissioner of Management and Budget to incur costs up to \$1,175,000 for specialized services to assist with any proceedings related to the review of distribution planning standards review for Xcel Energy.
(Support: Department. Opposed: Xcel)
- 40. Require a review of the following capacity planning standards, to be presented in Xcel's 2027 IDP:
 - a. Capacity forecasting and accuracy
 - b. N-0 forecast uncertainty margin and the use of AMI or other actual data
 - c. N-1 probability of coincident peak load and N-1 contingencies
 - d. N-1 screening based on cost effectiveness
 - e. Equipment ratings during N-1 emergencies



- f. Sizing new assets for future load growth
- g. Capacity Risk Framework
- h. Project Prioritization

(Support: Department; ELPC/CEF/VS; JSP. Opposed: Xcel)

41. In all future rate cases require Xcel Energy to provide forecast support for discrete capacity projects over \$2 million in total cost.

(Staff)

42. Direct the Proactive Grid Upgrade Workgroup to discuss, and potentially develop, a process to analyze near term capacity upgrades based on the existing Proactive Grid Upgrade Framework.

(Staff)

43. Require Xcel Energy to conduct an independent engineering review of its distribution system standards and submit the report with its IDP due Nov 1, 2027. Xcel shall work with Commission Staff to determine the independent engineer, which standards shall be reviewed, and to what extent.

(Staff)

44. Delegate authority to the Executive Secretary to convene one or more technical workshops facilitated by Commission Staff, focused on the engineering and risk-based topics from the Department's proposed review of Xcel's Capacity Standards:

- a. N-0 forecast uncertainty margin and the use of AMI or other actual data
- b. N-1 probability of coincident peak load and N-1 contingencies
- c. N-1 screening based on cost effectiveness
- d. Equipment ratings during N-1 emergencies
- e. Sizing new assets for future load growth
- f. Capacity Risk Framework

(Staff)

45. Delegate authority to the Executive Secretary to hold one or more joint stakeholder meetings with the DGWG, the DSRUP Workgroup, and the Proactive Workgroup to discuss and provide recommendations for Xcel Energy's prioritization process and criteria for discrete distribution capital investment projects. As part of this process, stakeholders should also discuss and provide recommendations on how to incorporate equity informed prioritization criteria as recommended by ELPC/CEF/VS on page 20 of their April 23, 2026 reply comments.

(Staff)

46. Require Xcel to submit a compliance filing before Xcel's 2025 IDP, which:

- a. Establishes equity-informed prioritization criteria for distribution investments. Xcel shall develop and implement systematic criteria that prioritize investments addressing documented service disparities. The Company should weight these criteria appropriately in its distribution project scoring and prioritization



processes.

- b. Integrates equity requirements into the IDP process. Xcel must demonstrate in its IDP filings how it will systematically and transparently incorporate equity considerations into distribution planning and investments.
- c. Implements transparent reporting on equity outcomes. Xcel must report on reliability improvements and infrastructure investments by environmental justice area, income level, and racial composition in its Safety, Reliability, and Service Quality annual reports, just as the Company reports on reliability or other dimensions of utility performance. This reporting should demonstrate whether rate funded investments are systematically addressing documented disparities or perpetuating inequitable service patterns.

Xcel shall discuss its implementation of these requirements in its 2027 IDP.

(Support: ELPC/CEF/VS; Department; Fresh Energy; JSP. Opposed: Xcel)

G. Grid Modernization

The Commission may adopt Decision Option 47

- 47. Require Xcel to include the forecasted lifetime budget for multi-year grid modernization investments in future rate cases and IDPs and a description of any future associated investments outside the scope of the current rate case or IDP that will be needed to fully implement the proposed grid modernization technology.

(Staff)

H. DER Management System (DERMS)

The Commission may adopt Decision Option 48.

- 48. Accept Xcel's DERMS roadmap, and require Xcel to continue DERMS development and implementation, and require Xcel to report on changes and updates to DERMS development and implementation plans, current and future use cases, budgets, and stakeholder engagement activities in its 2027 Integrated Distribution Plan filing.

(Support: ELPC/CEF/VS; CEE)

The Commission may adopt some, all, or none of Decision Options 49 through 51

- 49. Direct Xcel to collaborate with stakeholders to develop and file in a separate docket a proposal for a complementary market-driven behind-the-meter Distributed Power Plant (or Virtual Power Plant) program by July 1, 2027.

(Support: ELPC/CEF/VS)

- 50. Order Xcel to begin a pilot program to test localized distribution grid benefits from its Aggregator Distributed Energy Resource Management System. At minimum the pilot should:

- a. Test different incentive levels to determine the optimal incentive structure;
- b. Test at least two controllable load types;
- c. Provide a cost-benefit analysis of localized distribution grid benefits compared to standard distribution grid upgrades.

(Support: Department. Opposed: Xcel)



51. Order Xcel to develop and propose a pilot to explore dual fuel load control applications to manage system impacts of electrified residential space heating in a proceeding determined by the Commission.

(Support: CEE; Department. Opposed: Xcel)

I. DER Integration

Flexible Interconnection

The Commission may adopt Decision Option 52

52. Require Xcel to:

- a. Revise its Flexible Interconnection proposal to develop and implement Static FI in the near term, prior to or in parallel with implementing full, Dynamic FI.
- b. Order Xcel to file, by December 31, 2026, a report on their FI efforts and plans in this docket, and include a specific update on their progress towards implementing static FI including elements such as technical standards, customer-facing documentation, and enablement timelines;
- c. Order Xcel to include updated information on Flexible Interconnection in its 2027 IDP, including the number of new load and DER connections utilizing static FI, the capacity made available as a result, and progress towards dynamic FI rollout;
- d. Require Xcel to incorporate and otherwise address discussions and learnings from the DGWG process in its 2026 and 2027 filing; and,
- e. Require Xcel to review materials from Ameren and CHARGED, who have worked extensively on Flexible Interconnection and present key considerations. Require Xcel to incorporate these considerations into its program design and address these materials in its 2026 report and 2027 IDP.

(Support: ELPC/VS/CEF; JSP; Department; Fresh Energy. Opposed: Xcel)

Planned Net Load

The Commission may adopt Decision Option 53

53. Order Xcel to file, by December 31, 2026, an interim update that:

- a. Demonstrates that it has given due consideration to the alternative PNL methodologies presented by stakeholders and substantively evaluates those methodologies
- b. Provides specific details about the seasonal dependability factors, including the percentages it plans to use and which months would apply to each season; and
- c. Analyzes the impacts of those seasonal dependability factors
- d. An analysis of the pros, cons, limitations, and opportunities for each of the different methodologies and which they may incorporate in the future and why.

(Staff addition)

Require Xcel to address its implementation of these topics in its 2027 IDP.

(Support: ELPC/CEF/VS; Department. Opposed: Xcel)

J. Non-Wires Alternatives

The Commission may choose any combination of Decision Options 54 and 55

54. Require Xcel to consider reliability projects in its Non-Wire Alternatives Analysis.

(Support: Department. Opposed: Xcel)

55. If Xcel receives no responses to its NWA RFP, require the Company to work with stakeholders and developers to reconsider its approach to NWAs.

(Support: Fresh Energy)



Technical Memo for Minnesota Public Utilities Commission Staff
Distribution Planning and Design Standards¹
June 12, 2026

BACKGROUND

The Minnesota Department of Commerce (DOC) filed a recommendation that the Minnesota Public Utilities Commission (PUC) establish a formal Planning Standards Review Process in Xcel Energy's 2025 Integrated Distribution Plan (IDP) proceeding (Docket No. 25-142). The Department and supporting intervenors propose an eight-year review cycle that would identify, evaluate, and ultimately require Commission approval of the utility's core capacity, reliability, and asset planning standards. This technical memo surveys the national landscape for such regulatory practices, standard-setting bodies, and applicable definitions of engineering judgment to assist Commission staff in assessing such a process.

For the first proposed cycle, addressing capacity, the DOC recommends focusing on the following planning standards:

- A. Capacity forecasting and accuracy
- B. N-0 forecast uncertainty margin and the use of AMI [advanced metering infrastructure] or other actual data
- C. N-1 probability of coincident peak load and N-1 contingencies
- D. N-1 screening based on cost-effectiveness
- E. Equipment ratings during N-1 emergencies
- F. Sizing new assets for future load growth
- G. Capacity risk framework
- H. Project prioritization

REQUEST

Minnesota PUC staff requested technical assistance on the following aspects of the DOC's proposal.

1. Utility Planning and Design Standards
 - A. Are there any state utility commissions that engage in the review and approval of specific planning standards for utility distribution systems, including approval of engineering standards? Are those proceedings or standards published anywhere?
 - B. Are there any national entities that issue or develop "planning standards" for utilities?

¹ Contributors: Paul De Martini, Newport Consulting Group; Guillermo Pereira and Lisa Schwartz, Lawrence Berkeley National Laboratory (LBNL)

- C. Is there a widely used definition of "good engineering judgment" as it pertains to the electric system?
2. Review the DOC's proposed capacity planning standards and provide examples from other jurisdictions
3. Alternative to forming a working group to assess Xcel Energy's engineering standards and decision-making practices
4. Best practices for assessing a utility's forecasted vs. actual distribution system spending outside of a rate case

1. Utility Planning and Design Standards

A. Are there any state utility commissions that engage in the review and approval of specific planning standards for utility distribution systems, including approval of engineering standards? Are those proceedings or standards published anywhere?

Minnesota: Existing NESC Adoption. The PUC has previously incorporated engineering standards by reference into its rules, a foundation on which a broader IDP standards review process could be built. For example, [Minn. R. 7835.2100](#) requires that utility interconnections with qualifying facilities comply with "*the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers,*" and that qualifying facilities comply with the National Electrical Code (NEC).

Also, the PUC's enabling statutes, Minn. Stat. §§ [216A](#) through [216B](#), authorize the Commission to "*create and maintain a regulatory environment that ensures safe, reliable and efficient utility services at fair and reasonable rates,*" providing broad authority to apply engineering standards to IDP requirements.

Examples From Other Jurisdictions

While we are not aware of any state public utility commission (PUC)² that adopted a framework mirroring the DOC's proposed planning standards review cycle, a growing body of state practices support regulatory application of specific distribution planning and engineering standards. The following are illustrative examples.

Safety and Construction Engineering Standards - California

The California Public Utilities Commission (CPUC) provides a well-developed model of formal commission approval of distribution engineering standards. CPUC [General Order 95](#) (overhead line construction), [General Order 128](#) (underground construction), and [General Order 165](#) (inspection cycles) establish detailed engineering requirements — covering conductor ratings, clearances, pole loading calculations, and construction methods — that are promulgated and periodically revised through formal rulemakings. The Commission approves any changes to the requirements. For example, Rulemaking [R.17-10-010](#), culminating in Decision [20-01-010](#), significantly revised pole loading and fire-hardening standards in General Order 95 following unanimous stakeholder consensus. Importantly, California adopted its own requirements rather than incorporating the National Electrical Safety Code (NESC), which most other states recognize.

² Also called public service commissions (PSCs).

Safety and Construction Engineering Standards - NESC Adoption in Other States

A substantial majority of states have formally adopted NESC American National Standards Institute (ANSI) Standard C2, published by IEEE, as a binding construction and safety standard for electric transmission and distribution (T&D) facilities. Adoption is typically through commission rulemaking or incorporation by reference into the state administrative code. As of 2023, approximately 90 percent of U.S. states use the NESC for regulatory purposes. [IEEE's NESC State Adoption Survey \(2017\)](#) documents the specific administrative codes and statutes that each state commission has incorporated into its jurisdiction. Notable examples follow.

- **Florida PSC.** [Rule 25-6.034](#) expressly adopts the NESC by reference as the applicable safety standard for T&D facilities, subject to the Commission's safety jurisdiction, binding all investor-owned electric utilities, rural electric cooperatives, and municipal electric systems. The Commission updates this rule through formal rulemaking for each release of a new edition of the NESC. For example, a [2024 proposed rulemaking](#) adopted the 2023 NESC (C2-2023) in place of the prior 2017 edition.
- **Michigan PSC.** Administrative Code [R 460.813](#) (Standards of Good Practice; Adoption by Reference) incorporates Parts 1, 2, and 3 of the NESC as binding standards of good practice for electric utilities. The MPSC has gone further than most states, promulgating detailed service quality, reliability, and technical standards in Michigan Administrative Code Rules, specifically [R 460.813](#) covering voltage standards, power factor requirements, and distribution system equipment specifications. A [2020 MPSC Benchmarking Study](#) examined these technical standards against those of other states and is a useful comparative reference for the Minnesota PUC's proceeding.
- **Pennsylvania PUC.** PUC 52 Pa. Code § [57.28](#) requires electric distribution companies to comply with NESC standards, established through formal Commission rulemaking. The rulemaking record published in the [Pennsylvania Bulletin](#) reflects substantive stakeholder engagement on which provisions constitute minimum versus aspirational standards.
- **Wisconsin PSC.** [Admin. Code Chapter PSC 114](#) (State Electrical Code) adopts the NESC and establishes technical construction standards for electric utilities, authorized under Wis. Stat. §§ [196.02\(1\) and \(3\)](#), [196.74](#). Wisconsin's approach is notable for combining NESC adoption with commission-issued reliability performance standards to create an integrated engineering and planning standards framework.
- **U.S. Department of Agriculture Rural Utilities Service (RUS).** The RUS, which provides financing for electric cooperatives, requires NESC compliance as a condition of loans under 7 C.F.R. § [1724.50](#). This federal requirement effectively mandates the adoption of engineering standards for a substantial portion of rural distribution systems, creating a *de facto* national minimum standard for these utilities.³

Reliability Metrics as Approved Planning Performance Standards

Several commissions have formally approved numerical reliability planning standards — a form of distribution planning standard closely related to the capacity parameters proposed in Docket 25-142:

- **Maryland PSC** adopted binding [SAIDI and SAIFI standards](#) through rulemaking in December 2015, revised and extended through 2027 in subsequent proceedings. The rules set allowable outage durations as regulatory targets that utilities must plan to meet.

³ In Minnesota, that includes Dakota Electric, subject to PUC IDP requirements.

- **Illinois Commerce Commission (ICC)** approved a bespoke reliability metric methodology that extends measurement to outages exceeding one minute, rather than adopting the IEEE 1366 standard of five minutes ([Docket No. 22-0063, September 2022](#)). The ICC subsequently applied these approved metrics as performance benchmarks in its review of ComEd's and Ameren's Multi-Year Integrated Grid Plans. Review of these plans explicitly encompasses the investment and planning strategies utilities use to meet those metrics.
- **New York PSC's** Reforming the Energy Vision proceeding and associated Distributed System Implementation Plan (DSIP) framework establish planning objectives and metrics that utilities must satisfy in their distribution plan filings, which the Commission reviews. The 2024 ["Grid of the Future" proceeding](#) (Case [24-E-0165](#)) extends this to operational standards for distribution systems.

Regulatory Requirements for Planning Criteria and Standard-Related Information in Distribution Plan Filings

While not specifying standards that regulated utilities must use in distribution plan filings, some Commissions require that utilities provide planning criteria and standard-related information. This can contribute to improved regulatory oversight of utility planning criteria and standards that shape near-term investment decisions. Planning requirements in place in Maine and Oregon, described below, illustrate this approach.

- **Maine.** [Integrated Grid Plan filings must include](#) information on *"distribution planning criteria and current practices for needs identification (e.g. reliability/cost analysis, equipment ratings methodology, contingency planning requirements)."* (Attachment C, p.3) Utilities [Central Maine Power](#) and [Versant Power](#) submitted their plans in December 2025 and January 2026, respectively, including information to address the above requirement.⁴ Here's how Versant Power describes its planning criteria to identify grid needs:
 - *"A substation transformer's load exceeding 90% of its top rating.*
 - *The power through a distribution device (e.g., regulators, circuit breakers, reclosers, and fuses) exceeds 90% of its rating.*
 - *The load on a distribution conductor exceeds 90% of its rating.*
 - *The voltage at any point on a distribution feeder or device exceeds Versant's operating voltage criteria."* (p. 86)
- **Oregon.** [Distribution system planning \(DSP\) guidelines](#) updated in 2024 require regulated electric utilities to provide a summary for each planned investment and expenditure exceeding \$2 million. The guidelines direct utilities to include in the narrative information on any standards, company policies, or other requirements prompting the proposed project.

Information on planning standards in PGE's 2024 [DSP](#)⁵ included the following:

- **Equipment standards:** *"For substation transformers, our planners will determine the necessary transformer capacity based on standardized transformer sizes so we can accommodate the loading needs identified in the study. We have standardized transformer sizes (28 MVA and 50 MVA), however non-standard sizes may be required based on specific needs of a customer and/or a location"* (p. 112).

⁴ No order has been issued on Central Maine Power or Versant's plan as of May 13, 2026.

⁵ The Commission accepted the plan in its [October 21, 2025, Order](#).

- **Planning criteria:** *“Planning criteria for our distribution feeders require associated feeder getaways, mainlines and voltage regulators not to exceed 67 percent of their seasonal thermal limits or 12 MVA, whichever is lower, under system normal, or N-0, conditions. For most standard feeders, this equates to two-thirds normal capacity of a standard feeder main line. Under N-1 conditions, distribution feeders can load up to their seasonal thermal limits. For both N-0 and N-1 conditions, the distribution system is planned such that voltage at the customer meter is maintained within 5 percent of the customer’s nominal service voltage, which for residential customers is typically 120 volts”* (p. 165).

PacifiCorp's recently filed 2026 [DSP](#)⁶ includes information on its planning standards and engineering approach, such as describing how field engineers apply engineering standards to conduct distribution planning studies: *“PacifiCorp’s study methodology is based on the Distribution System Planning Guide within PacifiCorp’s Engineering Handbook Standards. All Field Engineers use this standard as the foundation for their studies, but they may adapt the approach as needed to account for regional requirements. Engineers also build on this framework using their firsthand understanding of system performance, recent operational events, and any new issues identified during the study”* (p. 17).

Regulatory Proceedings That Address DSP Criteria

Commission staff and stakeholders also can identify planning criteria and standards-related issues in regulatory proceedings and provide recommendations when this information is not part of existing utility filing requirements.

- **Massachusetts.** [National Grid filed for approval](#) of investment proposals to facilitate adoption of distributed generation as part of the Provisional Program established by the Department of Public Utilities. In response to the filing, the Office of [Attorney General recommended improvements](#) to the utility’s engineering approach, including:
 - Increased transparency, requiring the utility to proactively provide information regarding power flow assumptions, methods, and results
 - Development of a data platform to facilitate data sharing on engineering approaches

In its [Order](#), the Commission declined to address these recommendations, indicating that the proposals were more suitable for consideration as part of the [Long-Term System Planning Process](#).

In that ongoing [proceeding](#), the Office of the [Attorney General filed testimony](#) asking the Commission to review the utilities' planning criteria related to investments to accommodate distributed generation (DG). The Attorney General recommended the Commission focus on further analysis to understand *“whether and how N-1 contingency analysis should be applied to DG export, and how flexible hosting capacity tied to the N-0/N-1 rating gap should be incorporated into the Long-Term DG Assessment”* (p. 29).⁷

- **Colorado.** [Commission staff proposed](#) an alternative to the utility’s engineering planning limits in [Xcel Energy’s 2024 DSP proceeding](#). Staff proposed a Risk Uncertainty Framework that would use a sliding scale rather than the utility’s fixed technical planning limit of [75% for feeders and 100% for substation transformers](#). In its [decision](#), the Commission determined that the proposal was not guaranteed to result in significant impacts on capacity project selection.

⁶ The schedule for the proceeding anticipates the Commission considering acceptance of the DSP in November 2026.

⁷ No order has been issued on the Long-Term System Planning Process as of May 13, 2026.

Distribution System Asset Utilization Standard

Some states are going further, initiating a capacity planning standard for asset utilization — for example:

- **Virginia State Corporation Commission (SCC)** approved multi-phase Grid Transformation Plans for Dominion Energy [Virginia under Code § 56-585.1\(A\)\(6\)](#), evaluating specific grid hardening and reliability investment strategies. Virginia's [HB 434](#) (2026) goes further by requiring Dominion Energy and Appalachian Power to file petitions with the SCC establishing metrics to assess grid utilization and comparing performance to optimal asset use, with the SCC establishing utilization improvement timelines. This is an example of a legislative mandate requiring commission review of specific capacity utilization planning parameters.

In summary, while formal approval of certain standards (e.g., granular N-1 contingency thresholds and asset utilization targets) is not widespread at this time, state utility commission engagement to understand engineering and construction standards, reliability metrics, planning methodologies, and investment criteria is well established and growing rapidly across the country.

B. Are there any national entities that issue or develop "planning standards" for utilities?

Several authoritative national bodies develop planning standards directly applicable to electric utility distribution systems, though their scope and enforceability vary considerably.

North American Electric Reliability Corporation

NERC develops and enforces mandatory Reliability Standards for the Bulk Electric System, which generally refers to transmission facilities operating at 100 kV and above. NERC standards address transmission planning ([TPL series](#)), protection ([PRC series](#)), and inverter-based resource performance ([PRC-029-1](#), adopted 2024), among others. The organization's jurisdiction does not extend to distribution systems *per se*; however, distribution-level DERs that affect bulk system reliability are increasingly subject to NERC consideration. NERC standards are developed through an ANSI-accredited process, approved by the Federal Energy Regulatory Commission (FERC).

National Electrical Safety Code

The [NESC \(ANSI C2\)](#), published by IEEE on behalf of ANSI, is the primary national engineering standard governing the design of physical utility distribution infrastructure. The NESC establishes minimum safety standards for the installation and maintenance of electric supply and communication lines and equipment, including distribution conductors. Most states either adopt the NESC by reference or use it as a baseline for their own construction standards. The NESC is updated every five years.

Electric Power Research Institute

EPRI publishes widely referenced technical guidance documents, including a [Distribution Planning Guidebook for the Modern Grid \(2018\)](#), which addresses planning methodologies for systems with high grid-edge resource (GER) penetration. EPRI guidance informs utility planning practices and is frequently cited in commission proceedings as evidence of industry best practice.

U.S. Department of Energy (DOE) and National Laboratories

The DOE and National Laboratories publish technical reports and guidance documents. They include [Grid Architecture: Foundational Report \(2015\)](#), which introduces a holistic approach to analyzing U.S. grids as a means of identifying structural constraints to grid modernization, and the [Modern Distribution Grid Report series](#), which establishes the functional requirements for a modern distribution grid that are needed to enhance reliability, resiliency, and operational efficiency and to integrate and utilize GERS.

C. Is there a widely used definition of "good engineering judgment" as it pertains to the electric system?

The term "good engineering judgment" lacks a single, universally codified definition specific to electric distribution systems. However, several sources provide relevant and well-recognized framing, spanning federal statutes and tariffs, NERC standards, the professional engineering licensure framework, and specific state laws.

Federal Power Act and FERC Definitions

The foundational statutory authority is Section 215 of the Federal Power Act, codified at [16 U.S.C. § 824o](#). Section 215(a)(4) defines "reliability standard" as a requirement to provide for reliable operation of the bulk-power system, and establishes the framework under which NERC develops mandatory standards subject to FERC approval. The statute specifically references "good utility practice" as the operative standard of care that reliability requirements are designed to reflect and codify.

FERC's pro forma Open Access Transmission Tariff (OATT), issued through Order No. [888](#) (1996), defined "Good Utility Practice" in Section 1.14 of the tariff as the operative standard governing transmission operations and interconnections. The definition has been carried forward into all FERC-jurisdictional interconnection agreements, including the Standard [Large Generator Interconnection Agreement](#) and [Small Generator Interconnection Agreement](#). Order No. 888 defines the term.

"Good Utility Practice" – *Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act, section 215(a)(4).*

This definition is notable in two respects. First, it explicitly is not limited to a single optimal practice; it encompasses a range of acceptable approaches. Second, it is time-bound: Judgment is assessed based on what was known at the time of the decision. FERC's [2004 Policy Statement on Reliability Standards \(107 FERC ¶ 61,052\)](#) further clarified that failure to comply with Good Utility Practice could affect cost recovery — directly linking the engineering standard of care to ratemaking frameworks.

"Good engineering judgment" as a standalone phrase appears extensively in federal regulations. The term is generally defined as judgments made consistent with generally accepted scientific and engineering principles and with all available relevant information. This formulation appears in [Title 40 CFR](#) and has been incorporated into various state utility regulatory proceedings.

NERC Reliability Standards and Glossary

NERC's [Reliability Standards and Glossary of Terms](#) define "Good Utility Practice" consistently with the FERC OATT definition. Although NERC's jurisdiction does not extend to distribution systems below the bulk-energy system threshold, this standard of care is widely adopted as the engineering and operational benchmark in state proceedings. NERC standards are developed through an ANSI-accredited process, approved by FERC, and enforceable under Section 215 of the Federal Power Act.

National Society of Professional Engineers Code of Ethics

The NSPE [Code of Ethics](#) establishes that engineers must “*hold paramount the safety, health, and welfare of the public*” and “*perform services only in areas of their competence.*” (Article I.1). The NSPE Code provides a behavioral baseline against which engineering conduct is assessed in licensure proceedings. It is referenced in Minnesota’s continuing education materials for licensed Professional Engineers (PEs).

Minnesota Professional Engineering Licensure Framework

This framework provides a directly applicable, state-specific legal foundation for the concept of “good engineering judgment” as it pertains to utility distribution planning work. The framework is material to Docket 25-142 because utility distribution planning decisions, including the capacity planning standards under review in this proceeding, are made and certified by state-licensed PEs.

- **Governing statute.** The practice of professional engineering in the state is governed by [Minn. Stat. § 326.02](#) et seq. The statute defines the practice as encompassing “*any professional service, such as consultation, investigation, evaluation, planning, design, or responsible supervision of construction or operation, in connection with any public or private utilities ... wherein the public welfare or the safeguarding of life, health, or property is concerned or involved.*” This definition expressly covers utility distribution system planning, design, and operation. [Minn. Stat. § 326.12](#) requires that documents prepared under a PE’s responsible charge bear that PE’s certification, making the licensed engineer personally accountable for the technical judgments embodied in those documents.
- **Rules of Professional Conduct.** The Minnesota Board of Architecture, Engineering, Land Surveying, Landscape Architecture, Geoscience, and Interior Design promulgates Rules of Professional Conduct in [Minn. R. Chapter 1805](#). These rules are binding on all PEs licensed in the state.⁸ The Board administers the PE licensure program and enforces the Rules of Professional Conduct.
 - [Minn. R. 1805.1600, Subpart 1 \(Responsible Charge\)](#) defines the PE in responsible charge as “the person who determines and reviews design criteria, including technical aspects, advises with the client, and has direct supervision of subordinates during the course of the work and, in general, the person whose professional skill and judgment are embodied in the plans, designs, and advice involved in the work.” This definition places the PE’s professional judgment at the center of all engineering deliverables, including distribution planning documents.
 - [Minn. R. 1805.1600, Subpart 2 \(Direct Supervision\)](#) further requires that the supervising PE’s “professional skill and judgment are embodied in the plans, specifications, reports, plats, or other documents required to be certified.”
 - [Minn. R. 1805.0650 \(Competence\)](#) Subpart 1, Standards of competence, requires that “each licensee or certificate holder shall act with reasonable care and competence and shall apply the knowledge and skill that is ordinarily applied by such professionals.” Also, Subpart 3, Qualifications for performing professional services, requires that “A licensee or certificate holder shall perform professional services only when the licensee or certificate holder, together with those whom the licensee or certificate holder may engage as consultants, is qualified by education, training, and experience in the specific technical areas involved.”

⁸ Information on licensure requirements, rules, and disciplinary proceedings is available at mn.gov/aelslagid, and the Board’s statutes and rules are available at revisor.mn.gov.

Implications for the Proposed Planning Standards Review

The PE licensure framework has two important implications for the DOC’s proposed Planning Standards Review.

First, when utility engineers select capacity planning parameters such as a target feeder utilization of 65–70% for N-1 switching reserve, or a worst-case peak load scenario for N-0 rating, those choices are made under the professional signature and certification of a licensed PE, who is personally accountable to the Minnesota Board of Architecture, Engineering, Land Surveying, Landscape Architecture, Geoscience, and Interior Design for the soundness of those judgments. The PE is required by law to exercise independent professional judgment; a review of whether that judgment is reasonable and cost-effective is not an intrusion on engineering discretion, but a public interest check on its outcomes.

Second, the PE standard of care “*consistent with generally accepted scientific and engineering principles and all available relevant information*” ([40 CFR 59.680](#)) is not static. As industry practices evolve (e.g., with dynamic line ratings, probabilistic load forecasting, and GER-aware planning tools), the body of “generally accepted” principles continues to expand. The Commission could assess whether utility-licensed engineers are applying current best practices or relying on conservative legacy standards that may no longer reflect what a competent PE working in today’s environment would reasonably adopt.

For the Commission’s purposes, “good engineering judgment” in the context of distribution capacity planning standards (e.g., N-0 ratings, N-1 switching reserves, equipment utilization thresholds) could be considered to encompass both a floor and a range. The floor could be established by manufacturer equipment ratings, physical conductor limits, and applicable safety codes — non-negotiable engineering constraints. Within these physical limits, the acceptable range of planning parameters (e.g., target feeder utilization of 60–70% vs. 70–80% for N-1 switching capacity; use of worst-case vs. probabilistic peak load forecasts) reflects legitimate engineering judgment that varies across utilities based on system topology, load characteristics, and GER penetration. The Commission could assess whether utilities’ choices within acceptable ranges of planning parameters are justified, cost-effective, and consistent with current industry practice — a reasonable regulatory function that the evidence above suggests is increasingly being pursued in leading jurisdictions.

2. Review of DOC's Proposed Planning Standards

The DOC recommended that the first cycle of a proposed Planning Standards Review Process focus on eight capacity planning standards currently used by Xcel Energy in its Integrated Distribution Plan. This section discusses technical and regulatory considerations for each standard, including its amenability to Commission review, treatment in other jurisdictions and national research, and — where alternative methodologies exist — their implications.

A. CAPACITY FORECASTING AND ACCURACY

Summary Assessment: A viable topic for consideration

Forecast accuracy encompasses two interrelated issues: (1) predicting future gross load growth (load forecasting), and (2) netting out the impact of behind-the-meter DG, primarily solar PV and flexible loads, to determine the net peak demand for distribution infrastructure. The resulting “net load” forecasts at the feeder and substation level are the operative planning inputs.

Utility interviews by the National Laboratory of the Rockies (NLR) in 2022 confirmed that most utilities continued to use deterministic forecast methods — a single expected-case trajectory based on historical

trends — rather than probabilistic or scenario-based approaches,⁹ despite the increasing volatility introduced by GER adoption (Keen et al., 2022).

Proposed Standard B (N-0 uncertainty margin — next subsection) concerns only the accuracy of the long-run growth forecast itself, not the operating margin applied to it. Both must be addressed, but they are methodologically distinct. Forecasting accuracy is a data- and model-quality question, while the uncertainty margin is a risk-management decision.

Regulatory Considerations

The Commission could require a utility to report historical forecast accuracy, specifically the mean absolute percentage error of its feeder and substation-level peak load forecasts relative to actual outcomes. This is a prerequisite for evaluating whether the uncertainty margins a utility embeds in its N-0 planning standard (Topic B below) are appropriately calibrated or systematically over-conservative.

For example, New York [PSC staff guidance](#) for DSIPs requires utilities to “Describe the levels of accuracy achieved in the substation-level forecasts produced to date for load and supply” (p. 14). Staff also provides guidance for utilities to “Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency measures” (p. 14). Consolidated Edison's [2023 DSIP filing](#) included the following information on forecast accuracy: “The system peak forecast has an average 5-year error rate of approximately 2.4 percent and the network independent peak forecast for individual networks and radial systems has an average 5-year error rate of 8.6 percent. These variances from forecast are high and reflect the error caused by the COVID-19 Pandemic. These values were 1.0 percent and 2.8 percent respectively in the last DSIP filing. The Company expects these to variances to reduce in 2023 and beyond” (p. 42).¹⁰

B. N-0 FORECAST UNCERTAINTY MARGIN AND THE USE OF AMI OR OTHER ACTUAL DATA

Summary Assessment: A viable topic for consideration

The critical planning question is what load level the utility uses to trigger a capacity upgrade, rather than the physical rating ceiling.

The Uncertainty Margin Problem

Current industry practice is to take a worst-case historical peak load — typically from the hottest or coldest year in a 3–10-year historical window, depending on whether the system is summer- or winter-peaking; project it forward at an assumed annual growth rate; and set a flat-line capacity threshold for all 8,760 hours of the year at that value. When projected load exceeds a fixed percentage of the equipment’s normal rating (commonly 80-90% for feeders, 85-95% for substation transformers), a capacity upgrade is triggered.

This approach has two related problems that the Commission could directly scrutinize:

- **Over-conservatism from static worst-case assumptions:** The actual peak load on any feeder occurs for only a handful of hours per year. Setting a flat capacity limit based on an extreme-year worst-case scenario effectively leaves headroom within the physical equipment rating unused for

⁹ Probabilistic analysis explicitly models the full range of outcomes, not just the middle of the distribution. Scenario analysis assesses the potential impact of various plausible future events.

¹⁰ While the Oregon PUC did not establish a specific standard for forecasting accuracy, PGE’s [2024 DSP filing](#) provides another example of the type of information that can be provided: “Overall, 2023 incremental forecasted solar adoption at the system-level was 18 percent lower than actuals, which fell within the low case sensitivity range from our AdopDER outputs. At the locational level, the substation level forecast to actuals difference ranged from -550 kW to +875 kW, with an average of +64 kW over-forecasted per substation” (p. 263).

the vast majority of operating hours. This translates into capital expenditures for capacity upgrades that are earlier than necessary.¹¹

- **Increasing inapplicability with GER growth:** Rooftop solar, battery storage, and controllable EV charging are changing historical peak load patterns. A static worst-case historical approach will increasingly miscalibrate the timing and magnitude of capacity needs.

The Role of AMI Data

AMI fundamentally changes what is possible. Utilities can observe actual hourly (or 15-minute) loads at the customer level, aggregate this information at the feeder and substation levels, and use realized load distributions rather than worst-case historical peaks for planning. This enables two advances:

- **Actual peak characterization:** Rather than using a worst-case weather-normalized peak for the year, the utility can characterize the probability distribution of peak loads at each planning node — including the observed frequency, duration, and temperature-sensitivity of peak events — to calibrate a statistically defensible uncertainty margin.
- **Dynamic or flexible rating methods:** Drawing on the dynamic thermal rating literature developed for transmission (IEEE Std. 738; CIGRE Technical Brochures 601 and 969), similar approaches can be applied to distribution-level conductors, using measured ambient temperature, solar radiation, and wind conditions along a line corridor to calculate time-varying thermal ratings rather than fixed static ratings. Studies consistently show that static line ratings are conservative relative to actual operating conditions for the majority of hours, with dynamic ratings often 15-30% higher than static ratings during off-peak periods.

The NLR *Distribution Capacity Expansion Planning* report (2022) notes that most utilities interviewed “refer to [load and GER forecasting] as ‘deterministic’ because the output is fully determined by the initial value of weather-normalized existing peak load combined with exogenous load and DER growth values” (p. 15). The study explicitly identifies probabilistic and scenario-based planning as key areas where current utility practice falls short of what AMI data enables.

Regulatory Considerations

This is the type of planning standard where the Commission can add significant value. The question is whether the utility’s chosen uncertainty margin, embedded in a static worst-case loading standard applied uniformly across 8,760 hours and all planning nodes, is the most cost-effective approach available given current data and methodological capabilities. For example, the Commission could require a utility to:

- Disclose its current N-0 loading thresholds by equipment type (feeders, substation transformers, line sections) and the basis for those thresholds
- Report what percentage of feeder and substation loading events actually approach or exceed those thresholds in a given year, using AMI data
- Demonstrate whether its uncertainty margin has been calibrated against actual forecast error distributions (linking directly to proposed Standard A), or whether it is a legacy engineering convention
- Evaluate whether a flexible or probabilistic loading standard informed by AMI-derived actual load distributions could achieve the same reliability outcomes at lower cost, deferring capacity investments in nodes where the static worst-case criterion generates false positives

¹¹ In some cases, upgrades might be avoided if future conditions are different than expected.

C. N-1 PROBABILITY OF COINCIDENT PEAK LOAD AND N-1 CONTINGENCIES

Summary Assessment: The proposed framing conflates two distinct planning problems. The Commission could redirect attention to underlying questions about N-1 switching reserve.

Why the Framing Is Challenging

The DOC's proposal to develop a probabilistic standard for N-1 contingencies coincident with peak load is technically well-intentioned but practically infeasible in its literal formulation.

N-1 contingencies — the failure of a single circuit element such as a transformer, line section, or switch — are random events distributed across thousands of planning nodes. Coincident peak is itself a stochastic variable for any given feeder and increasingly so as GER penetration grows. Overlaying two independent stochastic processes (contingency timing and peak load magnitude) across each feeder segment, feeder, and substation to derive a systemwide probabilistic target is computationally and analytically complex to the extent that it would be unlikely to yield actionable standards within a reasonable planning cycle.

More fundamentally, the practical objective embedded in this proposed standard is not probabilistic contingency analysis; it is determining the appropriate level of switching capacity reserve the utility could maintain to restore customers in unaffected segments following a contingency. That is a well-defined and directly reviewable question.

The Actual Planning Standard: N-1 Switching Reserve

In the context of distribution systems, N-1 switching reserve refers to the available capacity on adjacent feeders, or the feeder's alternate switching paths, to pick up load from an affected segment during a fault-induced outage. A utility with a 60-65% normal loading standard on its feeders preserves 35-40% headroom that can, in principle, absorb transferred load from a neighboring feeder during a contingency, thereby limiting the duration and extent of customer interruptions. Higher normal loading standards consume this switching reserve, reducing restoration flexibility.

N-1 switching reserve loading targets vary considerably across utilities and depend on system topology, feeder tie configurations, substation transformer switching arrangements, and load density. A single national standard does not exist. Utilities' historical targets reflect designs of their specific system.

Regulatory Considerations

The Commission could redirect consideration of this standard toward questions that are directly answerable:

- **What is the utility's N-1 switching reserve target by equipment class, and what is the engineering and historical justification for that target?** The Commission could require disclosure of the utility's normal loading thresholds, the proportion of feeders and substations currently operating above them, and whether the utility has reviewed the targets in light of topology changes from grid automation and GER integration.
- **Can switching reserve be evaluated in conjunction with outage cost analysis using the LBNL ICE Calculator?** Since normal reserve margins are related to reliability, the cost-effectiveness of the margins can be calculated in a trade-off analysis against the value of the GER or load growth that otherwise is constrained. The [ICE Calculator 2.0](#) developed by LBNL can be used to assess the reliability value in this type of trade-off analysis.

D. N-1 SCREENING BASED ON COST-EFFECTIVENESS

Summary Assessment: The framing could be revised from “screening” to benefit-cost analysis of N-1 switching investments, a productive and tractable area for Commission review.

"Screening" implies a binary pass/fail threshold applied to individual projects. That is, a project either passes the N-1 criterion (and proceeds) or fails it (and is re-scoped or deferred). A more appropriate framing is a benefit-cost analysis of investments to improve N-1 switching capability, assessed against the reliability improvements and incremental avoided customer-interruption costs they would produce. For example, Ameren Illinois' [2026 Multi-Year Integrated Grid Plan filing](#) includes N-1 switching capability investments, referred to as “*Redundant Capacity Expansion (N-1)*,” as part of its cost-effectiveness evaluation framework. To evaluate the cost-effectiveness of these investments, the utility uses a least-cost, best-fit approach, supplemented by a benefit-cost ratio from Copperleaf, a software tool for infrastructure investment planning.

Regulatory Considerations

There are diminishing returns associated with incremental improvements in reliability. For example, in the District of Columbia, the utility has continued to target a 2% annual improvement in reliability for about a decade. At this point, it is unlikely that there is substantive value in pursuing the next level of reliability, given that the utility is already performing at 1st quartile levels nationally.

E. EQUIPMENT RATINGS DURING N-1 EMERGENCIES

Summary Assessment: Physical limits are non-negotiable. Commission review could focus on protocols and documentation for emergency rating use.

Equipment emergency ratings specify the short-duration, higher-current capacity available during contingency conditions. These ratings are determined by manufacturer specifications based on the thermal properties of the conductor or transformer materials. A copper or aluminum conductor of a given cross-section will anneal and lose mechanical strength if operated above its design temperature, regardless of what planning standard a utility or Commission chooses to apply. These physical constraints are not fertile ground for regulatory review.

Regulatory Considerations

The Commission’s interest in this standard is not in the physical ratings themselves, but in the following related operational and planning questions:

- **Emergency rating duration protocols:** How long does the utility operate equipment at its emergency rating following an N-1 contingency before initiating load relief actions (e.g., load transfers, switching, demand response dispatch)? Are these protocols documented and consistently applied? Is the duration consistent with equipment manufacturer guidance?
- **Emergency rating calibration against AMI data:** Emergency ratings are typically specified by equipment type (e.g., a given kVA transformer or conductor size) for worst-case ambient conditions (e.g., 40°C ambient temperature, full solar exposure, calm wind). Under actual conditions in most hours, thermal headroom beyond the emergency rating may exist. Dynamic thermal rating approaches applied to distribution-level conductors using sensor-measured or modeled ambient data could enable more precise management of the boundary between normal and emergency ratings during contingency recovery, potentially reducing the duration and scope of load interruptions.
- **Emergency rating documentation and standardization:** Are the utility’s emergency ratings uniformly applied across their system, or do they vary by vintage and type of installed equipment? Is the utility tracking the proportion of its installed base that has been field-rated, or simply using

the manufacturer default ratings? Aging infrastructure may have de-rated effective capacity relative to nameplate ratings.

The Commission could require a utility to disclose its policies and protocols for using emergency ratings, document the basis for emergency rating values used in planning models, and confirm whether those values reflect actual installed equipment ratings or conservative defaults.

F. SIZING NEW ASSETS FOR FUTURE LOAD GROWTH

Summary Assessment: Equipment standardization practices constrain sizing flexibility. Commission review could focus on the load growth forecast that drives equipment sizing decisions, rather than the sizing convention itself.

Distribution equipment comes in discrete standard sizes. Distribution transformers are manufactured in standard kVA ratings (e.g., 25, 37.5, 50, 75, 100, 167, 333, and 500 kVA for single-phase padmounts; 500, 750, 1000, 1500, 2000, 2500, and above for three-phase units). Conductors are manufactured in standard American Wire Gauge and kilo-circular mil sizes. When a load forecast indicates that a substation transformer will be loaded to 80% of its rating within five years, the utility selects the next standard size up; it cannot procure a transformer sized exactly to the load forecast.

Why Exact Sizing Is Not Feasible

Utilities standardize on a limited set of equipment sizes for sound operational and economic reasons:

- *Inventory management:* Maintaining spare equipment in a limited number of standard sizes reduces warehousing costs and ensures that storm restoration crews have compatible replacement units readily available.
- *Construction efficiency:* Standardized designs allow crews to work using familiar plans, reducing design time and installation error.
- *Safety in emergency operations:* During large-scale storm restoration, crews pulling equipment from central warehouses must be certain that the replacement units are electrically and mechanically compatible with what they are replacing. Non-standard sizes risk creating capacity bottlenecks or protection mismatches if incorrectly substituted.

Regulatory Considerations

The more productive regulatory question is what load forecast and loading threshold trigger the utility's decision to upsize. An over-conservative N-0 uncertainty margin (as discussed in the section on proposed Standard B) will trigger premature upsizing decisions, locking in an oversized (next standard) unit earlier than necessary. The capital and rate implications of this over-conservatism compound. A transformer that is upsized from 500 kVA to 750 kVA five years earlier than an optimized forecast would indicate is costly for ratepayers.

The Commission's review of proposed Standard F could be structured as a review of the load growth forecast and the uncertainty margin that drive sizing decisions (linking to proposed Standards A and B), rather than a direct review of equipment sizing conventions. Improved forecasting and margin standards will improve utility sizing decisions.

Analysis of investment triggers, and decisions to upsize, also are related to proactive investment frameworks to enable load growth, for which the Commission has ongoing efforts. The review of Standard F can be implemented in coordination with the Proactive Grid Upgrade Workgroup and Docket [24-318](#).

G. CAPACITY RISK FRAMEWORK

Summary Assessment: This is the most conceptually open-ended of the eight proposed standards. It maps to portfolio-level risk management under uncertainty, particularly related to load growth and GER adoption, a growing area of state regulatory interest.

The term “Capacity Risk Framework” does not appear as a defined term in national distribution planning literature or in state regulatory requirements reviewed by LBNL. Its meaning in the context of the DOC’s recommendation requires clarification, but it most likely refers to how the utility assesses and manages the risk that its distribution system will be inadequate to serve load under adverse but plausible scenarios (i.e., the reserve margin for distribution system-level planning).

Two Possible Interpretations

- (1) **Scenario-based planning reserve.** In transmission and bulk power planning, capacity risk frameworks typically involve probabilistic or scenario-based analysis of resource adequacy — for example, using loss-of-load probability and expected unserved energy metrics. Applied to distribution, this would mean analyzing the probability that, across a range of load growth and GER adoption scenarios, one or more feeders or substations will exceed capacity constraints without additional utility investment. This is precisely the probabilistic or scenario-based planning approach that LBNL has described in several publications and is being incorporated in state regulations or guidance across the country.
- (2) **Investment risk management under uncertainty.** Alternatively, a Capacity Risk Framework could address how a utility decides when to commit capital to capacity upgrades, given uncertainty about timelines for load growth and GER adoption. Under high GER adoption, investments in traditional capacity (transformers, conductors) may be stranded if demand growth is offset by customer-sited solar and storage. Conversely, delaying investment risks reliability failures if load grows faster than forecast. Frameworks for managing this optionality, such as staged investment, modular capacity additions, or GER-first strategies, are increasingly discussed in distribution planning contexts.

Regulatory Considerations

After clarifying the meaning of the DOC’s proposed Capacity Risk Framework in the context of distribution planning — (1) or (2) above, or both — the Commission could require the utility to:

- Describe any existing mechanisms the utility uses to manage capacity investment risk under load growth and GER adoption uncertainty, and/or
- If related to planning reserve margin for distribution, characterize the utility’s capacity risk probabilistically and calibrate the uncertainty margin to a defined risk tolerance, using actual AMI-derived load distributions rather than static worst-case scenarios, instead of applying a conservative engineering convention without explicit risk quantification.¹²

H. PROJECT PRIORITIZATION

Summary Assessment: This is the most tractable topic for Commission review, a mature and well-documented area.

Project prioritization — how a utility ranks and sequences its distribution capital expenditures across the categories of reliability, capacity, asset health, grid modernization, GER integration, and operations & maintenance — is the operational output of the planning process where all other standards converge. It also is where the Commission and ratepayers are most directly affected. The sequence and prioritization

¹² The flexible distribution line rating approach described in connection with proposed Standard B is directly relevant.

of projects determine the timing of rate impacts and the distribution of reliability benefits across the system.

The LBNL Framework

The LBNL report, [*Economic Evaluation of Modernization Expenditures for Electric Utility Distribution Systems: A Guide for Utility Regulators*](#) (De Martini, Schwartz, and Ball, 2025), is the most directly applicable national reference. The Commission could use this resource to guide improved utility evaluation of project prioritization.

Regulatory Considerations

At a minimum, the Commission could require a utility to disclose:

- *The objectives and weighting criteria used in its project prioritization model, and the regulatory or utility policy basis for those weightings.* For example, [regulated utilities in Oregon are required](#) to provide information on the criteria and methods they use to prioritize investments and expenditures, including how they contribute to state and Commission objectives (e.g., reliability, safety and security, integration of GERs). [PGE's 2024 DSP](#) includes information on prioritization criteria (e.g., safety concerns, transformer and feeder utilization index, transformers and feeders exceeding criteria), maximum score attributable to each criterion, and criteria weights used to determine prioritization.¹³
- *The cost-effectiveness screening methodology applied to individual projects, depending on project type and cost, including the utility's evaluation of non-wires alternatives to traditional capacity investments.*
- *The benefit metrics and benefit quantification methods used, including whether the utility includes avoided customer outage costs and how the utility estimates them.* For example, in Illinois, regulated utilities are required to “provide for the analysis of the cost-effectiveness of proposed system investments, [...]” [220 ILCS 5/16-105.17, \(d\), \(7\)](#). ComEd's [2026 Multi-Year Integrated Grid Plan](#) describes the utility's cost-effectiveness methodologies, including the type of analysis conducted (i.e., Lowest Reasonable Cost, Benefit-Cost Analysis) and type of applicable expenditures (e.g., grid reliability, operational efficiency improvements, enhanced customer choice). The plan provides the results of the utility's cost-effectiveness analysis for each spending category and discusses the associated quantitative and qualitative benefits. ComEd cites recent improvements for considering outage costs, including integrating an assessment of resiliency benefits using LBNL's [Power Outage Economics Tool](#).
- *Whether the prioritization methodology has been reviewed or updated to reflect current best practices for integrated distribution system planning, including the LBNL guide for regulators.*
- *A project-level disclosure for all planned investments above a defined cost threshold, including the planning need, the alternatives evaluated, the selected solution, and the cost-effectiveness analysis supporting that selection.*

3. Alternative to forming a working group to assess Xcel Energy's engineering standards and decision-making practices

¹³ While not required by the Michigan PSC, [DTE's 2023 DSP](#) includes information on its Global Prioritization Model, developed to support investment selection. The utility provides information on the dimensions, drivers, and weights included in the model, as well as how the model has evolved in response to Commission and stakeholder feedback (see p. 168). The utility provided additional information in a [technical conference](#) (slide 77).

The Commission may wish to consider whether a targeted, one-time independent engineering audit could achieve the same near-term objectives with substantially less administrative burden. Such an audit would critically assess Xcel Energy's planning standards, decision-making practices, and their relationship to capital investment decisions. Such audits produce a prioritized set of findings identifying:

- Standards (or criteria) and practices with the greatest influence on capital spending
- Areas where actual practice diverges from stated standards or business practices
- Comparison to industry best engineering practices
- Modifications that appear technically feasible and cost-effective

These findings could inform a focused Commission directive in the subsequent IDP cycle.

Such an approach offers several benefits: First, an independent utility auditing firm would manage the process and submit findings directly to the Commission, avoiding the staff burden of facilitating an extensive stakeholder process. Second, the audit relies on professional engineering expertise to evaluate highly technical planning standards and internal utility decision-making processes. Third, the approach maintains engineering and business accountability with Xcel. The [District of Columbia](#), [Maine](#), and other states have used similar audits to evaluate utility planning criteria and decision-making processes regarding T&D expenditures.

4. Best practices for assessing a utility's forecasted vs. actual distribution system spending outside of a rate case

The Commission could require annual reporting on the variance between the utility's IDP forecast and actual capital and O&M expenditures, including an explanation of material deviations. A useful model is the annual reporting requirement used by the Public Service Commission of the District of Columbia. The Commission requires Pepco to submit an [annual informational filing](#) to identify and explain variances between planned and actual capital and O&M spending. This includes identifying key drivers of material deviations and providing updated projections for the next calendar year.

Other states are incorporating similar requirements as part of ongoing annual reporting under DSP regulations. For example, the [Maryland Electric System Planning regulations](#) require the following.

B. Annual Electric System Plan Update.

(1) Electric companies shall include the following annual electric system plan updates:

(a) A narrative describing the existing planning and forecasting processes, current capabilities that exist, and plans for potential future improvements;

(b) Relevant planning criteria utilized to identify system constraints;

(c) Description of any new market or policy conditions that are impacting the planning environment and how they plan to incorporate them into future planning;

(d) Description of any updates to system constraints or constraint solutions that may have changed from the previous year, including, but not limited to, updates on progress regarding projects and programs that have changed from the previous year and rationale for the change;

(e) A report using a common framework for electric company reporting as directed by the Commission, with information regarding the current status of projects designed to promote State policy goals identified in Public Utilities Article §7-802, Annotated Code of Maryland, including information on planning processes and implementation that promote these goals; and

(f) Electric system plan targets and planning metrics pursuant to Regulation .05 of this chapter.

(2) Electric companies shall file an annual electric system plan update no less than 75 days prior to the annual technical conference.

(3) In the year an electric company files a preliminary electric system plan, an annual electric system plan update is not required

In both the District of Columbia and Maryland, the utilities' filings are subject to stakeholder review, including the opportunity to submit data requests. In addition, the commissions host annual technical conferences where utilities provide updates on distribution planning criteria, methods and tools, and cost forecasts.

Three complementary requirements could be incorporated into Minnesota's IDP process:

- *Annual variance report:* Require Xcel to file an annual report in the IDP docket comparing planned and actual capital expenditures by major investment category, explaining deviations exceeding 10 percent and identifying projects that were deferred, descope, or eliminated.
- *Three-year retrospective in each IDP:* Require Xcel to include a structured comparison of planned versus actual expenditures and project completions from the prior cycle, including discussion of any implications for planning standards associated with material over- or under-execution.
- *Annual IDP technical conference:* Require Xcel to present its Annual IDP Report in years between IDP filings and solicit feedback from stakeholders to inform ongoing planning and the next IDP.

These requirements create a durable accountability record and provide a factual foundation for meaningful evaluation of planning standards and criteria, as well as expenditure outcomes.

References and Additional Resources

LBNL

- [Economic Evaluation of Modernization Expenditures for Electric Utility Distribution Systems: A Guide for Utility Regulators](#) — De Martini, Schwartz, and Ball (2025)
- [State Requirements for Electric Distribution System Planning](#), Schwartz, Mims Frick, Murphy, Pereira, Relf, Shipley, and Schellenberg (2025)
- [Bridging the Gap on Data and Analysis for Distribution System Planning](#), Murphy, Schwartz, Pereira, and Davis (2025)
- [Integrating Resilience Planning in Distribution System Planning](#), Collins, Millet Dias, De Martini, Schwartz (forthcoming; external peer review draft available on request)
- [ICE Calculator 2.0 — Interruption Cost Estimate](#), LBNL and Resource Innovations (released July 2025); Phase 1 Final Report: emp.lbl.gov/publications/ice-calculator-20-final-report-phase
- Power Outage Economics Tool: A Prototype for the Commonwealth Edison Service Territory, Larsen et al. (2024)
- [State Distribution Planning Practices online catalog](#) (next update expected late May 2026)
- [Integrated Distribution System Planning website](#)

NLR

- [Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support](#), Keen et al. (NLR/TP-6A40-83892, 2022)

PNNL

- [Grid Architecture: Foundational Report \(2015\)](#)

DOE

- [Modern Distribution Grid report series](#) (2017-2020)

Industry

- EPRI, [Distribution Planning Guidebook for the Modern Grid \(2018\)](#)
- [IEEE Std. 738, Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors](#) (thermal rating standard used for both static and dynamic line rating calculations)
- CIGRE [Technical Brochure 601, Guide for Thermal Rating Calculations of Overhead Lines](#) (2014); [TB 969 - Forecasting Dynamic Thermal Line Ratings](#) (2015)