MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	Tuesday July 2, 2024	Agenda Item **5
Company	Northern States Power Company d/b/a Xcel Energy	
Docket No.	**E002/M-23-452**	
	In the Matter of Xcel Energy's 2023 Integrated Distribution Plan	

Issues

1. Should the Commission accept or reject Xcel Energy's 2023 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?

Staff			
	Hanna Terwilliger	hanna.terwilliger@state.m.us	651-201-2243
	Derek Duran	derek.duran@state.mn.us	651-201-2206

✓ **Relevant Documents**	**Date**
Xcel Energy, Report – 2023 Integrated Distribution Plan Parts 1-3	November 1, 2023
PUC, Ex Parte Communication	February 21, 2024
Initial Comments	
Clean Energy Groups	March 1, 2024
Grid Equity Commenters	March 1, 2024
Fresh Energy	March 1, 2024
City of Minneapolis	March 1, 2024
Department of Commerce	March 4, 2024
Reply Comments	

Relevant Documents	Date
Xcel Energy	March 22, 2024
Clean Energy Economy MN	April 12, 2024
City of Minneapolis	April 12, 2024
Clean Energy Groups	April 12, 2024
Grid Equity Commenters	April 12, 2024
Fresh Energy	April 12, 2024
Department of Commerce	April 12, 2024
Office of the Attorney General - Letter	April 12, 2024
Fresh Energy - Letter	April 30, 2024
Xcel Energy – Information Request, MPUC IR No. 1	May 17, 2024

Table of Contents

1. Acronyms

ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
APT	Advanced Planning Tool
Area EPS	Area Electric Power System
ARR Split	Avoided Revenue Requirement Split
BCA/CBA	Benefit Cost Analysis/Cost Benefit Analysis
BESS	Battery Energy Storage System
BIPOC	Black, Indigenous, and People of Color
BTM	Behind the Meter
CAIDI	Customer Average Interruption Duration Index

CEEM	Clean Energy Economy Minnesota
CEG	Clean Energy Groups
CEJST	Climate and Economic Justice Screening Tool
CELI	Customers Experiencing Lengthy Interruptions
CEMI	Customers Experiencing Multiple Interruptions
CEUD	Customer Energy Usage Data
CIAC	Contribution In Aid of Construction
CIP	Conservation Improvement Program
CSG	Community Solar Garden
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DER	Distributed Energy Resource
DF	Dependability Factor
DF_{PV}	Dependability Factor of Photovoltaics
DG	Distributed Generation
DGWG	Distributed Generation Working Group
DHC	Dynamic Hosting Capacity
DI	Distributed Intelligence
DML	Daytime Minimum Load
DOE	Department of Energy
DR	Demand Response
DRMS	Demand Response Management Systems
DSM	Demand Side Management
ECO	Energy Conservation and Optimization
EE	Energy Efficiency
EJ	Environmental Justice
EPA	Environmental Protection Agency
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FAN	Field Area Network
FI	Flexible Interconnection
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front of the Meter
GEC	Grid Equity Commenters
GIS	Geographical Information System
HAN	Home Area Network
HCA	Hosting Capacity Analysis
IDP	Integrated Distribution Plan
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IT	Information Technology
IVVO	Integrated Volt-Var Optimization
i2X	Interconnection e-Xchange

kV	Kilo Volts
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
MN DIP	Minnesota Distributed Interconnection Procedures
MN DIA	Minnesota Distributed Interconnection Agreement
MPCA	Minnesota Pollution Control Agency
MSA	Minnesota Solar Advocates
MnSEIA	Minnesota Solar Energy Industries Association
MV	Mega Volts
MVA	Mega Volt Amp
MW	Mega Watts
NESC	National Electrical Safety Code
NPV	Net Present Value
NSPM	Northern States Power Company-Minnesota
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OAG	Office of the Attorney General
OMS	Outage Management System
PNL	Planned Net Load/Planned Net Loading
PCT	Participant Cost Test
PIM	Performance Incentive Mechanism
PSCo	Public Service Company of Colorado (Xcel)
PUC	Public Utilities Commission
RFI	Request for Information
RFP	Request for Proposal
RIM	Ratepayer Impact Measure
RMP	Resilient Minneapolis Project
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAIPE	Small Area Income and Poverty Estimates
SCADA	Supervisory Control and Data Acquisition
SCT	Societal Cost Test
SQSR	Service Quality, Safety, and Reliability
TCR	Transmission Cost Recovery
TEP	Transportation Electrification Plan
The Company	Xcel Energy
TPS	Technical Planning Standard
TMY	Typical Meteorological Year
TOD	Time of Day
TOU	Time of Use
V2G	Vehicle to Grid
VOS	Value of Solar
WACC	Weighted Average Cost of Capital

2. Statement of the Issues

1. Should the Commission accept or reject Xcel Energy's 2023 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?

3. Background

On November 1, 2023, Xcel Energy (Xcel or the Company) filed the Company's 2023 Integrated Distribution Plan (IDP).

On March 1, 2024, the following organizations filed initial comments:

- City of Minneapolis
- Grid Equity Commenters (GEC)[1]
- Fresh Energy
- Department of Commerce (Department)

On March 22, 2024, Xcel Energy filed reply comments.

On April 12, 2024, the following organizations filed reply comments:

- City of Minneapolis
- Grid Equity Commenters (GEC)
- Fresh Energy
- Office of the Attorney General
- Department
- Clean Energy Groups (CEG)[2]
- Clean Energy Economy Minnesota (CEEM)

The purpose of the Commission's IDP filing requirements is to facilitate a utility's IDP that will:

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

[1] Cooperative Energy Futures, Environmental Law & Policy Center (ELPC), Sierra Club, and Vote Solar
[2] Fresh Energy, Sierra Club, Union of Concerned Scientists, Plug In America

- 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.[3]

Minn. Stat. § 216B.2425 states, in part, that a utility under a multiyear rate plan approved by the Commission shall identify investments that it considers necessary to modernize the distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response and other innovative technologies. By June 1, the Commission then shall certify, certify as modified or deny certification of distribution projects proposed. Xcel did not propose any projects for certification in this IDP

The Commission's filing requirements cover six main topics:

- Baseline Distribution System Data and Financial Data
- Hosting Capacity and Interconnection Requirements
- Distributed Energy Resource Scenarios Analysis
- Long-Term Distribution System Modernization and Infrastructure Plan
- Non-Wires Alternatives Analysis
- Transportation Electrification Plan (TEP)

The Commission approved Xcel Energy's TEP with modifications in its May 9, 2024 Order in the present docket.

4. Staff Introduction

Since Xcel Energy's last IDP there has been a marked shift in the energy policy landscape for the distribution system. New state policies changes encouraging more distributed solar, federal legislation offering rebates to accelerate beneficial electrification, and accelerating adoption of electric vehicles, coupled with aging grid infrastructure mean the distribution system is poised for transformation. Xcel has presented a detailed IDP that outlines the Company's vision for the distribution grid of the future, and indicates it is starting to actualize the capabilities of early grid mod investments approved by the Commission. While there are differing opinions on the Company's chosen path and reasonable requests for more information, Staff believes that the Xcel's 2023 IDP presents a clear picture and excellent starting point to evaluate the distribution system and how it will need to evolve in the coming years.

Staff identified the following themes to keep in mind when reviewing Xcel Energy's IDP:

- Evaluating planned budget forecasts critically.
- Ensuring grid modernization investments, both existing and future, are used to their full capabilities.
- Using existing and future DERs for their full stack of benefits.

[3] Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy Issued August 30, 2018, Docket No. E-002/CI-18-251.

- Developing a concise yet comprehensive set of data to evaluate distribution system performance and spending.
- Ensuring investments and benefits for grid upgrades, DERs, and electrification are distributed in a just and equitable way.
- Determining whether the grid is ready for increased DERs and electrification.

5. Summary of IDP

Xcel's 2023 IDP outlines the Company's strategic priorities for its distribution system investments and plans over the coming years. These include:

- Preparing for New and Increased Load
- Enabling the Clean Energy Transition
- Maintaining and Enhancing Reliability and Resilience
- Modernizing the Grid

In this IDP, Xcel seeks Commission and stakeholder guidance on its overall plans and direction, especially as it relates to the Company's future Distributed Energy Resource (DER) investments.

A. IDP Acceptance

Fresh Energy recommended acceptance of Xcel's 2023 IDP and believed that the Company had addressed the Commission's filing requirements and prior Order points.[4]

The GEC recommended acceptance of Xcel's 2023 if the Commission requires additional filings and actions.[5]

Minneapolis recommended accepting the 2023 IDP with modifications.[6]

The Department indicated that for the most part Xcel had complied with the IDP filing requirements, Commission Orders, and statutes, except for 3.D.2, which is discussed in the Grid Modernization Initiatives section. Therefore, the Department recommended accepting Xcel's IDP once the Company files an updated Attachment C.

CEEM did not recommend acceptance of Xcel's 2023 IDP, stating first the Company needed to provide additional information and transparency.[7]

Staff believes 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. As explained in the Joint Briefing Papers, the Commission does not modify IDPs, therefore Staff recommends accepting Xcel's 2023 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 upon filing an amended Attachment C

---

[4] Fresh Energy, Initial Comments, March 1, 2024, p. 4
[5] GEC, Initial Comments, March 1, 2024, p. 21
[6] Minneapolis, Initial Comments, March 1, 2024, p. 1
[7] CEEM, Reply Comments, April 12, 2024, p. 1

- **Decision Option 3** does not accept the Company's IDP

B. Distribution System Statistics

Table 1 summarizes distribution statistics from Appendix A4 of Xcel's IDP.[8]

Table 1: Distribution System Statistics

Bulk System Peak for 2022	6,973 MW (5pm, July 20, 2022)	Minnesota Service Area
Distribution Substation Capacity	13,505 MVA	Minnesota Service Area
Total Overhead Distribution Wire	13,263 miles	NSPM
Total Underground Distribution Wire	10,496 miles	NSPM
Total Distribution Premises	1,341,847	Minnesota Service Area

For the purposes of IDP, the Commission defines DERs as:

> *Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.*

Table 2 contains a snapshot of the status of DERs in Xcel's service territory as of March 2023.

Table 2: Minnesota Distribution Connected DERs[9]

	Completed Projects		Queued Project	
	MW	# Projects	MW	# Projects
Rooftop Solar	162_{dc}	10,283	93_{dc}	3,939
RDF Projects	35_{dc}	25	1_{dc}	1
Wind	9_{dc}	58	$<1_{dc}$	5
Storage/Batteries	$<1_{dc}$	25	$<1_{dc}$	48
Community Solar	864_{ac}	463	304_{ac}	330
Grid Scale (Aurora)	100_{ac}	16	0_{ac}	0
Energy Efficiency[10]	2,433	n/a	n/a	n/a
Demand Response	820	421,000	n/a	n/a
Electric Vehicles	n/a	34,532	n/a	n/a

Staff notes that Xcel continues to report some existing DERs in MW_{dc} despite commitments at prior IDP hearings to report in MW_{ac}. Staff recommends adopting **Decision Option 4** to require Xcel to report all DERs and DER forecasts in MW_{ac}.

C. Load and DER Forecast

[8] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A4, November 1, 2023, p. 1-8 (PDF p. 173-180)
[9] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 30-31 (PDF p. 48-49)
[10] Cumulative since 2005

The 2023 IDP marks Xcel Energy's inaugural use of its Advanced Planning Tool (APT), LoadSEER, that was certified in the Company's 2019 IDP. According to the Company, it uses "LoadSEER for medium- to long-range load forecasting of distribution feeders and substation transformers. The LoadSEER system is the historical peak system of record for those distribution elements. LoadSEER also analyzes historical supervisory control and data acquisition (SCADA), customer billing, and weather data to determine the typical annual hourly loading on each feeder and substation transformer. The tool combines this typical loading with a simulation of load and DER growth to develop an annual load forecast up to 30 years into the future."[11]

Xcel Energy broke down its load forecasting between forecasting impacted by DERs and forecasting as conducted by LoadSEER. The Company's load forecast focuses on demand, not energy, to ensure the Company can serve peak loads. Peak load is defined as the largest power demand at a given point during one year.[12] To calculate peak load, the Company generated a forecast and ran a variety of scenarios through that forecast to accommodate planning efforts and real time load changes. Such scenarios account for:

- Historical load growth;
- Weather history;
- Customer planned load additions;
- Circuit reconfigurations;
- New sources of demand;
- DER applications; and
- Planned development or redevelopment.[13]

Next, the Company incorporated DER forecasts into the load forecast to determine how DERs will impact peak load.[14] The Company broke down DER treatment on the load forecast based on the resource type. The Company considered the following in load forecasting:

- DER Treatment in the Corporate Load Forecast
    - Distributed Solar PV
    - Electric Vehicles
    - Large Customer Adjustments
- DER Forecasts in
    - Distributed Solar PV
    - Distributed Wind Generation
    - Distributed Energy Storage
    - Energy Efficiency
    - Demand Response
    - Electric Vehicles
- Impact of the IRA on Forecasting
    - Electric Vehicles

[11] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 8 (PDF p. 63)
[12] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 30 (PDF p. 85)
[13] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 30 (PDF p. 85)
[14] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 31 – 32 (PDF p. 85-86)

- Solar

Figures 1 through 5 depict Xcel's corporate forecasts for various DERs.

Figure 1: Distributed Solar PV Forecast (MW_{ac})[15]

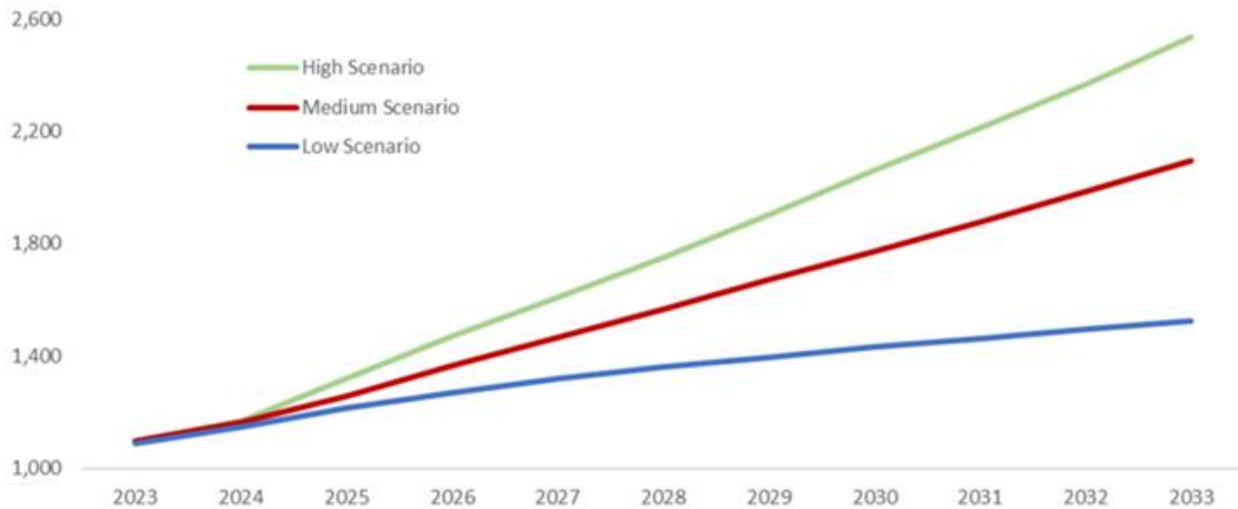
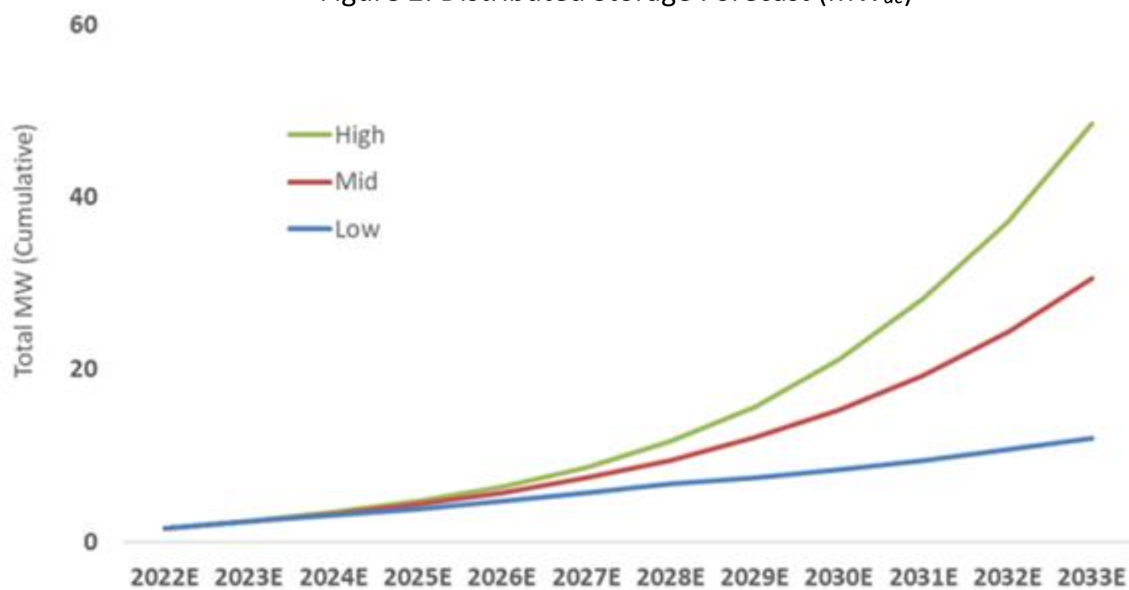


Figure 2: Distributed Storage Forecast (MW_{dc})[16]



[15] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 38 (PDF p. 93), Figure A1-10
[16] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 40 (PDF p. 95), Figure A1-11

Figure 3: Cumulative EVs[17]

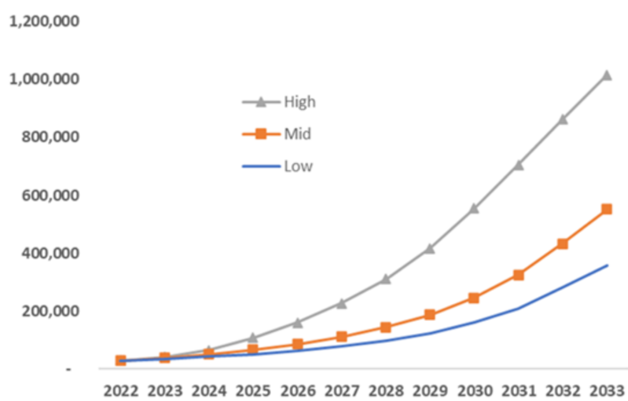
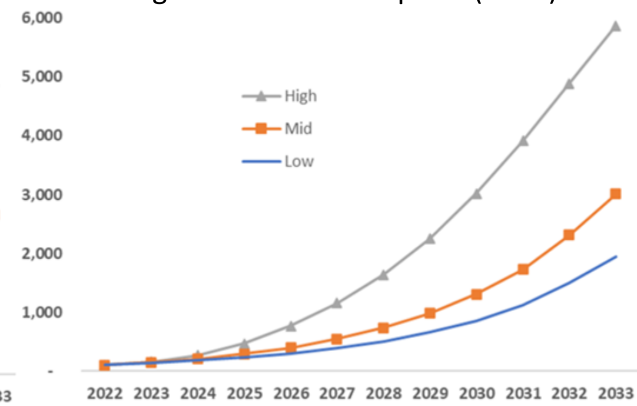
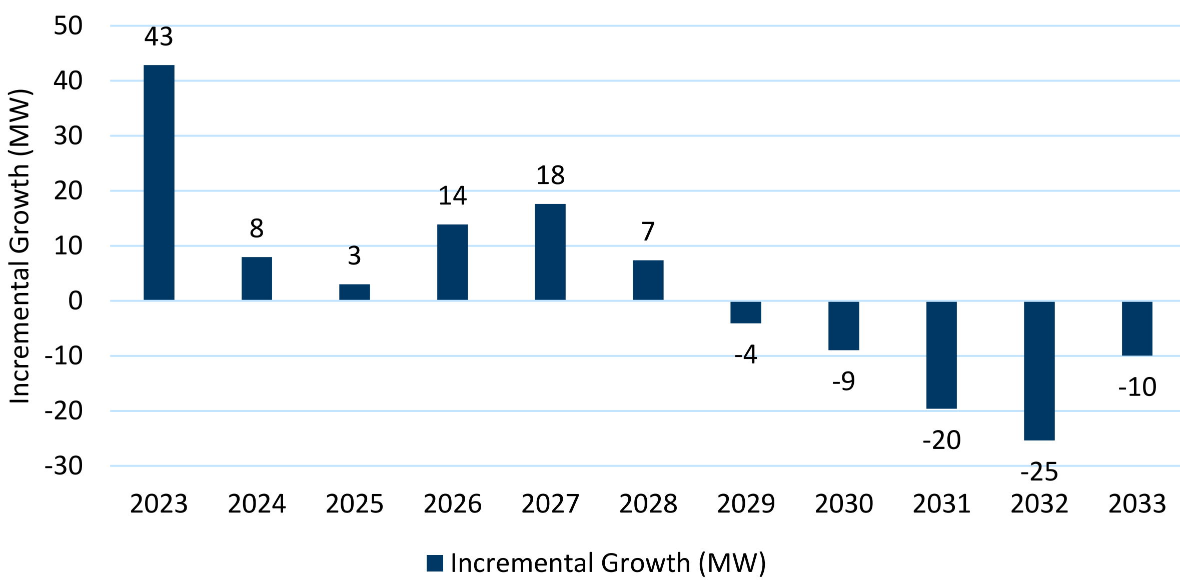


Figure 4: EV Consumption (GWh)[18]



When the Company utilizes LoadSEER DER Forecast Scenarios, the Company creates the "Budget Plan" to represent corporate energy sales and demand forecast to plan projects in the Distribution five-year capital budget.[19] This plan only contains load growth that is considered "known and expected" and represents that minimum desired funding level for capacity work to meet immediate distribution system capacity needs. Figure 5 represents the Company's incremental expected load growth from 2023 through 2033 used to develop the "budget plan" for this IDP.

Figure 5: Incremental Growth from Corporate Demand Forecast in LoadSEER



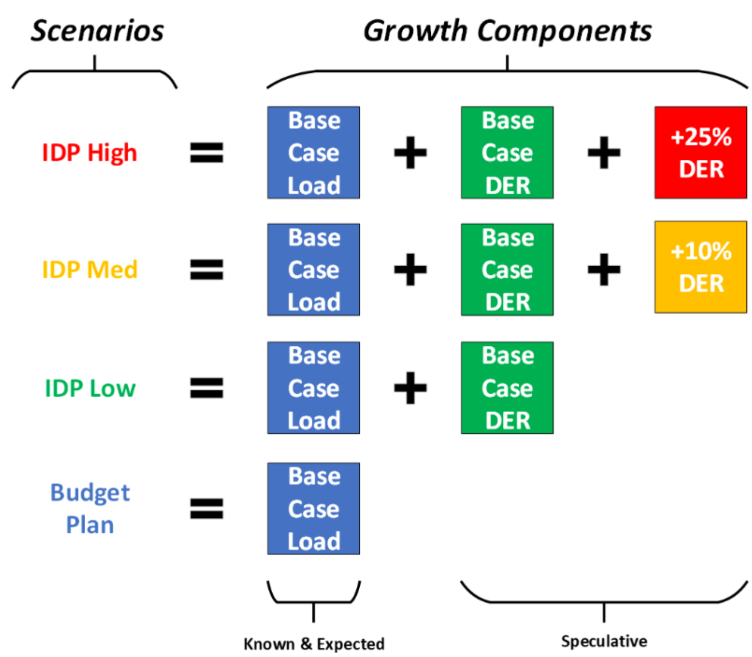
Three DER scenarios are then built off the Budget Plan by adding differing levels of speculative DER adoption based on the corporate-level DER adoption forecasts.

[17] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 46 (PDF p. 101), Figure A1-13

[18] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 47 (PDF p. 102), Figure A1-15

[19] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 49 (PDF p. 104)

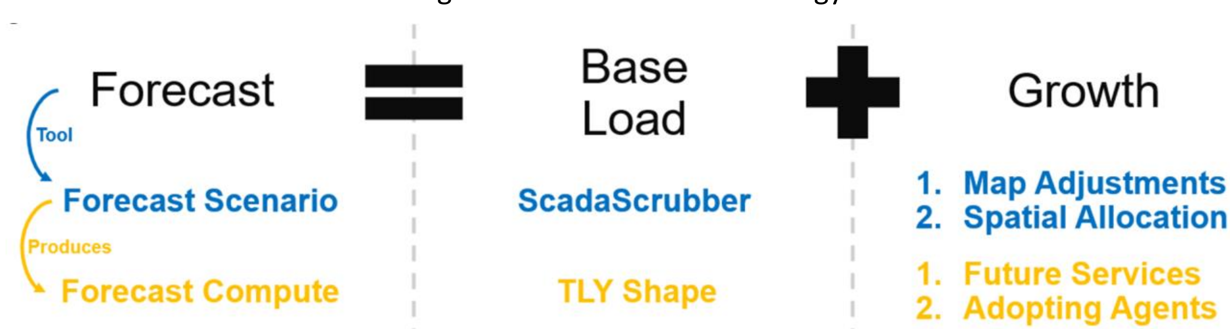
Figure 6: Scenario Definitions[20]



The LoadSEER Forecasting Methodology is a spatial load forecasting tool used by electric distribution system planners to predict how much power must be delivered, where on the grid the power is needed, and when it must be supplied.[21] It uses geospatial data, system and customer level data, historical and forecasted weather patterns, and distribution load flow application data to produce a load forecast.

The methodology used to construct a forecast is illustrated in Figure 7 by the below generalized formula.[22]

Figure 7: LoadSEER Methodology



Once the LoadSEER forecasting produces the results, those results are combined to compute the forecast for all distribution feeders and substation transformers. The Company is then able

[20] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 50 (PDF p. 105)
[21] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 51 (PDF p. 106)
[22] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 51 (PDF p. 106)

to input low, medium, and high adoption rate scenarios based upon a variety of factors, which include corporate sales and demand, EV charging, residential beneficial electrification, customer sited solar PV, and battery storage.

LoadSEER is also able to conduct load forecasting specific to load shapes for maps of feeder or substation transformer peak demand. Adjustments to maps can be used to flag areas where the Company anticipates there will be higher levels of DER penetration, such as EVs or customer sited solar. To help simulate forecasted load the Company uses spatial allocation to increase the accuracy of load growth.[23] The key function of spatial allocation is to simulate load growth across the distribution grid through a probabilistic model that helps plan distribution capacity upgrades. More specifically, each type of load growth, such as EVs or customer sited solar, is allocated a unique run of the spatial allocation designed to model the adoption of that specific technology.

This IDP is the first time the Company has used the LoadSEER for load forecast scenarios. Table 3 below describes the corporate-level DER scenarios that were used to create each of the three LoadSEER scenarios.

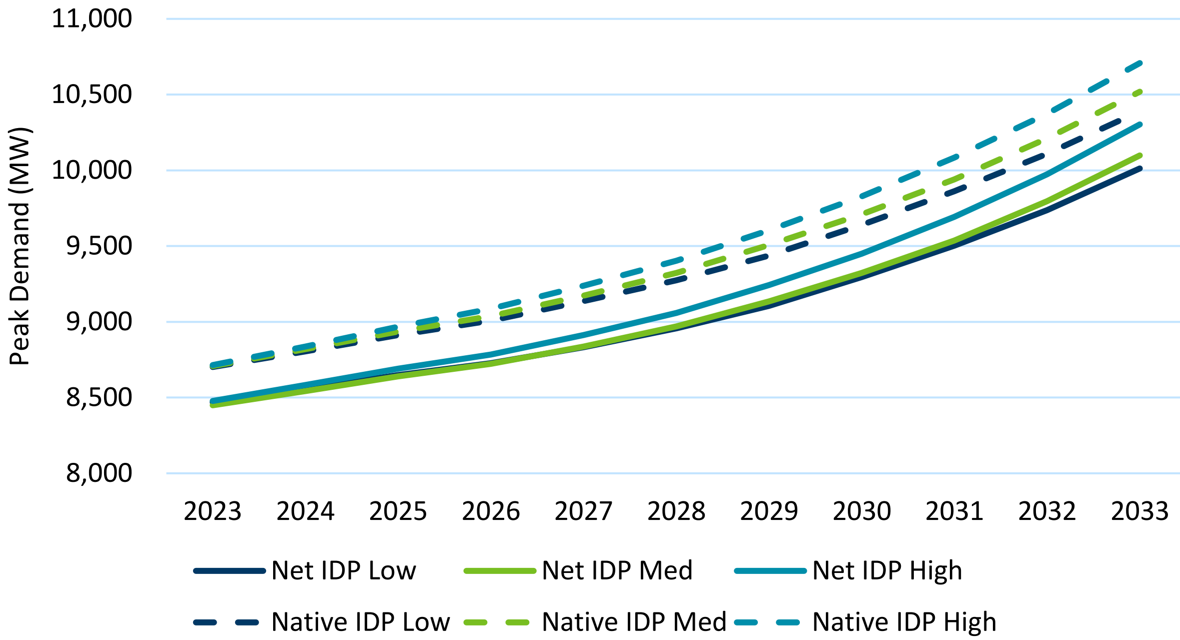
Table 3: Corporate-Level DER Scenarios Used in LoadSEER Scenario Forecasts[24]

Budget Plan	**IDP Low**	**IDP Medium (Mid)**	**IDP High**
Corporate Demand	Corporate Demand	Corporate Demand	Corporate Demand
	EV: Mid	EV: Mid + 10%	EV: Mid +25%
	BE: Base/125%	BE: Base/110%	BE: Base
	Solar FTM: Low	Solar FTM: Medium	Solar FTM: High (Legislation)
	Solar Rooftop: Medium	Solar Rooftop Medium +10%	Solar Rooftop: Medium +25%
	Battery Medium	Battery: Mid +10%	Battery: Mid +25%

When those different load growth factors are put into the LoadSEER forecast and different scenarios are produced, it results in the total non-coincident peak demand. It then can be broken down by scenario according to native and net loading. Native loading is the actual demand when all DER generation impacts are excluded. Net loading is the actual demand when all DER impacts are included.

[23] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 53 (PDF p. 108)
[24] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 57 (PDF p. 112)

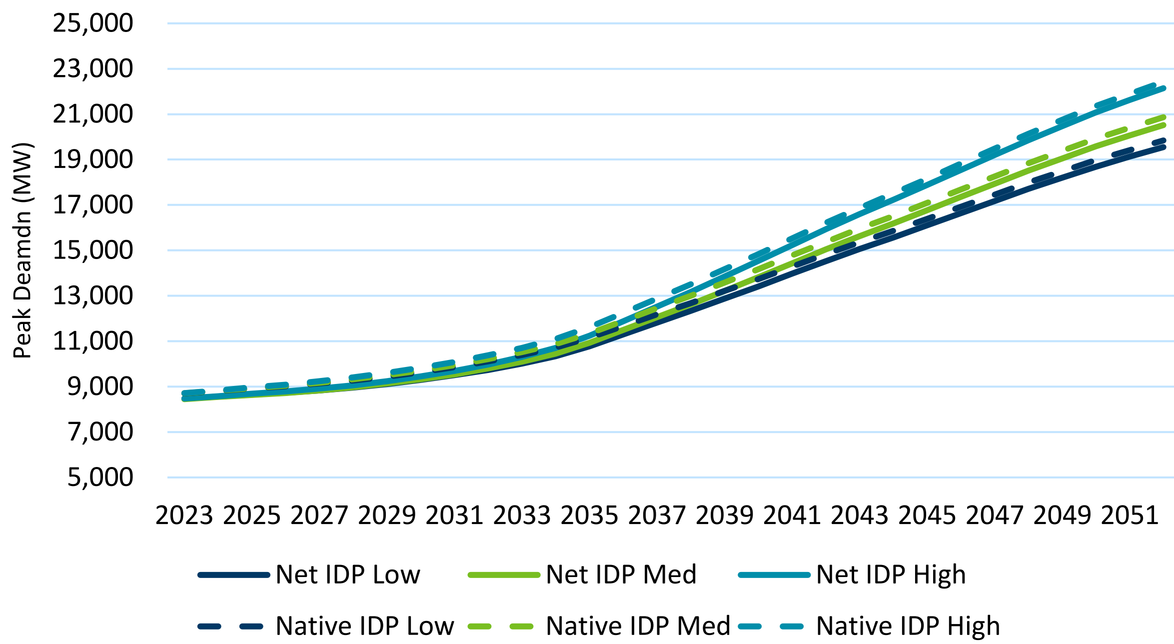
Figure 8: Total Non-Coincident Distribution Peak Demand Forecast
Aggregated Distribution Feeder Peak Load - Minnesota[25]



As shown, the aggregate total of non-coincident feeder peak demands on the distribution system in Minnesota is expected to increase from 8.5 GW in 2023 to 10.5 GW by 2033.[26] When the forecast is considered on a 30-year timeframe, the non-coincident feeder peak demand increases to 20 GW.[27]

[25] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 67 (PDF p. 122)
[26] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 67 (PDF p. 122)
[27] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 68 (PDF p. 123)

Figure 9: Total Non-Coincident Distribution Peak Demand 30-year Forecast – Aggregated Feeder Peak Load[28]



Lastly, the Company stated it is supportive of community energy, climate, and broader sustainability goals and aims to help them achieve their goals. The Company explained it is challenging to incorporate each community energy goal directly into the LoadSEER because the system does not conform to local jurisdiction boundaries. However, the Company believed the "high" DER forecast scenarios would meet the community goals in the aggregate.[29]

i. GEC – Initial Comments

GEC supported Xcel's efforts to incorporate LoadSEER forecasting into its distribution planning process.[30] GEC emphasized the relationship between DER forecasting and proactive spending. They further emphasized that beyond investigating additional investment the Company may need to make, the Company will also need to continue to explore other ways to lower its spending, including through leveraging the growing volumes of DERs on its system and improving equity in DER access.[31] GEC also explained that the Commission should require Xcel to incorporate changes in load from rate design such as the proposed default TOU rate for residential customers, along with incorporating the impacts of demand response and load flexibility.[32] (**Decision Option 5**) The GECs also encouraged the Commission to require Xcel

[28] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 68 (PDF p. 123)
[29] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 70 (PDF p. 125)
[30] GEC, Initial Comments, March 1, 2024, p. 36
[31] GEC, Initial Comments, March 1, 2024, p. 37
[32] GEC, Initial Comments, March 1, 2024, p. 35-36

Energy to take additional steps to develop load flexibility pilots for residential customers to maximize opportunities to reduce peak load.[33] (**Decision Option 6**)

i. Fresh Energy – Initial Comments

Fresh Energy was pleased that the Company has begun to incorporate LoadSEER into its planning processes, but it concerned that Xcel is not using the LoadSEER results to inform its capital investment plan.[34] Fresh Energy believed developing a distribution budget based on technology adoption forecasts raises several important questions about prudency, cost-effectiveness, and equity.

While Fresh Energy appreciated the use of three main forecasting scenarios, these scenarios do not quantify potential infrastructure needs or costs in the short or long-term. Further, Fresh Energy requested that future beneficial electrification forecasts include commercial and industrial electrification as the Company currently only considers residential electrification.[35]

ii. Department – Initial Comments

The Department noted it is not possible to provide technical comments on Xcel's forecasting results and methodology without base forecast data, explanation of changes to the input data, variables that were considered, the forecast outputs, statistical measures of the forecast's accuracy, and so forth.[36] Therefore, the Department recommended that in Xcel's next IDP the Company provide the following for its LoadSEER forecasts: (**Decision Option 9**)

a. a complete list of the data sets used in making the LoadSEER forecast, including:
    i. a brief description of each data set and
    ii. an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer);
b. a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:
    i. the nature of the adjustment,
    ii. the reason for the adjustment, and
    iii. the magnitude of the adjustment;
c. a discussion of each essential assumption made in preparing the LoadSEER forecast, including:
    i. the need for the assumption,
    ii. the nature of the assumption, and
    iii. the sensitivity of forecast results to variations in the essential assumptions;
d. an equation showing the LoadSEER forecast model:
    i. for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …
e. information documenting the LoadSEER forecast's confidence levels including statistical accuracy of the individual variables and overall model=; and

[33] GEC, Initial Comments, March 1, 2024, p. 53-54
[34] Fresh Energy Initial Comments March 1, 2024, p. 12
[35] Fresh Energy Initial Comments March 1, 2024, p. 12-13
[36] Department of Commerce Initial Commerce March 1, 2024, p. 51

f. the outputs from the LoadSEER forecast.

The Department also recommended that the Commission require Xcel to provide a comparison of the forecast provided in the IDP to actuals. (**Decision Option 10**)

Additionally, Department noted the short time the Company had to consider IRA benefits in its 2023 IDP and anticipates IRA incentives will be addressed further in future IDPs. However, the Department noted Company's forecasting may be enhanced with the inclusion of IRA incentives of DERs, EVs, and electrification measures, such as heat pumps. Lastly, the Department believed commercial and industrial customer forecasts would have benefited from IRA incentive inclusion.[37]

iii. Minneapolis – Initial Comments

The City of Minneapolis appreciated the Company incorporating IRA incentives into its forecasted adoption rate for EVs and distributed solar.[38] However, Minneapolis believed that a 20 percent increase in EV adoption and a 30 percent increase in distributed solar may be low compared to customer interest in IRA opportunities. Minneapolis also noted that it may be beneficial to consider electrification adoption rates in general due to federal incentives for space heating and water hearting. Minneapolis asked the Company to complete an analysis of IRA benefits holding a stronger customer influence as part of its next IDP.[39] (**Decision Option 12**)

iv. Xcel Energy – Reply Comments

The Company viewed the Department's recommendations as "extremely problematic."[40] First, much of the information included in LoadSEER is intellectual property of LoadSEER, the Company is simply a user of the tool. Second, all assumptions used in the LoadSEER, and the load forecasting process were included in *Appendix A1* of the Company's 2023 IDP. Requesting additional levels of information would be unnecessarily burdensome.[41]

In response to Fresh Energy's comments, the Company agreed it is important to have robust and methodologically sound forecasting. The Company agreed forecasting would be more well-rounded if the Company followed up with the forecast scenario analysis with a capital expense analysis and envisions a high-level analysis that could be realistic in the future. However, conducting such an analysis would be a monumental task and require additional staff.[42]

Additionally, the inclusion of commercial and industrial beneficial electrification forecasts is one avenue the Company is looking to advance in its DER forecasts. However, as stated in the 2023 IDP, commercial and industrial beneficial electrification forecasts are still under development and will be incorporated into the IDP when available with or without an order point from the Commission.[43]

[37] Department, Initial Commerce, March 1, 2024, p. 55-59
[38] Minneapolis, Initial Comments, March 1, 2024, p. 4
[39] Minneapolis, Initial Comments, March 1, 2024, p. 4-5
[40] Xcel Energy, Reply Comments, March 22, 2024, p. 41
[41] Xcel Energy, Reply Comments, March 22, 2024, p. 42
[42] Xcel Energy, Reply Comments, March 22, 2024, p. 42
[43] Xcel Energy, Reply Comments, March 22, 2024, p. 42

While the Company agreed that forecasts are inherently uncertain and not always a guarantee of the future, the Company tries to mitigate risks by developing plans that offer a wide range of potential outcomes. Therefore, the Company requested the Commission decline the Department's recommendations regarding LoadSEER and Fresh Energy's recommendation because the Company will incorporate commercial and industrial beneficial electrification into future IDPs.[44]

In response to the Department and the City of Minneapolis on incorporating the impacts of the Inflation Reduction Act, the Company provided that it has a robust forecasting process which accounts for and updates on the impacts of the Inflation Reduction Act.[45] Further, the Company did not agree with the City of Minneapolis that it needs to double the load forecasting for EVs and customer sited solar due to Inflation Reduction Act incentives because it could risk overbuilding and incurring needless rate increases as many vehicles on the market do not qualify for the tax credit and the lack of public charging stations.[46]

In response to GEC's recommendations Xcel explained that it is premature to include the impacts of TOU rates as part of its load forecast as the Commission has not yet decided on that docket. The Company indicated it will continue to monitor DR and load flexibility and "will forecast them as additional data is available."[47]

v. GEC – Reply Comments

GEG explained that while the default TOU rate may still be pending, the Commission can still set an expectation for the Company to incorporate the impacts of new advanced rate design proposals that are approved into future load forecasts. Similarly, GEC encouraged the Commission to make incorporation of demand response and load flexibility into Xcel's forecasts explicit for future IDPs.[48]

vi. Fresh Energy – Reply Comments

Fresh Energy appreciated Xcel's response to its recommendation to improve beneficial electrification forecasts, evaluate the accuracy of LoadSEER forecasts, and explore using different forecast levels to perform sensitives on capital budgets. Fresh Energy requested the Company continue to report on its progress on these items in its next IDP. Further, Fresh Energy requested the Company develop a commercial and industrial beneficial electrification forecast as part of its next IDP or explain why the Company is unable to complete one by that time. Related, Fresh Energy recommended Xcel report on progress to refine its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios.[49] **Decision Option 7** incorporates Fresh Energy's recommendations.

vii. Department – Reply Comments

---

[44] Xcel Energy, Reply Comments, March 22, 2024, p. 43
[45] Xcel Energy, Reply Comments, March 22, 2024, p. 43
[46] Xcel Energy, Reply Comments, March 22, 2024, p. 44
[47] Xcel Energy, Reply Comments, March 22, 2024, p. 45
[48] GEC, Reply Comments, April 12, 2024, p. 20-21
[49] Fresh Energy, Reply Comments, April 12, 2024, p. 5

In reply to the Company's reply comments, the Department noted that Xcel has the burden of proof to demonstrate the actions the Company takes based on LoadSEER forecasts are reasonable. Therefore, the Company may need to provide additional information to demonstrate reasonable investments.[50] The Department recommended that the Commission order Xcel Energy to adopt a forecast method that is reviewable by the Department and other parties for the Company's next IDP. (**Decision Option 11**)

viii. Staff Analysis

Staff applauds Xcel's first forecast using LoadSEER in its 2023 IDP. While there are still steps to be taken to incorporate the use of these forecasts into planning processes, this should be seen as a monumental step forward to better plan and use the distribution system to meet the energy transition. In February of 2024 Staff meet with Xcel Energy's technical experts and received a walkthrough of LoadSEER, a summary of which is available in an ex parte report filed in the present docket. Staff found the walkthrough to be helpful in understanding the capabilities and complexities that go into creating the LoadSEER forecast and encourages the Company to make similar walkthroughs available on an informal basis to other participants in IDP proceedings. In particular, Staff believes that the information provided in the walkthrough could answer many of the questions and concerns raised by the Department as reflected in **Decision Option 9**. Staff does not recommend adoption of **Decision Option 11**.

Staff agrees with GEC that Xcel should improve its forecasting of demand response and load flexibility. In reviewing Xcel's IDP, Staff was unable to find standalone forecasts of demand response, load flexibility, or energy efficiency as it does for solar, electric vehicles, and energy storage. While Xcel may incorporate the impacts of these technologies into its load forecast, it does not break out these technologies independently. Staff notes that Xcel Energy's IDP filing requirements define DERs as:

> Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.[51]

Therefore, Staff believes it is reasonable to require Xcel to provide forecasts in its next IDP. Staff provides **Decision Option 8** which explicitly requires the Company to provide standalone forecasts for demand response, load flexibility, and energy efficiency.

D. Filing Requirement Modifications

i. Modification of Filing Requirement 3.A.9

Xcel provides the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system, as required by

[50] Department, Reply Comments, April 12, 2024, p. 15
[51] Xcel Energy, IDP Filing Requirements at p. 3, see attachment to November 18, 2023 Notice of Comment in the present docket

IDP Requirement 3.A.9, which is 9,245 MW which occurred at 5:00 p.m. on June 20, 2022 with the Minnesota portion of the peak being 6,973 MW.[52]

However, the Company claimed that providing this data is time and resource intensive because it is a manual process where each SCADA-enabled substation for the data and time of the NSP System must be accessed. Additionally, in the last IDP the Company asked for feedback from stakeholders about how this information may be helpful to them or how it was intended to be used. Xcel reports that none of the stakeholders replied to these questions and in light of that lack of response, the manual process of this requirement, and the additionally new IDP requirement for future IDPs that have been tasked of the Company, they requested that the requirement be discontinued.[53]

First, the Department comments on the Company's request to discontinue IDP Requirement 3.A.9,

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

The Department is not opposed to the Commission discontinuing this IDP requirement because the Company describes the obligation to fulfil this requirement is time and resources intensive that requires approximately four hours to complete.[54] Xcel notes that in prior IDPs, it completed the manual process to fulfill this requirement and sought input from stakeholders regarding the value of the information and how it could provide the desired information in a more efficient. However, the Company received no such feedback and requests the IDP filing requirement be discontinued. The Department does not oppose the Company's position if doing so would eliminate requirements that do not provide value.

Fresh Energy also recommended discontinuing the filing requirement.[55] Minneapolis does not take a position on this whether this requirement should be discontinued.[56]

Staff does not object to the discontinuation of the filing requirement.

Decision Option 13 adopts Xcel's recommendation

ii. Modification of Budget Reporting Filing Requirements

The Company requested a modification of filing requirements 3.A.26, 3.A.28, and 3.A.29 in its initial IDP filing. A summary of the modification and Staff recommendations can be found in the Joint Briefing Papers.

Decision Option 14 adopts Xcel's recommendation
Decision Option 15 adopts Staff's recommendation

[52] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A4, November 1, 2023, p. 3 (PDF p. 175)
[53] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A4, November 1, 2023, p. 3 (PDF p. 175)
[54] Department, Initial Comments, March 1, 2023, p.55
[55] Fresh Energy, Initial Comments, March 1, 2024, p. 24
[56] Minneapolis, Initial Comments, March 1, 2024, p. 4

iii. Electrification Filing requirements

The Department recommended that the Commission "adopt a new IDP filing requirement requiring Xcel to specifically address how beneficial electrification is anticipated to affect the distribution grid and cost allocation issues thereof." This is discussed in the Joint Briefing Papers

Decision Option 16 adopts the Department's recommendation
Decision Option 17 adopts Staff's recommendation

E. Resiliency

Xcel acknowledged that reliability and resiliency often overlap as both aim to reduce the number and duration of outages on the distribution system. Reliability focuses on the "day-to-day performance of the grid," while resiliency "focuses on improving the distribution system's ability to withstand, endure and recover from significant events that can create widespread outages and result in long-duration restoration times."[57] The Company reiterated its strategy throughout the IDP is to replace aging assets and harden the distribution system to make it more resilient due to more frequent and severe extreme weather events.

The Company's investments to enhance the resiliency of the distribution system include substation transformers, breakers, and associated gear along with distribution poles, overhead and underground feeders as well as overhead and underground taps, pole inspection and vegetation management.[58] These investments can be divided into asset health, cybersecurity, and physical security investments.

[57] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 17 (PDF p. 34)
[58] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 4 (PDF p. 22)

Table 4: Asset Health Investments[59]

Project	Description
Vegetation Management	Increased spending from $27.8 million in 2023 to $42.8 million in 2028.
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. Intended to provide both fuse-saving sand fuse-blowing schemes.
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 will improve system performance especially during high wind conditions, icing, and heavy snow.
Substation Renewal Program	Focused on improving the reliability and resiliency of the Company's substations through the replacement of key substation components.
Transition to Conduit Mainline Cables	This type of construction improves the reliability of our underground system by protecting our underground cables from the elements and wildlife.[60]

Cyber Security Investments

The Company's cyber security investments, which aim to enhance the resiliency of the distribution system, are those consistent with Governor Walz's Executive Order 22-20 directing state agencies to monitor and reduce cybersecurity risk to critical infrastructure. The Company continues to work with the Department to enhance resiliency of the distribution against cyber security threats.

Physical Security Investments[61]

Due to an increase in planned and executed attacks on traditional bulk electric system substation locations, the Company is working to expand physical security efforts. The asset evaluations will result in recommendations to mitigate possible physical security risk at Company substations.

[59] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, Appendix A2, p. 7 (PDF p. 151)
[60] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, Appendix A2, p. 12 (PDF p. 156)
[61] Xcel Energy, 2023 IDP Part 2 of 3, November 1, 2023, Appendix B2, p. 5-6 (PDF p. 55-56)

Table 5: Resilience Improvements

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

Other notable investments which enhance the resiliency of the Company's distribution grid are the School Bus Vehicle-to-Grid Demonstration and Resilient Minneapolis Project. Both projects are under development but can provide backup generation resources to an isolated location during an outage. Further, the School Bus Vehicle-to-Grid Demonstration can act as demand response and distributed energy resources for grid resiliency.

i. Department – Initial Comments

Resiliency Performance Metrics[62]
The Department's primary concern was that Xcel's resiliency strategy is not sufficiently different from the Company's approach to reliability. Xcel defines "resiliency" as "the system's ability to withstand, endure, and recover from significance events that can create widespread outages and results in long-duration restoration times."[63] The Company planned to improve system resiliency "by investing in projects that allow us to maintain reliable serve for our customers and to harden our system against extreme weather events, as appropriate."[64] Further, the Department noted Xcel's strategy that improving reliability will, in turn, improve the distribution system's resiliency.

To track the distribution system's resiliency performance, the Company believed tracking SAIDI and SAIFI, which "are directionally correlated to resiliency," will provide an indication of resiliency performance. The Department agreed that SAIDI, SAIFI, and other traditional reliability metrics may provide an indication of resiliency performance but stressed that the focus for resiliency should be on the non-weather-normalized versions of these metrics that include Major Event Days.

The Department recommended that the Commission direct Xcel Energy to develop a suite of metrics to track resiliency, including SAIDI and SAIFI, MEDs, and other metrics to the extent warranted. (**Decision Option 18**)

---

[62] Department, Initial Comments, March 1, 2024, p. 47
[63] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 17 (PDF p. 34)
[64] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, Appendix A2, p. 1 (PDF p. 145)

Sandia Resiliency Performance Metrics[65]

To aid in the development of resiliency performance metrics, the Department offered a resiliency report series published by Sandia National Laboratory in 2021. The report clarified that while reliability is primarily about the grid's functionality on a day-to-day basis, resiliency has to do with the grid's ability to mitigate the impact of severe events on customers and critical services. Identifying at-risk customers and geographies is thus crucial in measuring resiliency performance and targeting resiliency investments effectively. One approach to tackling resiliency is to separately track performance during Major Event Days (MED) for different tiers of customers and for different regions. Customer tiers should be established according to the consequences of losing power. Regions could be categorized into high-risk, medium-risk, and low-risk depending on the consequences of the outage. Segmenting resiliency performance metrics could allow Xcel to optimize resiliency investments.

The Department offered Table 6 to aid in developing Resilience Performance Metrics

Table 6: Department Resilience Performance Metrics

Category	Customer Tier	Geographic Tier	Event
Report before a major outage event	• Number of customers, percent of total • Number of critical customers, percent of total • Load, percent of total load • Number of island-able resources	• Number of substations and critical substations • Number of feeders and critical feeders • Number of customers served per substation and feeder	• Frequency, number of events • Average duration of each event • Event probability
Report during a major outage event	• Number of affected customers and critical customers • Departed Customers • Departed Load • Number of island-able resources that functioned during event	• Number of affected substations and critical substations • Number of affected feeders and critical feeders • Percent of affected substations and feeders of total	• Duration of event • Utility staff impacts (injuries or deaths, percent affected) • Utility infrastructure impacts ($ damages) • Non-staff impacts (injuries or deaths, percent affected) • Non-utility infrastructure impacts ($ damages to customers, services, etc.)

[65] Department, Initial Comments, March 1, 2024, p 48

The Department recommended that the Company propose a set of resiliency performance metrics such as Sandia's that encompass broad system impacts, in addition to SAIDI and SAIFI. (**Decision Option 19**)

ii. Minneapolis – Initial Comments

The City of Minneapolis appreciated the Company's proposed $200 million investment to increase interconnection capacity but reiterates that such investments should be made with equity considered. Specifically, the City of Minneapolis believes the funds should be aimed at addressing hosting capacity limits in the Minneapolis Green Zones because these zones have between a 59% to 85% higher incidence of long-duration outages compared to other Xcel Energy customers in Hennepin County.[66]

iii. Xcel Energy – Reply Comments

The Company believed that creating additional goals and metrics, and reporting those in the IDP, would be overly duplicative of existing reliability metrics. It indicated a discussion around resiliency may be better suited in current reliability reporting dockets.[67] The Company currently reports on SAIDI, SAIFI, CEMI, CELI, CAIDI, and MAIFI with normalized and non-normalized values in its Annual Service Quality docket. Therefore, the Company believed resiliency information should not be reported in the IDP but rather in the Annual Service Quality filing.

In response to a Commission's Information Request regarding equipment design standards to withstand increasing extreme weather events, the Company shared it is continually performing research and implementing standards to improve resiliency and reliability. Specifically, revisions to the Distribution Design and Construction Standards occur every two years as supported by research performed in-house and the Electric Power Research Institute. As a result of this research, the Company has implemented the following system upgrades:

- Fiberglass crossarms (2012 and 2014)
- Transition to NESC Grade B construction (2014)
- Wildfire construction standards (2020-present)

Current research projects and workgroups include:

- Cable and transformer loading impacts due to EV adoption, electrification of the gas system, and DERs
- IEEE Insulated Conductor Committee
- IEEE C37 Switchgear Committee

Lastly, the Company utilizes its load forecasting software, LoadSEER, for a weather normalization and simulation tool to simulate system loading under a user-specific percentile of extreme weather based on 30 years of historical weather data. This allows the Company to understand the demands on the distribution system under extreme weather events.[68]

[66] Minneapolis, Initial Comments, March 1, 2024, p. 4
[67] Xcel Energy, Reply Comments, March 22, 2023, p. 39-40
[68] Xcel Energy, Response to PUC IR 1, May 17, 2024

iv. Department – Reply Comments

The Department continued to recommend Xcel develop a suite of metrics to track resiliency. Specifically, the Company should track SAIDI at system and subsystem levels, with and without major event days, and SAIFI, at the system and subsystem levels, with and without major event days. The Department continued to recommend that reliability and resiliency metrics should be discussed in the IDP because it provides useful information to guide decisions around future distribution planning and investment.[69]

The Department continued to emphasize that tracking reliability is different from tracking resiliency. Xcel provided a definition of "resiliency" that differed from reliability and the Department continues to believe tracking resiliency metrics will allow the Company to measure the system's ability to withstand, endure, and recover from outage events.

v. Staff Analysis

Staff discusses the Department's recommendations for establishing resiliency metrics in the Joint Briefing papers and maintains its recommendation that there is nearly identical overlap between what the Department is recommending in **Decision Option 18** and the annual SQSR reports, therefore an additional set of metrics would be duplicative.

The Department did recommend an extra requirement for Xcel that was not mentioned in the other utility IDPs, that the Company "propose a set of resiliency performance metrics such as Sandia's that encompass broad system impacts." Staff notes that the Sandia report provides a starting point for metrics that considers the impact of major outage events by customer tiers and regions. This report categorizes customers depending on the level of consequence, prioritizing high-risk outage customers or regions, or critical customers, when the Company considers resiliency investments in its distribution system. Staff believes a discussion of how the Company track and considers the restoration of critical customer load, such as hospitals and first responder sites during extended outage events could be a useful addition to resiliency discussions and aid the Commission in whether it is necessary to develop metrics in line with what Sandia recommends. Therefore, Staff offers a modified version of the Department's recommendation in **Decision Option 20**.

6. Equity and Energy Justice

i. GEC – Initial Comments

GEC highlighted recent actions taken by the Commission to recognize efforts to incorporate and address equity in utility planning processes including the IDP. GEC offered a definition of energy justice as "the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system." GEC believe that energy justice is an equally important planning objective to safety, reliability, efficiency, and affordability, but it has yet to be incorporated into the IDP process. [70]

[69] Department, Reply Comments, April 12, 2024, p. 11-12
[70] GEC, Initial Comments, March 1, 2024, p. 9

In order to better quantify and identify existing disparities in Xcel's distribution system, the GEC included a summary of an independent analysis performed by Dr. Bhavin Pradhan and Dr. Gabriel Chan from the University of Minnesota Center for Science, Technology, and Environmental Policy. The study used regression analysis to determine whether there were disparities in reliability, disconnections, and hosting capacity within Xcel's Minnesota service territory. The analysis uses the Climate and Economic Justice Screening Tool (CEJST) developed by the Biden Administration to implement the Justice40 initiative to identify "disadvantaged" communities.[71] The study made the following findings:

- Extended Outages: Between 2018 and 2021 households in CEJST communities had a statistically significant higher rate of an extended outage in a year (outages of over 12 hours, also known as CELI-12) than households in non-CEJST communities throughout the Company's service territory.[72]
- Multiple Outages: there was limited evidence of disparities in customers facing multiple outages (customer experiencing more than 6 outages in one year, CELI-6), with only 2017-2019 having any statistical significance. Overall, results were not statistically significant when looking at a wider timeframe.[73]
- Involuntary Disconnections: there was significant evidence of disparities in disconnections for when controlling for income, race, and disadvantaged communities.[74]
- Hosting Capacity: disadvantaged communities had 37% higher hosting capacity than non-CEJST communities, showing there are not disparities in grid availability for DERs.[75]

GEC advocated for using DERs to advance energy justice, stating that local ownership of distributed technologies would increase wealth and community resilience for marginalized communities. In GEC's opinion, grid planning is crucial to this effort and incorporating energy justice tenants within the existing IDP framework will help advance these goals. The GECs "envision a distribution system that enables all communities, and particularly frontline communities and "environmental justice areas," to participate fully in the clean energy transition."[76]

ii. Xcel Energy – Reply Comments

The Company appreciated comments from GEC and Minneapolis on equity and agreed that focusing on the integration of equity and environmental justice into different facets of its business practices.[77]

In response to the Pradhan/Chan study, Xcel outlined the results of its own forthcoming analysis looking at disparities in service quality and reliability on its distribution system. As directed by the Commission's May 18, 2023 Order in Docket 20-406, Xcel's study examined

---

[71] GEC, Initial Comments, March 1, 2024, p. 10-11
[72] GEC, Initial Comments, March 1, 2024, p. 11-12
[73] GEC, Initial Comments, March 1, 2024, p. 13
[74] GEC, Initial Comments, March 1, 2024, p. 15
[75] GEC, Initial Comments, March 1, 2024, p. 19
[76] GEC, Initial Comments, March 1, 2024, p. 20-21
[77] Xcel Energy, Reply Comments, March 22, 2024, p. 5

whether there are disparities in disconnections, reliability, and participation in low-income programs. In addition to the demographic and income indicators on the service quality map, Xcel also included additional data points like housing vintage, English proficiency, access to Company payment center, home computer, and internet access.[78] Xcel's study had the following results:

- CELI-12 and race only had a strong negative relationship in neighborhoods with older housing stock.[79]
- CEMI-6 had a limited, and not statistically significant, negative relationship.[80]
- On disconnections, Xcel's analysis showed similar to results to the Pradhan/Chan study.[81]
- While Xcel's study did not examine hosting capacity availability, it agreed with the results of Pradhan/Chan.[82]

However, Xcel disagreed with GEC's conclusion that the results of the Pradhan/Chan study necessitated action in the IDP. In Xcel's opinion, the proper venue to discuss and take action on the results of both equity analysis is in the Reliability and Service Quality, where the Commission originally ordered the analysis.[83]

i. GEC – Reply Comments

GEC similarly disagreed with Xcel's assertion that the conclusions from the Pradhan/Chan study and Xcel's own analysis belong in the service quality report, and not in the IDP. GEC also provided a rebuttal to Xcel's interpretation of the correlation between CELI-12 and race, stating that "it is inappropriate to draw conclusions about the relationship between race and outcomes, such as electric reliability, by controlling for housing quality because housing quality is so strongly impacted by race."[84] GEC noted that Xcel provided potential solutions such as improved vegetation management and targeted undergrounding to remedy identified reliability disparities in the service quality report, however in GEC's opinion consideration of those practices belong within the IDP where overall distribution planning discussions occur.[85]

In regard to involuntary disconnections, GEC noted that Xcel outlined its existing affordability programs, but in GEC's estimation these programs had been in place for many years and had not fully addressed the disparities identified in either study. Due to the ongoing and significant racial disparities present in disconnections GEC recommended the Commission order a study on the costs and benefits of resuming a disconnection moratorium, which could then be used to

---

[78] Xcel Energy, Reply Comments, March 22, 2024, p. 6
[79] Xcel Energy, Reply Comments, March 22, 2024, p. 6
[80] Xcel Energy, Reply Comments, March 22, 2024, p. 6
[81] Xcel Energy, Reply Comments, March 22, 2024, p. 7
[82] Xcel Energy, Reply Comments, March 22, 2024, p. 7-8
[83] Xcel Energy, Reply Comments, March 22, 2024, p. 9
[84] GEC, Reply Comments, April 12, 2024, p. 6
[85] GEC, Reply Comments, April 12, 2024, p. 8-9

evaluate whether a moratorium would be warrant until disconnection disparities are eliminated.[86] **(Decision Option 21)**

Finally, GEC noted that while existing hosting capacity data largely shows hosting capacity is higher in underserved communities, it believed a more granular hosting capacity analysis could assist in identifying areas with unequitable access to DERs. GEC explained that the greater amount of hosting capacity in low-income communities "may be related to the relative lack of DER adoption in these communities to date and/or the co-location of large customers in these communities that have required significant infrastructure investments." According to GEC, this highlights the importance of implementing additional policies to bring more DERs to these communities outside of the IDP.[87]

GEC also recommended the Commission "reject Xcel's recommendation to isolate consideration of the disparities identified by the Xcel Equity Analysis and the Chan/Pradhan analysis in the SRSQ Docket and affirm that the IDP is the appropriate forum to evaluate and discuss distribution planning solutions to address these inequities." (**Decision Option 22**)

ii. <u>Fresh Energy – Reply Comments</u>

Fresh Energy noted that while it appreciated Xcel's initial reply comment statements about equity, the Company's later comments about equity being a "non-traditional" goal to keep separate from other planning considerations was concerning. Fresh Energy explained that "given the Company's plans for massive spending on the distribution system, Fresh Energy believes integrating principles of equity into spending decisions is appropriate and consistent with the Company's obligation to serve its customers."[88]

In response to the Pradhan/Chan study, Fresh Energy shared GEC's concern about the disparities in lengthy outages and disconnections. As a first step, Fresh Energy recommend the Commission require Xcel to track and report on CELI-12 and involuntary disconnections in neighborhoods where there were disproportionate impacts and report on them in the 2025 IDP in addition to the service quality reports and the locational reliability map. It also recommended recalculating the analysis as part of this reporting.[89] (**Decision Option 23**)

In response to Xcel's assertions that the equity analyses be discussed in the service quality docket, Fresh Energy noted that it was agnostic as to where disparities were reported and evaluated as long as solutions are implemented. However, it explained that it is appropriate to continue to discuss investments that can remedy these disparities as part of the IDP, as that is where overall distribution system spending is examined.[90]

iii. <u>Staff Analysis</u>

Staff shares the concerns of stakeholders and Xcel about disparities in service quality and reliability in the Company's service territory. Staff also understands and shares the frustration

[86] GEC, Reply Comments, April 12, 2024, p. 9-10
[87] GEC, Reply Comments, April 12, 2024, p. 11
[88] Fresh Energy, Reply Comments, April 12, 2024, p. 9-10
[89] Fresh Energy, Reply Comments, April 12, 2024, p. 10-11
[90] Fresh Energy, Reply Comments, April 12, 2024, p. 11

of stakeholders when trying to understand and determine where to raise these issues, report on them, and implement solutions that will reduce and resolve disparities among the services delivered to Xcel's customers.

These issues prompted Staff to schedule a stakeholder meeting on July 9, 2024 to discuss the critical issues raised by the Pradhan/Chan and Xcel analyses on disparities within the Company's service territory. As part of this meeting, Staff proposes to engage Xcel and stakeholders in a discussion about where to address issues related to disconnections and low-income programs, as they are not currently a topic discussed in the IDP. Regarding reliability, Staff does agree that the IDP is the proper forum to discuss how distribution investments can equitably improve reliability for underserved areas. Staff believes a discussion of how to synchronize reporting and discussions in the reliability docket with the IDP would be useful, as there is a large amount of overlap between the two dockets.

As to GEC's suggestion that the Commission order a study on the impacts of a disconnection moratorium (**Decision Option 21**), Staff notes this request was made in reply comments and there was not an opportunity for Xcel or other participants to respond. However, Staff does agree that the increasing trend in disconnections among Xcel's customers is concerning, especially in light of both the Company's and GEC's analysis of race and disconnection correlations. Staff suggests that if the Commission is not ready to order an additional study on a disconnection moratorium at this time, it could request that Staff include the topic as a point of discussion in the July 9 workgroup or in the subsequent comment period.

Additionally, as was noted in the joint briefing papers filed simultaneously to this docket, Staff sees value in a broader discussion with Xcel and stakeholders about clarifying reporting requirements across various distribution dockets. Staff believes that the reporting requirements suggested by Fresh Energy could be incorporated as part of scope of **Decision Option 33** which delegates authority to the Executive Secretary to work with Xcel and stakeholders to clarify and develop consistent reporting requirements for various distribution system data. Staff believes this will result in a more comprehensive report that will be easier for stakeholders to digest and will avoid having Xcel report duplicative data.

7. Distribution Budget

Each year, Xcel forecasts a five-year distribution budget for both capital expenditures along with operations and maintenance (O&M) costs. The Company conductions monthly and quarterly budget reviews for oversight and an analysis of variances from forecasted amounts.[91] Xcel highlighted several programs within its capital budget that will advance the Company's distribution objectives:

- A $190 million placeholder estimate for proactive system upgrades to increase DER hosting capacity.[92]

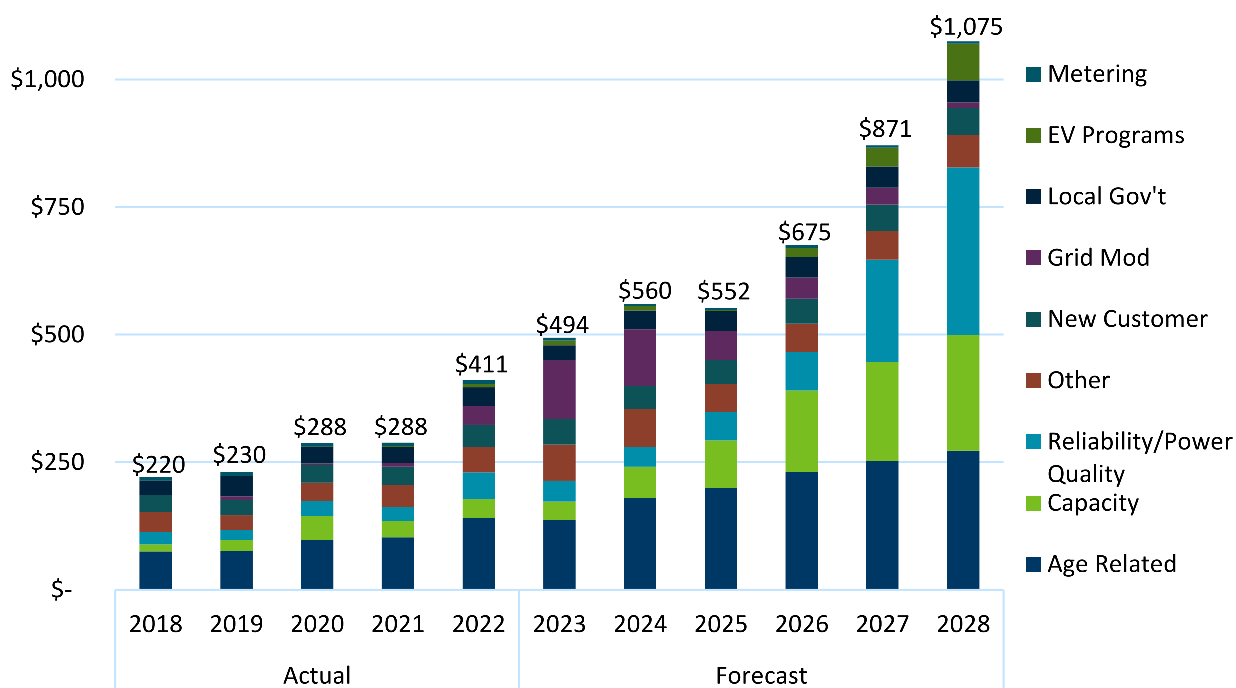
---

[91] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 3 (PDF p. 92)
[92] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 5 (PDF p. 94)

- $132 million for the Grid Reinforcements Program to proactively upgrade the grid for increased load from electrification.[93]
- Funding to enable upgrades to bring all Minnesota feeders within the Company's new targeted 75% loading level of equipment ratings.[94]
- An increased budget to harden the grid and increase reliability in response to aging infrastructure and increased extreme weather events from climate change.[95]
- Ongoing investments in approved grid modernization initiatives including Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Advanced Distribution Management System (ADMS), and Fault Location Isolation and Service Restoration (FLISR).[96]

Xcel presented its historical and forecasted budget data by IDP budget category, both in the filing and in Attachment N, which staff used to create Figure 10 below:

Figure 10: Xcel Annual Distribution Budget 2018-2028, $M[97]



Xcel explained that significant budget investments include the Grid Reinforcement Program, grid modernization initiatives as AMI rollout is completed, and potential proactive investments to increase hosting capacity. The Company noted that "recent inflation and supply chain challenges have decreased the number of investments that can be completed with existing

[93] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 6 (PDF p. 95)
[94] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 7 (PDF p. 96)
[95] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 7-8 (PDF p. 96-97)
[96] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 8 (PDF p. 97)
[97] Staff created figure from Xcel Energy, 2023 IDP Attachment N, November 1, 2023

budgets. Therefore, budgets may need to further increase to achieve the investment plans identified in the five-year budget and achieve state policy goals."[98]

i. Fresh Energy – Initial Comments

Fresh Energy (FE) highlighted the increase of over $2 billion in Xcel's capital expenditures budget across the 5-year forecast period. Specifically, FE pointed to three areas of Xcel's budget that are seeing large percent increases in spending: Age-Related Replacements and Asset Renewal (105% increase), System Expansion or Upgrades for Reliability and Power Quality (310% increase), and System Expansion or Upgrades for Capacity (323% increase).[99]

Fresh Energy sought an explanation from Xcel on drivers of the increases. For Reliability/Power Quality upgrades, Xcel explained "the increase in these out years can be attributed to our need for system hardening and resiliency. While we do not yet know how these specific dollars will be spent, we do know we have a need to address and are considering a variety of options including a potential for a more significant undergrounding program."[100] Fresh Energy noted that it believes a decent portion of what Xcel considers "asset health and reliability projects" are discretionary, meaning that they are not reactive to a power failure and Xcel has the capability to determine when, where, and how much to spend.[101]

Fresh Energy noted that Xcel's "System Expansion or Upgrades for Capacity" budget is drastically increasing yet does not include consideration of future load growth from electrification or DERs, as the Company explained that its budgeting relies on only the corporate energy sales and demand forecast, or "known and expected" load and DER growth that is based on actual customer applications.

Additionally, Fresh Energy noted Xcel has changed its planning criteria for feeder loading, changing the threshold that triggers capacity mitigations from 106% of normal rating to 75% of normal rating. In 2022, Xcel made a review of its thresholds resulting in "change that will help prepare the distribution system for the rate of growth and changes in customer expectations that are expected to occur in the future … This change is a reduction in the thresholds from what have been used historically and will help improve the availability of the distribution system to interconnect new load, such as beneficial electrification or electric vehicles before overloads are experienced."[102]

Fresh Energy examined the number of identified feeder and substation risks before and after Xcel's change to the feeder load threshold and noted that the number of risks *decreased* slightly after the 75% rating implementation, when they would have expected it to increase.[103] They requested Xcel explain why, if they had changed their threshold for risk mitigation, the number of risks on their system decreased from the 2021 IDP to the 2023 IDP. Fresh Energy requested that in reply comments the Company address why a system wide capacity threshold

---

[98] Xcel Energy, 2023 IDP Part 2 of 3, Appendix D, November 1, 2023, p. 18 (PDF p. 107)
[99] Fresh Energy, Initial Comments, March 1, 2024, p. 8
[100] Fresh Energy, Initial Comments, March 1, 2024, p. 9
[101] Fresh Energy, Initial Comments, March 1, 2024, p. 9
[102] Xcel Energy, 2023 IDP, Appendix A1, November 1, 2023, p. 81 (PDF p. 136)
[103] Fresh Energy, Initial Comments, March 1, 2024, p. 11-12

change is preferred over incorporated forecasted electrification into its budget plan, given Xcel explained the change in planning criteria resulted in the significant increases to its System Expansion and Upgrades for Capacity budget.[104]

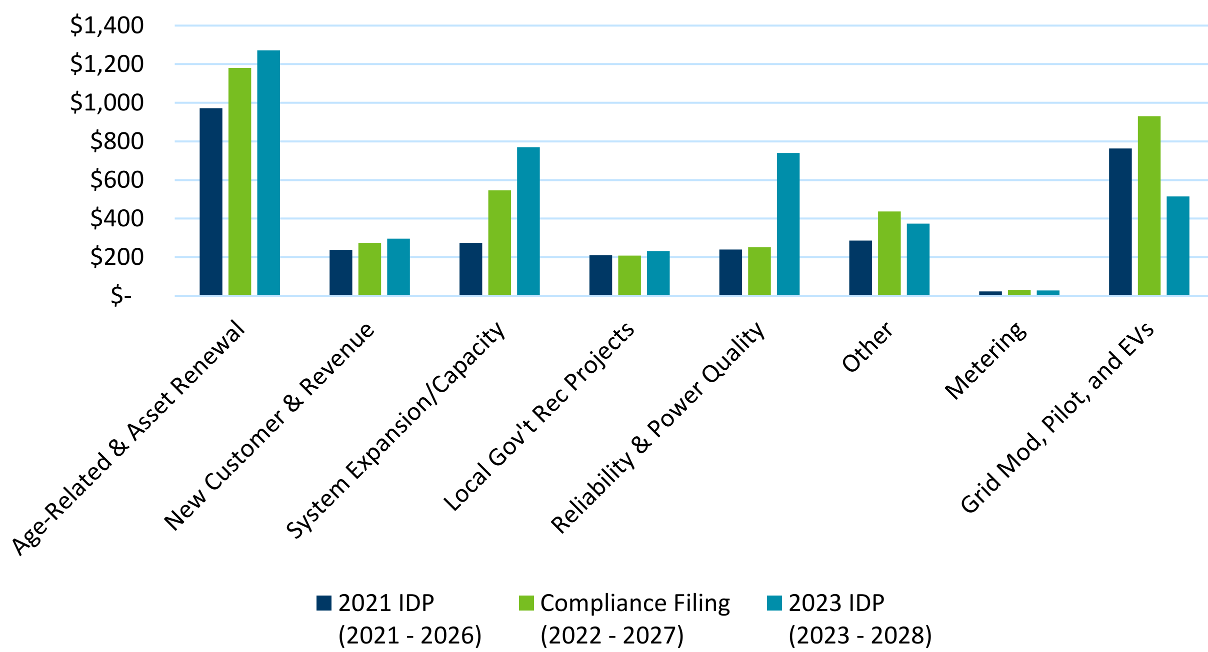
ii. GEC – Initial Comments

GEC highlighted the increases in Xcel's forecasted distribution budget, stating that while they support efforts to increase system capacity for DERs and electrification, they were concerned by the magnitude of the total budgets. Specifically, GEC was concerned at the lack of detail and justification for increases in the overall budget. They emphasized the need to ensure Xcel's planned investments are yielding intended benefits, especially those that advance energy justice and DER ownership for local communities[105]

iii. Department – Initial Comments

The Department provides a comparison of the Company's 2023 projected IDP budget to the Company's 2021 projected IDP budget and the compliance filings for that 2021 projected IDP budget, depicted in Figure 11.

Figure 11: Comparison of Xcel Distribution System Spending Projections: 2021 IDP, 2022 Compliance Filing, and 2023 IDP[106]

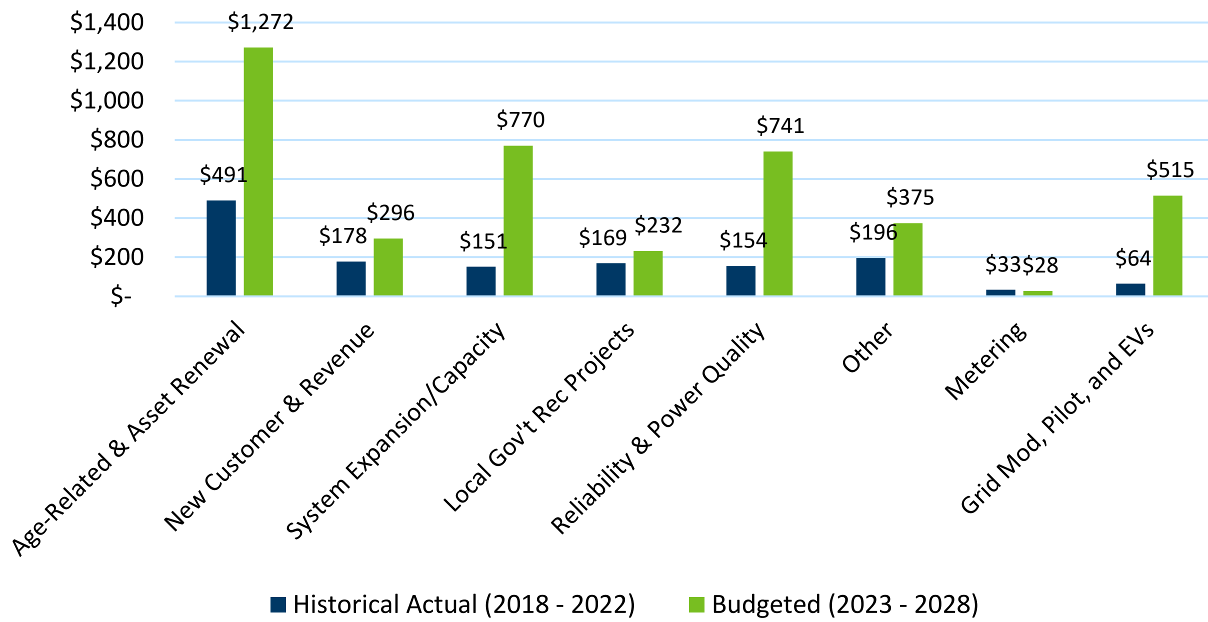


According to this review, the Department found the Company's budget continues to increase above projections each year. The Company's 2021 IDP projected total distribution spending was approximately $3 billion between 2021 and 2026, but compliance filings showed spending increasing between the years 2021-2027 to $3.9 billion. Now, in the 2023 IDP, the Company's

[104] Fresh Energy, Initial Comments, March 1, 2024, p. 10-11
[105] GEC, Initial Comments, March 1, 2024, p. 34
[106] Department, Initial Comments, March 1, 2024, p. 6. Figure created from Table 1

projected total distribution budget between 2023 and 2028 is $4.2 billion.[107] The Department notes primary budget category increasers are the Age-Related Replacement and Asset Renewal category, the System Expansion or Upgrades for Capacity category, and the System Expansion or Upgrades for Reliability and Power Quality category. Figure 12 depicts historic actual spending vs future projected spending across the IDP categories.

Figure 12: Comparison of Distribution System Spending Reported in Xcel's 2023 IDP, Historical Actual (2018–2022) vs. Budgeted (2023–2028)[108]



After review of this budget increase, the Department expressed concern over the limited visibility the Department has into the Company's total budget. Specifically, the Department expressed concern over the Company's lack of specificity on projects and programs in IDP budget category allocations. In the Age-Related Replacements and Asset Renewal spending category, the Company allocates funds according to blanket costs, program costs, and project costs. Such program and project are scattered throughout the IDP, but the Company does not provide specific differences between these spending categories. The Company also allocates over $700 million in the Company's System Expansion or Upgrades for Reliability and Power Quality budget category and $500 million of that budget was identified it as "All Other Programs." Due to the Company's broad language that covers large spending allocations, the Department recommends Xcel be required to separate its total budget into discrete, specific categories that increases transparency of the distribution budget.[109]

Next, the Department addresses the potential to align distribution spending with forthcoming rate cases. The Department shares the interest with other parties to have consistent comparison between budgets presented in IDP filings and cost recovery proceedings. In Xcel's

[107] Department, Initial Comments, March 1, 2024, p. 5-6
[108] Department, Initial Comments, March 1, 2024, p. 9. Figure created from Table 3
[109] Department, Initial Comments, March 1, 2024, p. 5-14

2023 IDP filing, it advocated for the removal of the IDP-specific budget categories as the Company notes the manual work required to translate its capital budget from its internal categories into the IDP-specific categories. Simply, translating budget information into IDP budget categories for the IDP filing is time and resource intensive for the Company and the Company proposes to present the financial information in a manner consistent with other dockets, including cost recovery proceeding. The Department is generally supportive of Xcel's proposed modifications to the IDP Filing Requirements to improve efficiency and consistency.[110]

iv. Xcel Energy – Reply Comments

In this section, the Company responds to questions regarding the IDP Budget Categories, the request for additional non-traditional IDP priorities, and additional metrics to evaluate cost effectiveness of capacity projects.

First, the Company responds to the Department's question on whether Age-Related Replacements and Asset Renewal budget includes capacity expansion benefits. The Company provided that some projects may have this benefit, but projects with that intended benefit are found in the Capacity budget category.

In response to Fresh Energy's request on why the Company's budget for System Expansion or Upgrades for Capacity increased, the Company provided that the increase is due to proactive grid upgrades and grid enforcement expenditures, and not due to a change in the number of risks. Xcel clarified that its risk analysis does not identify every feeder or substation that exceeds the new 75% loading capacity. It also explained that "the change in threshold does not impact the quantity of risks – it only impacts the quantity and magnitude of mitigations to address those risks… it is not expected that the quantity of risks would significantly change due to the change in threshold; only the number of projects that need to be funded in the budget would increase."[111]

The Company responded to GEC who requested hosting capacity and equity be incorporated into the Company's IDP planning objectives. The Company stated that hosting capacity and equity are two non-traditional goals and incorporating them into the IDP planning priorities would be resource intensive and it may be more effective to treat these goals as separate categories with their own prioritization criteria for feasibility, cost, and benefits.[112]

Lastly, in response to the Department's request for feed as to the feasibility of providing additional metrics to evaluate the cost-effectiveness of capacity projects, the Company thinks additional metrics are not needed. The goal of capacity projects is to maintain reliability, and the project risk score is the measure the Company uses to prioritize which projects to plan. Therefore, the Company does not support any additional metrics to evaluate cost effectiveness of capacity projects.

---

[110] Department, Initial Comments, March 1, 2024, p. 17
[111] Xcel Energy, Reply Comments, March 22, 2024, p. 37-38
[112] Xcel Energy, Reply Comments, March 22, 2024, p. 37-39

v. GEC – Reply Comments

GEC disagreed with Xcel's characterization of isolating hosting capacity and equity as "non-traditional" goals. GEC explained that "by isolating equity and hosting capacity objectives from its traditional objectives, Xcel implies that more traditional investments cannot also result in improvements to equity or hosting capacity." GEC noted that this approach could lead to more inefficient upgrades on the grid, as when Xcel is making a reliability improvement there are also likely increases to available hosting capacity. GEC acknowledged that changing the existing distribution budget process may be challenging and require additional company resources, but it would advance equity and Energy Justice. GEC also emphasized that they are not recommending prioritizing hosting capacity and equity above other goals, but rather that they are part of the consideration.[113] (**Decision Option 24**) GEC also requested the Commission reaffirm that it will rely on the IDP when reviewing utility distribution investments in rate cases, and that if a rate case proposal is inconsistent with the utility's IDP, then the bar for Commission approval is significantly higher. (**Decision Option 25**)

vi. CEEM – Reply Comments

CEEM requests the Commission require Xcel to (1) address impacts from rate design changes on its IDP forecasts and the effect of those changes on its investment planning, (2) incorporate load flexibility programs in its forecasts along with greater particularity, (3) explain whether energy storage was considered by Xcel as a means by which to address present or future solar DER capacity constrained feeders, and (4) quantify the number, scale and types of DER projects it expects to support with the hosting capacity placeholder.[114]

vii. Department – Reply Comments

In response to the Department's initial recommendations, the Company did not address many of the Department's concerns regarding the budgeting process. The Department reiterates its intention behind the initial recommendation was to provide greater transparency for stakeholder and the Commission review. The Department does not believe the Company's filed IDP contains sufficient information for external review. The Department maintains its initial recommendations that the Commission require Xcel to provide the following information for transparency and information sharing:[115]

1. Provide increased detail about distribution grid projects in addition to the more aggregated budgets provided in the IDP. (**Decision Option 26**)
2. Quantify the benefits associated with investments in capacity expansion (metrics) and other distribution program budgets. (**Decision Options 31 and 32**)
3. Eliminate its use of IDP-specific budget categories in favor of Xcel's rate case budget categories. (**Decision Option 14**)

113 GEC, Reply Comments, April 12, 2024, p. 19-20
114 CEEM, Reply Comment, April 12, 2024, p. 5
115 Department, Reply Comments, April 12, 2024, p. 6

viii. Staff Analysis

Staff shares the concern with stakeholders about the increases in Xcel's distribution budget. While it is likely that investments will be above historic levels, the scale at which investments are increasing is a cause for concern given the rate impacts of increased distribution spending. While the IDP is not a prudency review of Xcel's distribution budget, it is a chance for the Commission to examine the spending levels and give guidance to the Company.

First, Staff notes there appears to be a disconnect between Xcel's current "budget" forecast used to plan its distribution system spending and the justification the Company gives for increases in several budget categories. Overall, the Company attributes spending increases to the need to prepare the grid for electrification, however the corporate load forecast depicted in Figure 5 indicates a decline in overall load during the 10-year planning horizon. Staff confirmed with Xcel that the budgets in the IDP are based only on the "Budget Plan" scenario which does not include any forecasted electrification.[116] The Commission may wish to clarify with Xcel how it plans to incorporate electrification forecast into its budget planning and indicate to the Company that if it plans to increase distribution budget categories because of forecasted load growth, it will need to justify those investments with forecast data in a rate case.

Staff appreciates Fresh Energy's attention to the planned change in Xcel's feeder loading standard from 106% of equipment rating to 75%. Again, if this change is related to electrification and load increases, Staff would like to know more about how this change will impact the budget and planned upgrades, especially how this would overlap with the Company's plans to conduct proactive upgrades for electrification under the Grid Reinforcement Program.

In conclusion, Staff appreciates that the Company is prospectively looking to changes in load and customer preferences when making distribution investments, however it is not clear how these changes are justified and incorporated into the budget planning process and how much overlap there is between different policies and individual budget categories. As Xcel looks ahead to its next rate case and the next IDP, Staff believes it should focus on a comprehensive explanation of how it plans the budget, investments, and forecasts to align with each other.

A. Cost Benefit Analysis for Discretionary Investments

In its July 17, 2023 Order in Xcel's last rate case, the Commission required the Company to evaluate "the feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget" in response to concerns about the overall size and increase of Xcel's Asset Health and Reliability Budget.[117]

In its IDP filing, Xcel noted there is no universal methodology for cost benefit analysis, however each tends to follow five similar steps: 1. Identify Project Scope, 2. Determine Costs, 3. Determine Benefits, 4. Compute Analysis Calculations, 5. Make Recommendation and Implement. Based on this process, the Company explained that what is currently calls a "risk

[116] Ex Parte Communication, February 21, 2024

[117] This budget category largely overlaps with the Age Related and Asset Renewal IDP budget category.

analysis" is in fact a cost benefit analysis for its major capacity projects. Similarly, the NWA process is also a cost-benefit analysis.[118]

Xcel noted that conducting individual cost benefit analysis for each discretionary project was not an efficient use of time or money, however, it did believe that "strategically applying CBAs to program level investments would be valuable and will work towards evaluating and developing an approach to do so."[119]

i. Fresh Energy – Initial Comments

Fresh Energy emphasized the importance of conducting program level cost benefit analysis for discretionary distribution system investments. Fresh Energy pointed to a recent report by the Regulatory Assistance Project that stated:

> Historically, utilities have relied on least cost/best fit (LCBF) techniques to make decisions about investments in utility-owned infrastructure ... After the utility identifies something that is needed to maintain safe and reliable electric service or extend service to a new area, it then seeks the least costly way to meet the identified need in a manner that complies with all applicable legal requirements …
>
> In contrast, we apply the term 'benefit-cost analysis' to methods that compare the costs and benefits of investment alternatives to assess and maximize the net benefits (i.e., benefits minus costs) when viewed from an agreed perspective. This can include situations where the options being considered include the status quo or a 'take no action' alternative ... Benefit-cost analysis techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods.[120]

Fresh Energy agreed with Xcel that it is not feasible to conduct a CBA for each individual discretionary project, and recommended Commission require the Company to conduct a CBA on six categories within its Asset Health and Reliability budget that total $1.26 billion from 2024-2028, or approximately 34% of Xcel's total distribution capital budget:

- Substation Renewal Programs ($161 million budget from 2024-2028)
- Line Renewal Programs
    - Network Renewal ($34 million)
    - Line Equipment Renewal ($517 million)
    - Pole Related Renewal ($203 million)
- Proactive Asset Health - Discrete Projects ($137 million)
- Cable Replacement Program ($207 million)[121]

Fresh Energy pushed back on Xcel's implication that it cannot quantify risk for asset health and reliability programs, stating that the Company already quantify risks in many ways, for example

[118] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 24 (PDF p. 42)
[119] Xcel Energy, 2023 IDP Part 1 of 3, November 1, 2023, p. 24-25 (PDF p. 42-43)
[120] Shenot, J., Prause, E., & Shipley, J. (2022). *Using Benefit-cost Analysis to Improve Distribution System Investment Decisions: Issue Brief*. Regulatory Assistance Project.
[121] Fresh Energy, Initial Comments, March 1, 2024, p. 23-24

by evaluating end of useful life, historic failure rates, and asset criticality. According to Fresh Energy, this can form the basis of a CBA.[122]

ii. GEC – Initial Comments

GEC strongly supported requiring CBA for discretionary distribution system investments where possible. GEC noted that while Xcel had raised a concern about lack of consensus on issues like the definition of "discretionary" and what to include in a CBA methodology, it believed "Xcel has missed an opportunity to address them more thoroughly in this IDP, including by putting forth constructive proposals for party feedback." GEC agreed with Fresh Energy that the Commission's Order directed Xcel to consider CBA for larger budget or program categories, and not individual discrete projects.[123] Therefore, GEC recommended the following decision options:

- Clarify that Xcel should evaluate applying cost-benefit analyses to program-level investments. (**Decision Option 30**)
- As part of the above effort, require Xcel to explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.[124] (**Decision Option 29**)

iii. Minneapolis – Initial Comments

Minneapolis supports requiring a cost-benefit analysis for discretionary distribution system investments believing CBA to be a "useful tool for comprehensively evaluating investments as the grid system becomes more complex."[125] (**Decision Option 30**)

iv. Xcel Energy – Reply Comments

In reply comments Xcel reiterated that CBA for individual projects was impractical and costly, and outlined reasons why it was unnecessary to conduct them for different budget categories. For capacity projects Xcel indicated it already uses a risk scoring methodology to evaluate and prioritize Capacity projects which includes the consideration of factors such as a discount rates, tax rates, inflation rates, and SAIDI data to calculate a benefit-cost ratio.[126] Similarly, the Company explained it creates risk scores for Asset Health and Reliability projects based on historical outage data, however Xcel noted a CBA would not be appropriate as it does not include "qualitative benefits or intangible factors" that often foster disagreement among stakeholders.[127]

Therefore, the Company stated that it opposed a requirement to conduct CBAs for discretionary projects, and the six categories of projects recommended by Fresh Energy. However, Xcel indicated it was open to stakeholder discussion and ""having additional

---

[122] Fresh Energy, Initial Comments, March 1, 2024, p. 24
[123] GEC, Initial Comments, March 1, 2024, p. 48
[124] GEC, Initial Comments, March 1, 2024, p. 4
[125] Minneapolis, Initial Comments, March 1, 2024, p. 4
[126] Xcel Energy, Reply Comments, March 22, 2024, p. 27
[127] Xcel Energy, Reply Comments, March 22, 2024, p. 28

conversations on approaches for applying CBAs, or a similar type of evaluation, strategically to program-level investments."[128] (**Decision Option 27**)

v. Fresh Energy – Reply Comments

In reply comments Fresh Energy emphasized the scale at which Xcel's distribution budget is increasing:

> Increased distribution spending is a trend occurring across the country, but that does not mean it does not deserve scrutiny. These increases create upward pressure on electric rates and affordability, at the same time that Minnesota policy requires electrification of more of our lives. Fresh Energy believes transparency into the customer benefits from this increased spending (especially the discretionary portions of it) is critical, and CBAs can provide an important measure of transparency.

Fresh Energy appreciated the Company's offer to continue to work with stakeholders on CBA, and recommended the Commission accept the Xcel's proposal and direct it to report on the discussions in the next IDP.[129] (**Decision Options 27 and 28**)

vi. GEC – Reply Comments

GEC supported Xcel collaborating with stakeholders to work to develop CBAs for discretionary investments and continued to recommend **Decision Options 27** and **28**.[130]

vii. Department – Reply Comments

In reply comments the Department explained that in initial comments it had chosen "to focus on the Company's obligation to provide CBAs for its planned grid modernization projects" instead of evaluating whether Xcel should provide a cost benefit analysis for discretionary investments. However, after reading responses, the Department clarified that Xcel should provide "detailed cost and benefit information about its elective distribution investments irrespective of whether they are "modernization" projects." The Department provided a list of recommended metrics to evaluate elective distribution grid investments and recommended the Commission "direct Xcel to provide a proposal for reporting on the expected benefits and costs of elective distribution grid investments in its next IDP." (**Decision Option 31 and 32**)

viii. CEEM – Reply Comments

CEEM respectfully requests the Commission to (1) require Xcel to explain "discretionary" spending as well as its methodology for determining cost-benefit and (2) clarify Xcel should apply the cost-benefit analysis to program investments.[131] (**Decision Options 29 and 30**)

ix. Staff Analysis

Capital distribution investments are generally categorized into two categories: reactive and proactive/discretionary. Reactive investments are in response to an immediate need, such as a

---

[128] Xcel Energy, Reply Comments, March 22, 2024, p. 29
[129] Fresh Energy, Reply Comments, April 12, 2024, p. 8-9
[130] GEC, Reply Comments, April 12, 2024, p. 25
[131] CEEM, Reply Comments, April 12, 2024, p.8

pole failure during a severe storm or a capacity upgrade to serve imminent new construction. Proactive, or discretionary investments are not made in response to any urgent threat, instead they are done before equipment failure or capacity need to prevent an outage or last-minute upgrade. A utility's discretionary investments are an important part of ensuring the system is reliable, resilient, and response to customer needs. However, they must also be carefully considered to ensure they are going where they can have the most impact on key indicators and that spending remains within appropriate levels to prevent unwarranted costs to customers. Additionally, it is also important to ensure discretionary investments are being allocated equitably throughout service territory. As noted above, Xcel's discretionary distribution budgets are rapidly increasing. In the six categories identified by Fresh Energy, the budgets are increasing by over 7,000% percent over the 2018-2022 average.[132] Table 7 depicts the percent increase over the historic average for the six budget categories noted by Fresh Energy:

Table 7: Increase in Selected Distribution Programs ($M)

	2018-2022 average	2024	2025	2026	2027	2028	**Total 2024-2028**
Substation Renewal Programs	$5.9	$19.9	$24.3	$35.3	$39.7	$41.6	**$160.7**
% change		*235%*	*309%*	*494%*	*569%*	*600%*	
Network Renewal	$1.8	$7.0	$7.3	$7.5	$7.8	$3.9	**$33.5**
% change		*287%*	*301%*	*310%*	*327%*	*117%*	
Line Equipment Renewal	$3.9	$8.8	$23.8	$39.9	$159.9	$284.4	**$516.7**
% change		*125%*	*511%*	*924%*	*4,003%*	*7,199%*	
Pole Related Renewal	-	$0.5	$22.6	$37.8	$69.3	$72.7	**$202.9**
% change							
Proactive Asset Health – Discrete Projects	$10.9	$42.6	$25.0	$21.9	$16.6	$30.8	**$136.9**
% change		*292%*	*130%*	*102%*	*53%*	*184%*	
Reliability – Cable Replacement	$25.7	$36.0	$38.4	$41.4	$44.3	$46.6	**$206.7**
% change		*40%*	*49%*	*61%*	*72%*	*81%*	
Total	**$48.2**	**$114.8**	**$141.5**	**$183.7**	**$337.6**	**$480.0**	**$1,257.5**
% change		***138%***	***193%***	***281%***	***600%***	***895%***	

Staff agrees that further conversations between stakeholders and Xcel are an appropriate path forward at this time and supports **Decision Options 27** and **28**. That said, Staff notes the discussions on CBA are unlikely to be done in time for Xcel to incorporate any results into a rate case filing if it chooses to file one on November 1 of this year. The Company's current multi-

[132] One category, Pole Related Renewal, is a new category in the forecasted budget.

year rate plan runs through the end of 2024. Given the significant increases in budget categories demonstrated in this IDP, the Commission may wish to consider encouraging the Company to include additional justifications and information on the programs identified by Fresh Energy.

Staff discusses the Department's proposal for Xcel to create metrics for elective distribution investments in the Joint Briefing Papers.

- **Decision Options 31** and **32** adopts the Department's recommendation
- **Decision Option 33** adopts Staff's recommendation

B. Proactive Grid Upgrades and Cost Allocation

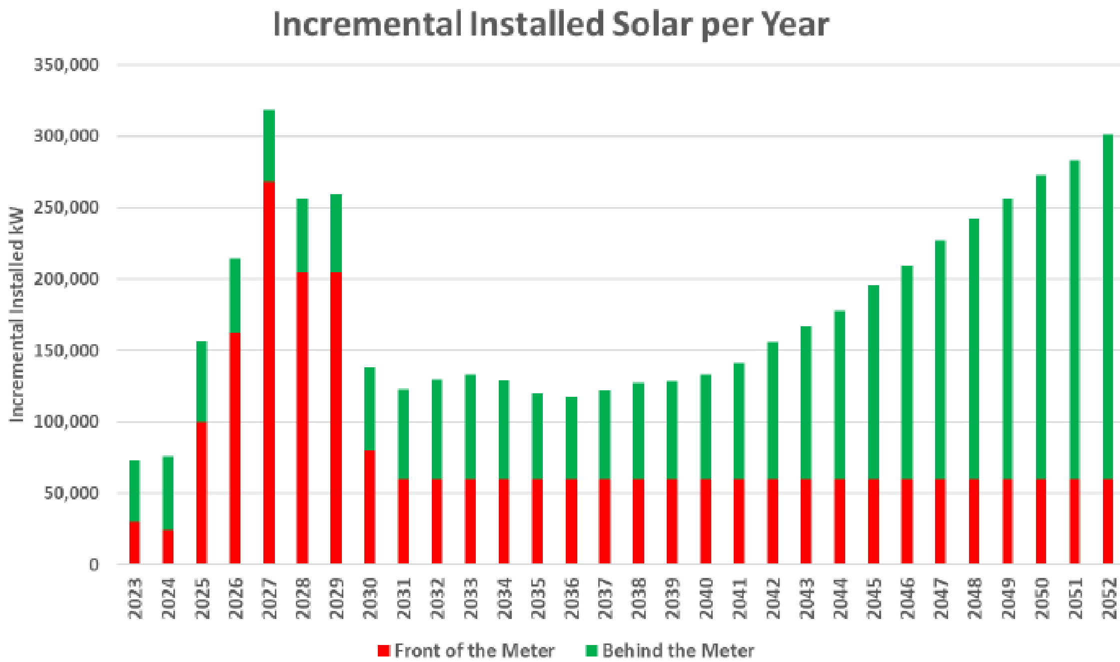
As indicated in its load forecast, Xcel is anticipating large additions of distributed generation, electrification, and other distributed energy resources over the next 30 years. As part of its 2023 IDP, Xcel forecasted the needed capacity upgrades for its predicted Front of the Meter (FTM) and Behind the Meter (BTM) DER adoption over the 2023-2052 period as well as the forecasted costs for the respective upgrades to better assess how to incorporate additional distributed generation.

<u>Methodology</u>

To create its forecast for distribution system upgrades Xcel used the location-specific LoadSEER forecast data from the IDP High scenario of the solar PV adoption forecast which uses BTM and FTM forecasts.[133] The FTM forecast accounted for large amounts of solar due to changes in state energy policy, including 500 MW of solar required to meet the Distributed Solar Energy Standard (DSES) over the 2026-2029 timespan and that the new CSG program will reach its annual cap each year. Xcel offers the following figure, forecasting the incremental FTM and BTM solar installed onto the distribution system:[134]

[133] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 2, (PDF p. 192)
[134] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 3, (PDF p. 193)

Figure 13: Forecasted Solar Allocated to the Distribution System



Xcel uses this data from LoadSEER, "which produces a forecast, by year and by feeder, of the amount of nameplate solar PV generation that was allocated to specific locations on the distribution system" in order to find which feeders will require capacity upgrades.[135] The amount of kW that exceed Xcel's Technical Planning Standard (TPS) on these feeders was then multiplied by the marginal cost of distribution capacity in order to determine the total cost of the upgrade on that feeder. The marginal cost of distribution capacity used in this study is $320/KW and is what the Company used in its most recent VOS filing in Docket No. E002/M-13-867. The value uses the average of the costs from the prior two years, the current year, and the forecasted two years. Xcel believed that significant incremental DER adoption will likely also cause constraint in some parts of the transmission system that will need mitigation. These forecasted upgrade costs, including a two percent cost escalation rate to account for increased cost is how Xcel determined its capacity expansion budget for generation. The upgrade costs also account for the TPS.

Results

Xcel split the costs into two components – component one is to get all existing feeders and feeders with projects in-queue in compliance with the TPS, and component two includes all forecasted costs in the 30-year horizon that is not included in the TPS compliance component. Xcel stated that it expects it will cost $47.7 Million to get its existing feeders TPS-compliant.[136] Xcel explained that that an upgrade of this type can look like a feeder with a TPS limit of 10 MW with 12 MW of already installed and in-queue PV getting upgraded to have a TPS limit of 12 MW.

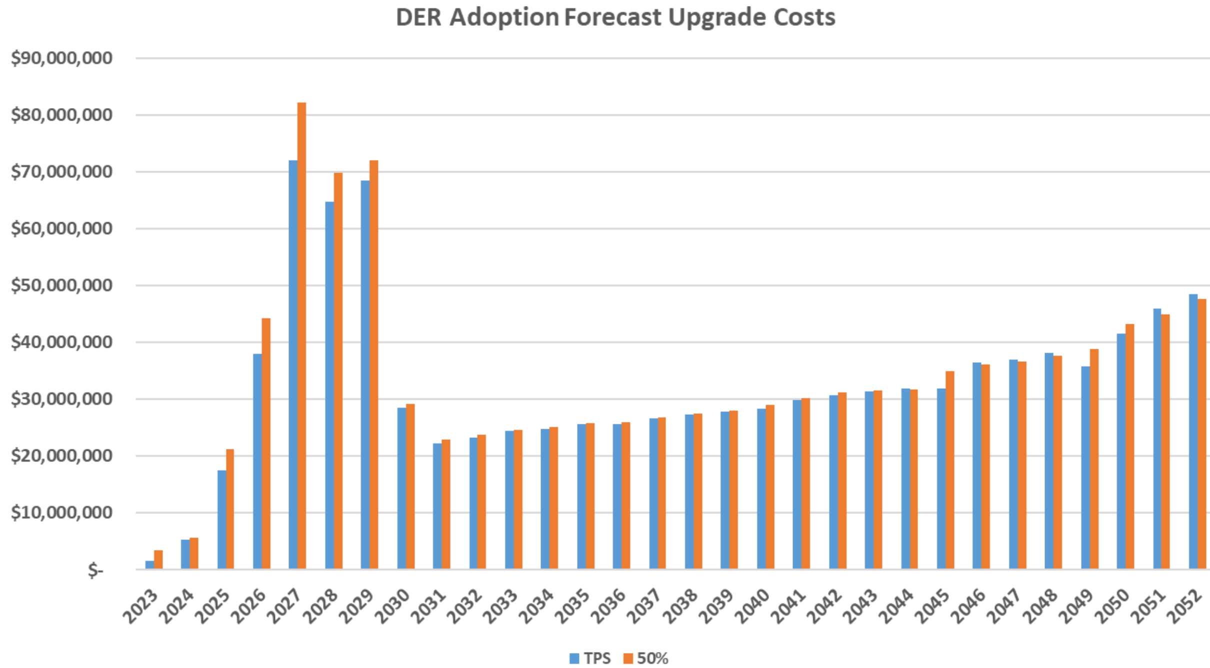
---

[135] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 3, (PDF p. 193)
[136] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 5, (PDF p. 195)

Xcel also forecasted the costs assuming a different TPS formula where the Equipment Rating was increased to 100%, and 50% of the available capacity was reserved for small DERs (40 kW and under) but the Daytime Minimum Load (DML) was removed from the formula. The Commission denied this change through its April 15, 2024 Order in Docket NO. E-999/CI-16-521.

Xcel forecasted the annual upgrade costs from 2023-2052 as follows:[137]

Figure 14: Forecast of Upgrade Costs 2023-2052, for TPS and 50% Planning Limit Scenarios



Staff notes that the 50% TPS, or the orange section in the above Figure 14, is an alternative TPS that Commission has denied so Staff recommends focus be placed only on the blue bars of the graph.

The culmination of the forecasted upgrade costs is summed in Tabled 8:[138]

Table 8: Summary of Upgrade Cost Components

Planning Limit Scenario	Existing Constraint Cost	2023-2052 Forecast Cost	Total 30-Year Cost
Current TPS	$47.7M	$992.2M	$1,039.9M

Measures to Reduce Need for or Cost of Distribution Upgrade

Xcel listed Smart Inverters, Grid Management Tools, DER Management Tools, and Energy Export Tariffs as measures that are applying downward pressure on distribution upgrade costs. Xcel has begun (and has been required to use as of January 1, 2024) advanced smart inverters and their settings included Volt-Var and Volt-Watt controls both of which help with voltage control. Advanced Distribution Management System (ADMS) is the Company's main grid

[137] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 6, (PDF p. 196)
[138] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 5, (PDF p. 195)

management tool which Xcel stated provides "enhanced information when using engineering judgement and when evaluating on a case-by-case basis whether it is safe for DER to operate in an alternate configuration that would otherwise require disconnection or system upgrades to operate" as well as voltage optimization potential.[139] Xcel stated that a distributed energy resource management system (DERMS) approach to control DER under a flexible interconnection agreement to reduce the need for or cost of system upgrades.

Alternate Cost Allocation Methods

Xcel discussed four different cost allocation methods that have emerged in the industry that may be appropriate for Xcel Energy and Minnesota. Xcel stated they are open to feedback on these alternatives and understand that each method may require specific changes to the Minnesota Distributed Energy Resources Interconnection Process (MN DIP), Distributed Energy Resources Interconnection (MN DIA), and / or the Company's tariffs.[140]

Retroactive Cost Sharing Between DG Facilities

This cost allocation method would have the triggering project pay for the entire upgrade up front to the utility and the utility would then provide the project company with "true-up" payments collected from subsequently interconnected facilities that take advantage of the freed-up capacity. Xcel stated that this method would be burdensome on the triggering project as there would be no guarantee whether or when subsequent projects would seek to interconnect and share the cost. The Company also stated that it would be administratively burdensome to facilitate.[141]

Prospective, Location-Specific Cost Sharing Between DG Facilities ("Cost Sharing 2.0")

This method has utilities determine the per-kW cost of upgrades which would then be applied to each DG facility interconnecting to that portion of the system based upon the facility's nameplate capacity. Xcel states that the portions of the system targeted for upgrades can be identified by either the utility for future expansion needs or pending requests for interconnection. The Company believes this would give DG owners and developers more certainty but would be "very administratively burdensome and costly – costs that would need to be included in the per-kW upgrade costs."[142]

Costs of Interconnection Paid by the Utility and Recovered from All Customers

This method would rate base all interconnection upgrade costs, meaning that it would no longer be a "cost-causer pays" method and Xcel would be able to make a return on the investment. Xcel states that some argue the broader public policy benefits of DG means that all customers should bear the cost of interconnection and points to the $10 million that was

[139] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 9, (PDF p. 199)
[140] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 12-13, (PDF p. 202)
[141] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 12, (PDF p. 202)
[142] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 12-13, (PDF p. 202-203)

granted to the hosting capacity upgrades for small DER projects in the 2023 legislature under the Distributed Energy Resources System Upgrade Plan.[143]

Network Upgrade/System Enhancement Credits

This approach would recognize that network upgrades can be a common benefit to interconnecting projects as well as the surrounding customers and facilities and costs can be shared between them. Xcel states this is a “hybrid wherein the utility analyzes the potential broader benefits of network upgrades and costs are shared if benefits are identified” and “may reduce developers’ costs and motivate developers to site projects most efficiently.” However, Xcel states this would take time to develop, as well as the needed tools, human resources, and agreements between customers and developers that there are common benefits to the upgrades.[144]

i. GEC – Initial Comments

GEC encouraged the Commission to embrace a holistic vision for the future grid when considering grid upgrades and cost allocation that incorporates energy justice and equitable distribution of budgets to mitigate past harms imposed by the electric system.[145] In examining Xcel’s distribution budget GEC noticed that three largest areas of projected spending for the Company could result in increased hosting capacity for DERs. Therefore, GEC explained that categorizing “upgrades to enable DERs” as a separate budget item may not be necessary as upgrading equipment at the end of its life could also include an upgrade to increase hosting capacity. GEC encouraged Xcel to include increased hosting capacity as an additional consideration when assessing budget planning.[146]

In regard to determining fair cost allocation for proactive upgrades, GECs suggested the Commission consider non-energy benefits and socializing costs across all ratepayers if it is difficult to attribute specific costs and benefits to individual customers or groups. It also explained that it will be necessary to move beyond the traditional “cost-causer pays” model for DER upgrades.[147] The GECs supported including a specific budget line item for proactive upgrades in addition to incorporating hosting capacity into other budget prioritizations. They encouraged paying attention to cost allocation and recovery when looking at proactive upgrades, as well as how the utility justifies and prioritizes which areas receive upgrades. GEC concluded that residential and small commercial customers should be prioritized for proactive hosting capacity upgrades given they 1) do not historically bear capacity costs for load upgrades, meaning existing cost recovery mechanisms can be reused and 2) forecasting for their specific customer segments is more reliable than forecasting for large commercial or industrial customers.[148] GEC urged the Commission to avoid letting large customers take advantage of any proactive hosting capacity upgrades. GEC noted Xcel has proposed a Grid

---

[143] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 13, (PDF p. 203)
[144] Xcel Energy, 2023 IDP Part 3 of 3, Appendix I, November 1, 2023 p. 13-14, (PDF p. 203-204)
[145] GEC, Initial Comments, March 1, 2024, p. 40
[146] GEC, Initial Comments, March 1, 2024, p. 40-41
[147] GEC, Initial Comments, March 1, 2024, p. 41-42
[148] GEC, Initial Comments, March 1, 2024, p. 43-44

Reinforcement Program to upgrade congested areas of the grid for electrification and recommended the Commission require Xcel to report on actual upgrades in future IDPs to evaluate deployment.[149] (**Decision Option 36**)

In regard to Xcel's proposed $190 million budget for proactive hosting capacity upgrades, GEC supported using the funds for areas that primarily serve residential and small commercial customers, while prioritizing energy justice and underserved communities for upgrades. GEC emphasized that any proactive upgrade costs that are socialized to all ratepayers should prioritize maximizing the benefits of DERs.[150] (**Decision Options 37 and 38**)

ii. Fresh Energy – Initial Comments

Fresh Energy proposed a series of framing questions for starting a discussion on proactive upgrades:

1. What are the problems we are trying to solve through proactive upgrades? In which customer classes and technology areas is adoption being hampered by the status quo / lack of proactive upgrades?
    a. Can these problems be solved through improving the efficiency and speed of the current process?
    b. Can these problems be solved by adjusting cost allocation for non-proactive upgrades? Would doing so be reasonable and equitable?
2. Would proactive upgrades improve operating efficiency, reduce truck rolls, or provide other benefits?
3. Are there no-regrets ways to plan for DER and electrification in the baseline load forecast, and therefore accomplish proactive upgrades via distribution planning?
    a. For which customer and technology segments do grid upgrades pay for themselves/ have a net revenue requirement benefit for ratepayers?
    b. How locationally and temporally accurate are Xcel's LoadSEER forecasts for each technology type? How accurate do they need to be to ensure a net beneficial result?
4. Are there customer and technology segments for which it may make sense to perform proactive upgrades that are paid back (on a prorated basis) over time by future interconnecting customers?

Fresh Energy also noted it is important to distinguish between cost allocation and proactive upgrades, which are often conflated in conversations about grid upgrades for DERs. It offered a matrix to explain the different options available, along with risks and benefits.

[149] GEC, Initial Comments, March 1, 2024, p. 44-45
[150] GEC, Initial Comments, March 1, 2024, p. 45

Table 9: Cost Allocation and Proactive Upgrade Matrix[151]

	Proactive Upgrades	Reactive Upgrades
Shared Cost Allocation	• Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case. • Benefits customers adopting DER and electrification by reducing or eliminating wait time and cost of interconnection. • Risks include deploying assets that are not used and useful if forecasts are not accurate, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.	• Grid upgrades are made in response to individual customer requests. • Costs assigned via typical class cost allocation methods, e.g., in the next rate case. • Benefits customers adopting DER and electrification by eliminating the cost of interconnection; benefits ratepayers by ensuring upgrades are used and useful. • Risks include continued wait-times in the interconnection process, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.
Individually Allocated Costs	• Build distribution budgets around DER and electrification forecasts. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection. • Benefits customers adopting DER and electrification by reducing or eliminating wait times for interconnection; benefits ratepayers by reducing the costs of upgrades via reimbursement over time. • Risks include deploying assets that are not used and useful if forecasts are not accurate, and the potential for shifting costs of upgrades onto non-benefitting customers if forecasts or reimbursement fees are not accurate.	• Grid upgrades are made in response to individual customer requests. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection. • For the most part the model in place today • Benefit is ensuring upgrades are used and useful. • Risks include wait time and interconnection costs for DER and electrification customers.

Fresh Energy explained that the optimal combination of cost allocation or proactive upgrades may depend on the customer group and technology type, as the different characteristics of these segments and different policy objectives will play a role in what is in the public interest.[152]

For proactive upgrades, Fresh Energy outlined the following principles it believed any investment should meet in order to be in the public interest:

---

[151] Fresh Energy, Initial Comments, March 1, 2024, Table 3, p. 17-18. Staff included risks and benefits from the following paragraph in the matrix.

[152] Fresh Energy, Initial Comments, March 1, 2024, p. 18

1. **Useful**: Proactive upgrades should be located in a relevant spot, needed, and useful.
2. **Timely**: Proactive upgrades should be reasonably certain of being useful within a specified period of time.
3. **Efficient**: Proactive upgrades that are recovered in base rates should be paired with programs that require or encourage efficient use of the grid (such as charging/discharging at preferable times to maximize utility of the infrastructure.)
4. **Equitable**: The costs and benefits of proactive upgrades should be equitably distributed, and any upgrades recovered in base rates should prioritize projects serving under-resourced customers or under-served areas of the system.[153]

In regard to the $190 million placeholder budget for proactive upgrades, Fresh Energy recommended it not move forward until greater details about the implementation of the funds are available so the Commission can assess whether it is in the public interest, using the principles outlined above.[154] Fresh Energy also noted that it would be useful for the Commission and stakeholders to have a better idea of the geographic distribution of forecasted DER and electrification that Xcel has forecasted in LoadSEER, including whether technology specific forecasts could be displayed on a map[155]

Fresh Energy stated additional record development was needed to create an approach to proactive and cost-shared upgrades for DERs and electrification, either through a docketed process or a Commission led workshop and sought input from other parties on preferred pathways.[156]

iii. Department – Initial Comments

The Department emphasized the importance of right-sizing any proactive upgrades to avoid upward pressure on rates.[157] It also pointed out that with the large increase in Xcel's distribution budget, there are opportunities to make capacity upgrades when making asset health and reliability infrastructure decisions.[158] Responding to Xcel's various cost allocation scenarios, the Department pointed to the existing small solar cost sharing pilot for projects under 40kW and recommended that Xcel be required to "provide options, if any, to help distribute costs to interconnect a small residential facility on a saturated feeder including whether a flat interconnection fee, similar to the small solar array fee, has been considered for larger facilities."[159] (**Decision Option 39**)

While the Department acknowledged Xcel had indicated the $190 million for proactive upgrades was a budget placeholder, it still expressed concern about the lack of analysis used to construct the initial estimate for upgrades. Therefore, the Department recommended directing Xcel to provide additional information about how many projects the funding would support,

[153] Fresh Energy, Initial Comments, March 1, 2024, p. 19
[154] Fresh Energy, Initial Comments, March 1, 2024, p. 19
[155] Fresh Energy, Initial Comments, March 1, 2024, p. 20-21
[156] Fresh Energy, Initial Comments, March 1, 2024, p. 21
[157] Department, Initial Comments, March 1, 2024, p. 18
[158] Department, Initial Comments, March 1, 2024, p. 19
[159] Department, Initial Comments, March 1, 2024, p. 24

how much DER those projects would enable, and what percent of the Company's forecasted DER the budget would address.[160]

iv. Minneapolis – Initial Comments

Minneapolis stated that in general it believed that "cost allocation for interconnection and electrification should not fall 100 percent on the customer" and that costs should be "pro-rated to reflect the years in service and subtract costs already recovered for equipment being replaced."[161] Minneapolis continued emphasizing that some equipment may already be near the end of its life when it's replaced which should be accounted for and replaced equipment can sometimes be deployed elsewhere.

v. Xcel Energy – Reply Comments

Xcel appreciated the variety of feedback about proactive upgrades and cost allocation for DERs. The Company agreed with Fresh Energy that further record development is necessary before determining how to select projects for proactive upgrades. Xcel suggested a two-workshop series, led by the Company, where stakeholders present ideas at the initial meeting and then Xcel would prepare a framework based on stakeholder input and present it at the second meeting. Xcel noted that establishing a hosting capacity carve out for residential solar is an integral part of any future proactive upgrade program. Xcel requested the Commission defer any decisions about proactive upgrades until after the stakeholder process concludes.[162]

vi. GEC – Reply Comments

In reply comments GEC also agreed that additional record development was necessary, however they did not support Xcel leading a stakeholder process and instead recommended either a neutral or Commission staff led working group. GEC also noted that Fresh Energy's framing comments provided a helpful starting point for any discussions.[163]

vii. Fresh Energy – Reply Comments

In reply comments Fresh Energy agreed with Xcel's proposed two-meeting approach to develop the issues of cost allocation and proactive upgrades. It suggested that proposals and slides be made available prior to any workshops for review, and a summary of the proposals, stakeholder questions, and Xcel's own proposal be included in the next IDP. Fresh Energy also noted that given the large, forecasted load from beneficial electrification and ongoing discussion about waivers for CIAC for managed residential EV charging it may be necessary to include a broader conversation about CIAC waivers as a part of the conversation.[164] (**Decision Option 35**)

---

[160] Department, Initial Comments, March 1, 2024, p. 30
[161] Minneapolis, Initial Comments, March 1, 2024, p. 3
[162] Xcel Energy, Reply Comments, March 22, 2024, p. 36-37
[163] GEC, Reply Comments, April 12, 2024, p. 22-23
[164] Fresh Energy, Reply Comments, April 12, 2024, p. 7-8

viii. Minneapolis – Reply Comments

Minneapolis also supports Xcel's stakeholder process for cost allocation and proactive upgrades if the engagement is extensive and led by a third-party group like Commission Staff.[165]

ix. Clean Energy Groups – Reply Comments

CEG[166] submitted reply comments supporting additional record development around proactive grid upgrades and cost allocation. It echoed GEC's call for a Commission or neutral third party led process and supported Fresh Energy's framing questions as a starting point for any workshop.[167]

x. CEEM – Reply Comments

CEEM respectfully requests the Commission require Xcel to: (1) report on actual upgrades to its Grid Reinforcement Program so the Commission and stakeholders can evaluate its deployment and (2) explain the scale and scope of DERs it expects to serve with the $190 million placeholder.[168] (**Decision Options 36 and 40**)

xi. Staff Analysis

Staff concurs with Xcel and stakeholders that additional record development is needed prior to devising recommendations and policies for both cost allocation and proactive upgrades for DERs and new load from electrification. Staff also agrees that a focused stakeholder process with concrete goals and outcomes as suggested by Xcel is appropriate to develop the next steps for this topic area. However, as further explained below in the Section 10: Stakeholder Process, Staff believes this should be a Commission-led process that follows the format laid out by Xcel. Staff also believes that having a Commission-run process could also offer the potential to incorporate other utilities in the workgroup if they are interested in participating, and the potential to consider the impacts of new 2024 legislation as discussed below.

Staff offers the following topics to be addressed and goals for the outcome of the process, which is captured in **Decision Option 34**:

- The goal of the workgroup is to develop proposals for proactive upgrades and cost allocation for Commission consideration and possible adoption.
- The process does not need to reach consensus but should aim to clearly identify areas of agreement and disagreement to facilitate a Commission decision.
- The Commission establishes a goal of completing the stakeholder process by [insert date]. At the conclusion of the process there will be a notice and comment period on any proposals followed by a Commission decision.
- Proposals should address, at minimum, the following topics:

---

165 Minneapolis, Reply Comments, April 12, 2024, p. 1

166 Fresh Energy, Union of Concerned Scientists, Sierra Club, and Plug In America, note that Fresh Energy and Sierra Club are each separately submitting additional reply comments concerning the broad set of IDP-related issues.

167 CEG, Reply Comments, April 12, 2024, p. 3-4

168 CEEM, Reply Comment, April 12, 2024, p. 6

- How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory
- How to allocate the costs of proactive upgrades
- If costs are socialized among ratepayers, should certain proportions be reserved for certain customer classes
- How a proactive upgrade program would integrate with Xcel's planned distribution investment programs, including the proposed $190 million for Proactive System Upgrades to Increase Hosting Capacity and $132 million for the Grid Reinforcement Program
- How a utility's other capacity programs and changes to distribution standards impact available hosting capacity
- How to determine where there is a need for proactive upgrades, including using forecasts
- Whether there should be changes to any of a utility's service policy provisions such as contributions in aid of construction (CIAC).

Staff has not set a target date for completion of the workgroup process but suggests the Commission request feedback from participants at the agenda meeting. Staff has included a placeholder for a date.

Staff notes that in 2024 the Minnesota Legislature passed an interconnection bill that addresses cost allocation for large upgrade costs. The Commission must initiate a proceeding to implement the bill by September 1, 2024. While the specifics of the bill will be determined through stakeholder engagement and later by the Commission, the goal of the bill is to work to move away from the current cost allocation method of: cost-cause, single payer, where a single project/developer pays for the entire upgrade that is necessary to interconnect even if the upgrade has costs up to a million dollars which often grants capacity more than that individual project's needs. Instead, this bill would aim to keep the cost causer aspect but rather than have one developer pay for the entire upgrade, several developers can share the costs of the upgrade on a per kilowatt basis.

This cost allocation method for distribution upgrades is meant to be reactive rather than proactive in nature and is essentially a market-based solution to determining when and where upgrades will occur. The bill will require a certain threshold of the total cost of the upgrade to be guaranteed by developers before construction will begin – if there is enough demand from developers, the upgrade will occur, if there is not enough demand for the upgrade, construction will not occur. This solution will hopefully help ameliorate one of the greatest obstacles in capacity constrained areas on the distribution systems – costly upgrades that are too high for individual projects. Staff does not believe the directive to work on this method of cost allocation preempts a simultaneous discussion around proactive upgrades, in fact there could be benefits to discussing the two in tandem.

Finally, as noted above, there are two areas in Xcel's budget where it has included funds for proactive upgrades: $132 million for the Grid Reinforcement Program, which the Company indicated in its prior rate case is to upgrade the grid for new transportation electrification load,[169] and $190 million for the Proactive System Upgrades to Increase Hosting Capacity. Given their inclusion in the 2025-2028 budget forecast, it appears to Staff as though Xcel would include these programs in its next rate case, which could be filed as early as November 1, 2024. Staff suggests it may be helpful for the Commission to indicate to Xcel whether it is appropriate to include these programs in the rate case, given many participants in this docket have indicated it is not reasonable for Xcel to start budgeting for these costs until a comprehensive program for proactive upgrades is designed. Staff believes this is a reasonable position to take, especially given the Commission has previously denied the Grid Reinforcement Program for a lack of specificity and details. If the Commission wishes to adopt this recommendation Staff offers **Decision Option 41**.

C. CIAC Waivers for Electric Vehicle Charging

In the Company's 2021 Rate Case, the Commission ordered Xcel to file tariffs to solidify its informal practice of waiving Contribution In Aid of Construction (CIAC) for electric vehicle customer enrolling in an off-peak charging rate. Xcel filed these tariff changes as part of its 2023 TEP in this docket, however the Office of the Attorney General (OAG) raised concerns that the tariff changes went beyond the scope of what was contemplated in the rate case. In briefing papers Staff noted that the Commission will look at overall issues related to cost-causation principles as part of the broader IDP as part of a discussion around proactive upgrades and cost allocation for DERs. Based on the recommendation of Staff and the OAG and with the agreement of the Department and Xcel, the Commission denied Xcel's tariff modifications without prejudice.[170]

The OAG filed a letter on April 12 continuing to recommend the Commission deny Xcel's proposed tariff changes to CIAC for certain EV customers, stating "while EV-charging load can benefit the system through increased sales revenues, so can any new load. The CIAC tariff already accounts for this benefit by requiring Xcel to analyze the incremental revenue from new load and give the load-adding customer a credit that reduces the customer's CIAC obligation." If, however, the Commission grants Xcel's waiver, the OAG recommended requiring Xcel to "Track the revenues foregone as a result of the waiver so that the impact can be determined and allocated to the appropriate rate classes."[171]

The Clean Energy Groups (CEG) filed reply comments on April 12 reiterating their support for the CIAC waiver, stating that it was already litigated in the rate case, and recommending approval. They also recommended that the Commission "require Xcel collect data on waiver

---

[169] The Commission denied Xcel's capital additions for the Grid Reinforcement Program in its 2021 Rate Case, stating "Xcel has not shown that it duly considered whether managed EV charging or other load-shifting programs could be used to avoid or reduce the need for costly grid upgrades associated with transportation electrification. Nor does Xcel's proposal provide sufficient transparency or detail regarding where the grid reinforcement projects would be done or whether any costs of this program are duplicative of costs accounted for in the Company's routine capacity reinforcements and new business expense categories, which appear to materially overlap with grid reinforcement projects."

[170] May 9, 2024 Order Approving Xcel Energy's 2023 Transportation Electrification Plan with Modifications, Docket 23-452, Ordering Paragraph 9, p. 13

[171] OAG, Letter, April 12, 2024, p. 1-2

amounts and report on those in aggregate as part of the Company's regular data report filings."[172]

On June 12, 2024 Xcel filed a letter in the present docket with new proposed tariff language that it indicated was more narrowly focused on transformer upgrades as was originally discussed in the scope of the rate case. The Company stated that it "desires to resolve this issue and therefore provides proposed tariff modifications for a more targeted CIAC waiver for costs related to transformer upgrades needed to provide service to customers participating in our residential EV programs." The Company explained that it had notified the OAG of the filing ahead of time, and it was their "understanding that they do not have a procedural objection" but "did not express a final position on this proposal."[173]

i. Staff Analysis

Staff has not had time to review the tariff modifications in detail and there has not been time to solicit written feedback from participants in the docket. However, Staff notes that the Commission did approve the policy change for Xcel in its prior rate case and believes the scope of review for the letter should not be on whether stakeholders agree with the policy in the tariff, but rather whether the tariff changes conform with the rate case order. Therefore, Staff offers three procedural paths for the Commission's consideration:

1. Inquire with participants at the agenda meeting on whether they agree that the tariff changes comply with Order Point 65 of the June 17, 2023 Order in Docket E002/GR-21-630. If participants have no objections, approve Xcel's proposed tariff changes (**Decision Option 42**)
2. If participants would like additional time to review the tariff changes to see if they comply with the rate case order, institute a negative check off process whereby if no objections are received within 30 days, the Commission can delegate authority to the Executive Secretary to approve the tariff changes via notice. (**Decision Option 43**)
3. The Commission may deny the tariff changes, as recommended by the OAG (**Decision Option 44**)

Regardless of which path the Commission takes; Staff believes it would be beneficial to indicate that the CIAC waiver is still open for modification and discussion as part of the proactive upgrades and cost allocation workgroup discussed above. Staff reiterates it point from the TEP briefing papers that if Xcel is still making a transformer upgrade regardless of whether the customer is on a manage charging rate there is no avoided distribution system cost from off-peak energy use, simply a cost shift from the cost-causer to all customers.[174]

Staff also supports adopting the OAG's recommendation to require Xcel to track and report on the CIAC waivers granted to residential customers along with the revenues foregone as a result of the waiver. Staff believes the OAG's recommendation also encompasses the CEG recommendation to track and report on CAIC waivers. Staff recommends the Company submit

[172] CEG, Reply Comments, April 12, 2024, p. 1-3
[173] Xcel Energy, Letter, June 12, 2024, p. 1-2
[174] Staff Briefing Papers, Docket 23-452, March 20, 2024, p. 38

detailed information as part of its EV Annual Report and an aggregate amount in the IDP. Staff offers **Decision Option 45** as a combination of the OAG and CEG's recommendation.

8. Grid Modernization Initiatives

Xcel highlighted four major grid modernization projects that are approved and underway, outlined in Table 10.

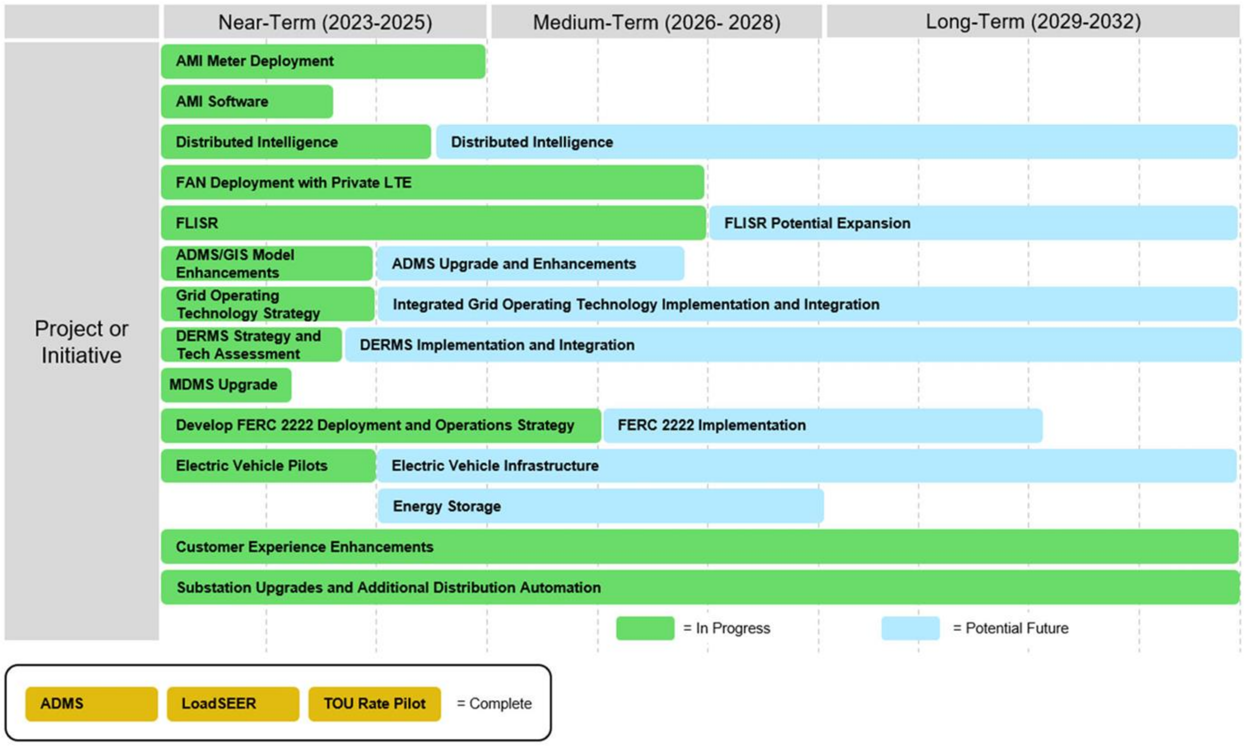
Table 10: Existing Grid Modernization Initiatives Underway[175]

Program	Implementation Timeline	Cost Recovery
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.	2019 TCR Rider (Docket 19-721) 2021 TCR Rider (Docket 21-814) 2023 TCR Rider (Docket 23-467)
AMI	Meter deployment began in 2022, with anticipated completion in 2025.	2021 TCR Rider (Docket 21-814) 2023 TCR Rider (Docket 23-467)
FAN	Initial network and security design was completed in 2020. First FAN device was installed and programmed in May 2021 and installation will continue through 2025.	2021 TCR Rider (Docket 21-814) 2023 TCR Rider (Docket 23-467)
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality will be available to the Minnesota control centers use starting in 2023 on select feeders and will be continued to be expanded to other feeders through 2027.	2022-2024 costs in base rates (Docket 21-630)

Xcel provided Figure 15 to illustrate its 10-year grid modernization plan, which includes additional potential investments such as a Distributed Energy Resource Management System (DERMS), Distributed Intelligence (DI), FERC 2222 Implementation, an expansion of FLISR, energy storage, and additional EV infrastructure.

[175] Xcel Energy, 2023 IDP Part 2 of 3, Appendix C, November 1, 2023, p. 4-5 (PDF p. 80-81), Table C-1

Figure 15: Illustrative Long-Term Grid Modernization Plan[176]



i. Department – Initial Comments

The Department determined that Xcel did not provide sufficient information on its near-term grid modernization investments to satisfy the Commission's filing requirements. It found that Xcel's response to Filing Requirement 3.D.2, the 5-year action plan for its distribution system and grid modernization investments did not fully meet compliance with the Commission's directives. Specifically, the Department pointed out that the Company has not provided cost-benefit analysis for DI, DERMS, and a potential successor to ADMS. Therefore, the Department recommended that the Company be required to refile Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects.[177] (**Decision Option 2a**)

The Department did not offer comments on individual gird modernization initiatives identified in Xcel's IDP and the Commission's notice but instead reiterated that the Company had not met its obligation to provide detailed information about near-term grid modernization efforts. The Department explained that without detailed cost benefit analysis in the IDP "there is a risk that the Company will move ahead with these investments and cost recovery requests without subjecting these investments to comprehensive review in the integrated context that is the IDP proceeding."[178]

---

[176] Xcel Energy, 2023 IDP Part 2 of 3, Appendix C, November 1, 2023, p. 12 (PDF p. 88). Figure C-3
[177] Department, Initial Comments, March 1, 2024, p. 4-5
[178] Department, Initial Comments, March 1, 2024, p. 35

Lastly, the Department sought clarification from the Commission on the filing requirement established by the Commission in Xcel's last rate case requiring a roadmap of planned and contemplated future grid modernization investments and a complete accounting of all historical and grid modernization costs and all anticipated future grid modernization costs with its IDP. The Department found that Xcel did not satisfy the "road map" requirement as the Company did not file the required level of detail on historical grid modernization expenditures. Therefore, the Department sought clarity on this IDP requirement.[179] (**Decision Option 46**) The Department also recommended delegating authority to the Executive Secretary to (1) expand the scope of the Distributed Generated Working Group (DGWG) or (2) create a new working group to address grid modernization issues. (**Decision Option 47**)

ii. Xcel Energy – Reply Comments

In reply comments the Company stated that it is unreasonable to require a cost-benefit analysis for all near-term grid modernization projects included in its plan. Xcel explained that many of its near-term grid modernization investments depicted in Figure 15 above are related to existing projects, such as AMI, FAN, FLISR, and ADMS, which have already been approved. Other grid modernization initiatives do not necessarily involve capital spending, such as "Grid Operating Technology Strategy," "DERMS Strategy and Tech Assessment," and "Develop FERC 222 Deployment and Operations Strategy," instead these are strategic planning initiatives to better prepare for the changing energy landscape. Other types of projects like "Customer Experience Enhancements" and "Substation Upgrades and Additional Distribution Automation" are in extremely early stages of development and are more of placeholders than concrete projects.[180]

Xcel reiterated that it has not made any proposals for grid modernization projects in its 2023 IDP, and that the appropriate place for the higher level of detail requested by the Department is in a cost recovery proposal. Xcel recommended the Commission decline the Department's recommendation to have it refile Appendix C: Action Plans with a cost benefit analysis for each near-term grid modernization project.

iii. Department – Reply Comments

In initial comments, the Department noted the lack of information on the costs and benefits of the grid modernization initiatives and determined the Company had not met its IDP filing requirements obligations. In response, the Company provided that it can only provide a cost-benefit analysis when a grid modernization project has been fully developed and cost recovery has been requested. At this stage, the Department disagrees with the Company's interpretation of the IDP filing requirement because it directs Xcel to provide for "a cost-benefit analysis based on the best information that [Xcel] has at the time."[181] In the Department's view, a cost-benefit analysis provides a critical comprehensive accounting of the benefits and costs, compared against alternative investments, that are appropriate for any grid modernization investment.

---

[179] Department, Initial Comments, March 1, 2024, p. 36
[180] Xcel Energy, Reply Comments, March 22, 2024, p. 20-21
[181] Department, Reply Comments, April 12, 2024, p. 7

CEEM also supports the Department's recommendation to require Xcel to refile Appendix C (**Decision Option 2a**).[182]

iv. Staff Analysis

Staff discussed its overall philosophy on the provision of cost benefit analysis in IDPs as part of the Joint Briefing Papers. In summary, Staff does not believe utilities should create formal, in-depth cost benefit analyses specifically for the IDP filing and instead they should be filed as part of an approval or cost recovery proceeding.

Staff reviewed the decision from the Commission's July 17, 2023 Order in Xcel's rate case to provide a road map of grid mod investments and accounting of historical grid mod investments with future proposals. Staff's interpretation of the order point is for Xcel to provide the requested information when it is submitting a proposal for Commission approval and cost recovery, not as part of the IDP. The rate case order does not discuss a modification of the IDP filing requirements, which already require a long-term distribution system modernization and infrastructure investment plan (Filing Requirement 3.D). If the Commission agrees with Staff's interpretation it could adopt the following decision option:

> Clarify that Order Point 128 from the July 17, 2023 Findings of Fact, Conclusions, and Order in Docket E002/GR-21-630 applies only to proposals where Xcel is requesting approval for grid modernization investments and is not an amendment to IDP filing requirements.

Staff notes that stakeholders provided specific recommendations about upcoming grid modernization investments outlined by Xcel in its IDP based on the information provided. As the Commission will read in subsequent sections, both Fresh Energy and GEC have precise recommendations relating to the Company's upcoming grid modernization investments and what information should be provided in a cost recovery proceeding, which they were able to provide based on the information in the instant proceeding.

A. Planned Net Load (PNL)

Xcel was tasked in the 2021 IDP to develop an initial methodology for considering the impacts of DER on peak loads for feeders and substations. Xcel introduced the concept of Planned Net Loading (PNL) in response to this requirement. PNL utilizes the concept that recognizes a portion of DER output can be depended upon to lower or shave peak demand which means that, in planning, equipment does not need to be built as large to be able to handle the full native load on the system. By recognizing dependable DER peak shaving ability, theoretically the distribution system can be smaller in size without losing reliability which is an overall savings to ratepayers.[183]

Xcel brought up the concepts of native loading, net loading, and a dependability factor in determining planned net loading. Xcel stated that native load is the actual demand on the distribution system without accounting for DER generation impacts. Net loading uses SCADA and is the "actual demand when all DER impacts are included."[184] For this first iteration of PNL,

---

[182] CEEM, Reply Comments, April 12, 2024, p. 3
[183] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 74 (PDF p. 129)
[184] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 74 (PDF p. 129)

Xcel decided to only include DER generation from CSGs and rooftop PV. However, Xcel noted that while net loading can cover a significant portion of demand on average, much of the generation is not reliable and should only have a portion of the DER generation assumed to be reliable in their future load analyses and planning. That portion is what Xcel calls the Dependability Factor of PV (DF_{PV}).

Regarding the dependability factor, Xcel stated that most PV DER cannot be relied upon fully as they are not dispatchable resources, often are not fully aligned with peak load, can be intermittent, and are dependent on weather patterns and seasonal changes among other factors.

Put together, Xcel offered the following formula to define PNL:[185]

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

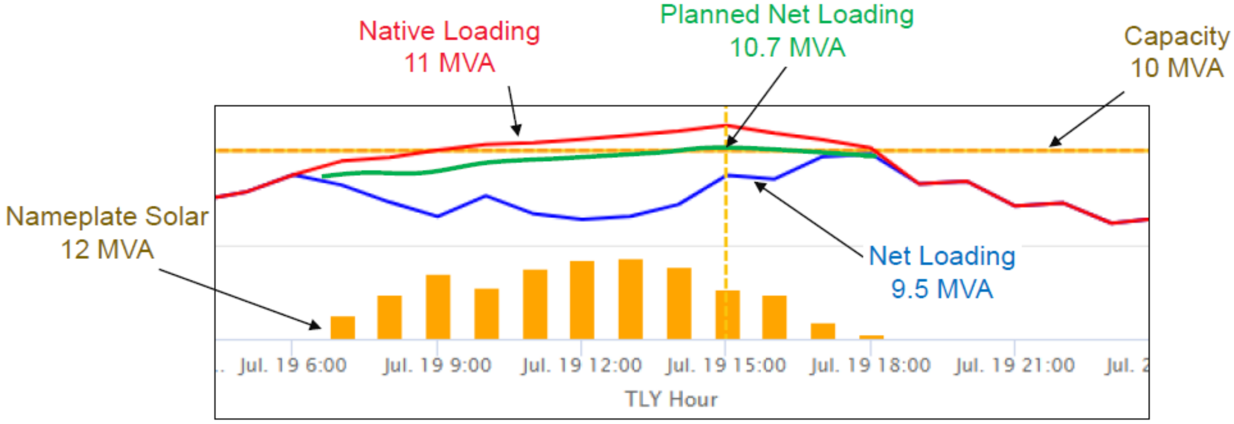
Where: DF_{PV} = Dependability Factor of PV solar generation

Net = The impact of the DER on Load

Native = The full native load on the system

Xcel provided a figure to demonstrate what these values mean on a peak load curve.[186]

Figure 16: Planned Net Loading Formula Applied to a Feeder N-0 Analysis



Xcel used a value of 15% for DF_{PV} for this example and thus the Planned Net Loading formula is as such:

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

Where the native load is 11 MVA, and net load (total DER generation) is 9.5 MVA. In this case the PNL is 0.3 MVA fewer than what would otherwise be used by Xcel's risk analysis process.

In this iteration of the NPL Xcel emphasized the need for reliability and risk assessment and chose a DF_{PV} of 15 percent. Xcel believed this to be prudent as it was based on an assessment based on the 2016-2021 timeframe of the recorded PV generation as a percentage of nameplate capacity rating from its Minnesota CSG program. The assessment found that the

[185] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 76 (PDF p. 131)
[186] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 76 (PDF p. 131)

November-January months had an average of 15% regarding generation as a percent of nameplate capacity. The assessment covered the following values listed in Table 11.[187]

Table 11: Average Monthly Solar Generation Output as a Percent of Nameplate Capacity

Time Range	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
00:00-23:59 All Day	7.1%	11.3%	14.3%	15.2%	18.0%	20.2%	20.2%	17.9%	15.4%	11.5%	8.2%	5.4%
08:00-18:00 Tracking	15.4%	24.5%	30.2%	31.1%	36.1%	40.4%	40.9%	36.8%	32.1%	24.4%	17.9%	11.8%
10:00-16:00 Fixed	21.7%	33.1%	38.4%	37.7%	43.1%	47.9%	49.2%	44.9%	39.9%	30.7%	23.3%	16.3%

Xcel noted that while the DF_{PV} was derived by a percentage of nameplate capacity, it is being multiplied against the DER generation "impact", the difference between native and net load, and not against the nameplate DER generation in the NPL formula. That means in the above example the 15% dependability factor is not multiplied against the 12 MVA of solar nameplate capacity but against the native load minus the net load, 1.5 MVA in this case.

Applying PNL

Xcel described the outlook of applying the PNL under three different scenarios. N-0, normal conditions, Failed Feeder N-1 and a substation transformer N-1.

Xcel stated that an overload on a feeder or substation transformer in a N-0 case solar remains online and is addressed by their Operations Team. In day-to-day operation the Distribution Control Center uses net loading to identify overloads. Xcel relayed that PNL could be utilized in planning for an N-0 in the future.

In a "feeder N-1" where there is an outage on a feeder, solar is tripped offline to protect the grid as well as the line crew. Xcel stated the feeder is then studied under native loading "due to considerations in safety, delay in restoration of the solar, and abnormal configurations having not been studied during interconnection studies."[188] However, if the out feeder has a feeder tie to another feeder with solar, the solar would remain online and PNL can be utilized.

In a "transformer N-1" where there is an outage on a feeder, solar can remain online if there is a bus tie that is closed in the substation, keeping the feeder in its original configuration. The transformer can be studied under PNL conditions in this case.

In essence, Xcel asserted that assessing the N-1 risk on the system using their version of the PNL would be similar to their current N-1 mythology. For example, in the case of downed feeder or substation Xcel studies whether the native load can be safely transferred to neighboring sources. They do not apply PNL to the downed feeders and substations as the DER would be disconnected for safety reasons. However, when transferring the load from those the

---

[187] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 78 (PDF p. 133)

[188] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 75 (PDF p. 130)

downed equipment to other feeders and transformers, Xcel would apply PNL to those sources taking in the new load as the DER would be supplying generation.[189]

PNL Risk Analysis

Xcel conducted a risk analysis that applied the PNL formula onto its system assuming a DF_{PV} of both 15% and 25% for its risk analysis assessment that runs against N-0 and N-1 (feeders and substation banks) scenarios. Tables 12 to 15 relay their findings: [190]

Table 12: Feeder Risks and Loading with 15% DFPV

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	8,599,767	8,564,857	34,910
Count of N-0 Risks	67	66	1
Count of N-1 Risks	540	536	4

Table 13: Feeder Risks and Loading with 25% DFPV

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	8,599,767	8,541,584	58,183
Count of N-0 Risks	67	63	4
Count of N-1 Risks	540	535	5

Table 14: Bank Risks and Loading with 15% DFPV

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	7,788,144	7,748,657	39,487
Count of N-0 Risks	13	13	0
Count of N-1 Risks	177	177	0

Table 15: Bank Risks and Loading with 25% DFPV

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	7,788,144	7,722,333	65,811
Count of N-0 Risks	13	10	3
Count of N-1 Risks	177	177	0

Xcel explained through their table results that PNL when applied to N-0 scenarios at a 15% DF_{PV} only reduces identified risks on feeders by 1 and does not reduce risks for capacitor banks on substations. The numbers increase slightly when a DF_{PV} of 25% is used as identified risks are reduced by 4 on feeders and by 3 on capacitor banks. When applied to N-1 scenarios, identified risks on feeders are reduced by 4 and 5 for DF_{PV} values of 15% and 25% respectively. PNL did not reduce risks for capacitor banks at either DF_{PV} value for N-1 scenarios. Xcel emphasized that while 25% may reduce the identified risks in planning it assumes that that the DER will be there

[189] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 77 (PDF p. 132)
[190] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 79 (PDF p. 134)

when the outages occur and that there is some increased system risk if the DER is not available at sufficient levels when a failure occurs.

Xcel stated that is open to moving forward with using a DF_{PV} value of 15% for N-0 risk analysis but that the Commission should recognize carefully weigh the theoretical benefits against the possibility of increased system risk and potential impacts to hosting capacity.[191]

i. Department – Initial Comments

The Department focused on the results of Xcel's risk analysis of applying the PNL using a 15% and 25% dependability factor. The Department noted that the 15% dependability factor only avoided one risk under the N-0 risk analysis and 7 under the 25% dependability factor and concluded that the PNL had limited benefit.[192] While the Department concluded the methodology reasonable it did not recommend Xcel implement the 15% dependability factor in the next planning cycle for the N-0 risk analysis (**Decision Options 49 and 50**).

i. Fresh Energy – Initial Comments

Fresh Energy stated it is glad to have an initial methodology in place to recognize the load-reducing impact of distributed generation but believes that Xcel's PNL methodology is "overly conservative and does not fully reflect the load-reducing impact from PV at the time of a feeder's peak load."[193] Fresh Energy highlighted that the 15% dependability factor that Xcel is using is not 15% of the nameplate capacity, but of the PV generation impact, the difference between native and net load, which is a much smaller in value.

Fresh Energy requested and received an example from Xcel of how it calculates PNL. In the example, Fresh Energy stated that the provided feeder had approximately 10 MW of PV nameplate capacity and a native peak load of 4.1 MW occurring at 5pm on July 19. The PV's output at 5pm each day in July ranged from 454 kW to 3.7 MW with an average output of 1.9 MW. In this example, Fresh Energy stated that Xcel applied the 15% dependability factor to the difference of the native peak load (4,113 kW) and the net peak load (3,733 kW) which ultimately led to only 57 kW of dependable PV out of the 10 MW of nameplate capacity according to Xcel. Fresh Energy noted that this is only 0.6% and emphasizes how conservative this methodology is.

Fresh Energy then asked Xcel if it agreed with their conclusions regarding the analysis of their PNL example and the conservative bent to the methodology. Fresh Energy also questioned why the Company used the average winter PV output for the dependability factor rather than the average summer output when the majority of Xcel's feeders peak in the summer months.

ii. GEC – Initial Comments

GEC had similar sentiments to Fresh Energy. It appreciated that Xcel is making progress in this direction but agreed that the Company's PNL methodology is overly conservative.[194] GEC

---

[191] Xcel Energy, 2023 IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 80 (PDF p. 135)
[192] Department, Initial Comments, March 1, 2024, p. 55
[193] Fresh Energy, Initial Comments, March 1, 2024, p. 14
[194] GEC, Initial Comments, March 1, 2024, p. 38

focused on the Company's choice to use the average of the winter months, 15%, for its dependability factor, rather than lowest of its summer months which was 36.83% in Xcel data sample. GEC stated that Xcel is leaving "usable capacity on the table rather than maximizing the value of available DER capacity" which is inefficient and costly instead of relying on "free-to-the-Company DERs." GEC stated that Xcel will have to acquire extra capacity and pass those costs onto its customers.

GEC requested the Commission require Xcel to refine its PNL methodology where it should consider:[195] 1) increasing its dependability factor and 2) seasonal and/or otherwise differentiated dependability factors. GEC also requested the Commission require Xcel to explain in its next IDP any decisions to change or not to change its dependability factor. (**Decision Option 48**)

iii. Xcel Energy – Reply Comments

In initial comments Fresh Energy and GEC claimed the 15% dependability factor, which was derived from the average PV output from the three winter months, was too conservative. Xcel responded by stating that it is important to remember that this is the first step in the PNL methodology and to consider realistic worst-case scenarios.[196] The Company continued that while most feeders currently peak in the summer, electrification increases over the next 30 years will lead many feeders to have a likelihood of peaking in the winter at similar or greater rates than in the summer. The Company claimed that it is important to plan for peaks that can occur throughout all times of the year and that the PNL methodology is designed to be flexible enough to be applied in either case.

The Company stated that applying seasonally differentiated dependability factors would "require a large effort by the Company and a significant amount of resources" as Xcel states that feeders may change from summer to winter peaking throughout the course of the forecast.[197] Xcel wrote that there are approximately 1,500 feeders and banks on its Minnesota system and 30 years of forecasted peaks which would require 45,000 unique and individual dependability factors.

Xcel requested the Commission find it's PNL methodology reasonable (**Decision Option 48**) and supported the Department's request to not implement the 15 percent D_{PV} in the next planning cycle for N-0 risk analysis. (**Decision Option 50**) Xcel does not support GEC requests regarding increasing the dependability factor or using a seasonal/differentiated dependability factor.[198]

iv. Fresh Energy – Reply Comments

Fresh Energy reiterated its assertion that the proposed PNL methodology "is overly conservative, significantly underestimates PV's impact, and may be leading to unnecessary capital investments."[199] Xcel did not dispute Fresh Energy's finding that the PNL formula used

---

[195] GEC, Initial Comments, March 1, 2024, p. 39
[196] Xcel Energy, Reply Comments, March 22, 2024, p. 48
[197] Xcel Energy, Reply Comments, March 22, 2024, p. 48
[198] Xcel Energy, Reply Comments, March 22, 2024, p. 48
[199] Fresh Energy, Reply Comments, April 12, 2024, p. 5

would determine only 0.6% of 10 MW of PV nameplate capacity as dependable in the Company's provided example. Fresh Energy acknowledged that developing seasonal dependability factors would require additional work for Xcel but claimed that doing so would more accurately reflect the load-reducing impact of PV and that having a minimum of a summer and winter dependability factor would be a reasonable next step.

Fresh Energy believed that the Department's conclusion to not apply the current PNL methodology in planning is because of the impact on planned impacts and that it did not consider or explore whether the PNL methodology should be done differently or consider different factors. Fresh Energy believed "it is reasonable for the Company to take a second look at its PNL methodology and evaluate the impact of methodology refinements", including applying it to hourly PV generation and to PV nameplate capacity.[200] Fresh Energy also requested that the Commission require Xcel to engage parties that commented on PNL in this proceeding as it evaluates seasonal dependability factors and alternative PNL approaches. It requested that Xcel include a report describing the results of this evaluation and changes to its proposed PNL methodology in its next IDP.

Based on this analysis, Fresh Energy recommended **Decision Option 49**.

The City of Minneapolis supports Fresh Energy's recommendation to convene stakeholders to this end if the stakeholder process is led by a neutral third party.[201]

v. GEC – Reply Comments

GEC maintained its positions and claimed that Xcel did not address the substance of its concerns other than to say that the Company disagreed with GEC about how conservative their 15% dependability factor is.[202] In addition to its prior recommendations, GEC also supported requiring broader stakeholder engagement on this topic consistent with its effective stakeholder energumen section (**Decision Option 49**).

vi. CEEM – Reply Comments

CEEM requested that Xcel provide additional information for analysis, briefing, and address the following questions:[203] what industry practices provide the basis for the 15% Dependability Factor? What standards are used to provide the basis for the 15% Dependability Factor?

vii. Staff Analysis

Planned Net Loading is Xcel's response to the Commission requirement that the Company consider DER impacts to peak loads on feeders and substations and its impact on planning. Theoretically, DERs on the distribution system can be relied upon to a certain extent in planning which can lead to requiring fewer, smaller, or less costly capacity expansion investments. The following formula is Xcel initial methodology for calculating PNL:

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

---

[200] Fresh Energy, Reply Comments, April 12, 2024, p. 7
[201] City of Minneapolis, Reply Comments, April 12, 2024, p. 1
[202] GEC, Reply Comments, March 12, 2024, p. 22
[203] CEEM, Reply Comments, April, 12, 2024, p. 5-6

Where: DF_{PV} = Dependability Factor of PV solar generation

Net = The impact of the DER on Load

Native = The full native load on the system

Xcel chose 15% as its dependability factor after calculating the average percent of nameplate capacity of PV tracking from 08:00-18-00 (8am to 6pm) during the November, December, and January months. Xcel believed this to be prudent and low risk for its initial PNL iteration. Xcel provided an example feeder where the PNL values offered very modest gains compared to native load, even with 12 MW of nameplate PV on the system. Its benefits in risk analysis also proved to be minimal, only avoiding one feeder N-0 risks, four N-1 feeder risks, and zero capacitor bank risks. Due to these minimal risks the Department recommend Xcel not move forward with using PNL with its N-0 planning and Xcel agreed. Staff is unsure of Xcel's position in its reply comments whether the Company is willing to drop the PNL methodology altogether or at the very least agreeing to not adjusting its PNL methodology any further. It is unclear what Xcel's position is on the PNL going forward.

However, GEC and Fresh Energy believe Xcel's PNL methodology is overly conservative and does not adequately capture the benefits of DERs regarding their load-reducing impact. Staff tends to agree with this assessment. There are two areas of conservatism built into Xcel's PNL, using a percent of the *impact* of PV generation rather than a percent of the nameplate capacity, and using 15% as the dependability factor.

Staff understands Xcel wants to start small as this is the first iteration of PNL and there can be consequences if the mark is missed too drastically in planning and assessing risk. Despite this, Staff is still in agreement with GEC and Fresh Energy that this first iteration is too conservative. To emphasize how conservative this formula is, Staff provide the following comparison of the impact Xcel's example had in its IDP:

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

Where the PNL is 0.3 MW fewer than the 11 MW it normally would have planned for with native load. This is assuming a 15% dependability factor with a 12 MW PV nameplate capacity.

You can compare this PNL value with the same scenario but rather than multiplying the dependability factor by the impact of the PV, instead multiply the nameplate capacity by the lowest Average Monthly Solar Generation Output as a Percent of Nameplate Capacity from Table 11, which is 5.4% from December. This 5.4% value is also the average output as a percent of nameplate capacity over a complete 24-hour period as opposed to an 8am-6pm period which is where the 15% value was derived. This means the value is much more conservative of a value than would be expected to see during the day, be it in the winter or in the summer. Using those numbers, you get the following:

$$Planned\ Net\ Loading = 11 - 12 \times 5.4\% = 10.35\ MVA$$

This means that this version of PNL would save you 0.65 MVA in planning compared to the 0.3 MVA Xcel PNL used, more than double. This is despite using an average nameplate percentage output from the lowest output month, December, and using a 24-hour average when much of the day does not have sunlight.

Staff is not suggesting this is the correct PNL methodology to use but is using it as an example to emphasize that the PNL methodology does not appear to be useful in its current form due to how conservative it is. This is made more indicative with the results from Xcel's PNL risk analysis where only one N-0 risk was avoided with a 15% dependability factor and four with a 25% DF. However, Staff does not believe this minimal impact is due to the idea of PNL not being worthwhile, but instead that the implementation of PNL is flawed. Staff notes that the Department focused only on the absolute results of the PNL risk analysis and concluded that it was not useful, rather than questioning the methodology that Xcel was tasked with creating or considering alternative models.

When pressed on why Xcel uses winter months and not summer months for its dependability factor when Xcel's feeders experience peak loading days, Xcel stated that using the average PV output during winter months for its dependability factor is prudent because electrification over the next 30 years will have many feeders experience peak demands in the winter. Staff notes that Xcel is not clear when over the next 30 years Xcel believes this will happen. However, it seems reasonable to Staff to assume that this is unlikely to happen to a significant number of feeders over the next decade. Additionally, Staff notes that millions of dollars of the distribution system budget has been, and will continue to be, allocated to grid modification efforts which give greater insight into the grid to make it more predictable and easier to forecast. Staff believes that these investments and subsequent grid insights should give Xcel enough lead time to prudently adjust its dependability factor on given feeders as needed. Additionally, increasing load flexibility measures should give Xcel the ability to match load like EV charging to solar generation. Staff is not convinced by Xcel's reasoning to use the winter months in calculating the dependability factor in its PNL methodology.

Staff would like to emphasize that one of the key benefits of DER generation and why it is sometimes given priority over other sources of generation is its peak load shaving ability. It is also one of the listed values that contributes to the VOS, or the "Value of Solar" methodology. However, thus far, this ability has not been utilized and Xcel has built its distribution system assuming zero DER impact on this end, "leaving usable capacity on the table" as GEC described in their initial comments. The Commission requiring Xcel to create a methodology to consider DER impact on peak loads on feeders and substation transformers was the Commission's first step to start unlocking this beneficial aspect of generation DER, of which there are over 1,000 MW of solar PV on Xcel's distribution system alone. Getting to a useful PNL methodology is important, in the public interest and its refinement should be continued. This is especially true as Xcel's distribution system capacity expansion budget has ballooned to over $1 billion over the next three years. A proper PNL would actively put downward pressure on this budget and thus also provide some reprieve to ratepayers.

That said, Staff supports Fresh Energy and GEC's suggestions that Xcel refine the PNL methodology, consider applying a seasonal dependability factor, and evaluate applying it to hourly PV generation and to PV nameplate capacity. Staff also supports Fresh Energy's other recommendations regarding Xcel engaging parties on PNL proceedings and including a report in the next IDP. (**Decision Option 49**).

Staff also supports Xcel applying the current PNL using a 15% dependability factor for N-0 risk analysis in the next IDP (**Decision Option 51**). Xcel was originally supportive of this in their initial filing and only moved from this position when the Department suggested otherwise. As mentioned in this briefing paper thus far, this PNL offers very little risk due to is conservative nature, but also minimal benefit. However, Staff sees benefit in Xcel gaining experience in applying some version of the PNL even if the PNL may be modified in the future.

B. FI and DERMS

i. 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.[204]

In its IDP, Xcel stated that there are still several technological, economic, and policy questions to answer before FI can be deployed as a standard offering. The Company claimed it is currently and has planned to answer those questions. First, Xcel noted that the new advanced inverter settings were chosen in part to be compatible with FI. Second, they partnered with EPRI to work "on the techno-economic study of flexible interconnection with utility scale solar PV systems" to investigate the economic and technical feasibility of actively managing solar resources to enhance energy production and use of available feeder capacity, with the consideration of grid constraints."[205] Xcel added that they were awarded technical assistance from the Department of Energy on FI through Interconnection e-Xchange (i2X) Technical Assistance Opportunity. The Company is also working with Pacific Northwest National Lab and partnering with Commonwealth Edison to create a best practice guide for FI.

Xcel also noted that it will demonstrate its first use of FI capabilities in Colorado through two pilot projects that are to be implemented by the end of 2024. They plan on testing and demonstrating local and autonomous smart inverter settings combined with scheduled curtailments based on historic and forecasted power flow and then taking those findings to its operating group in Minnesota.[206]

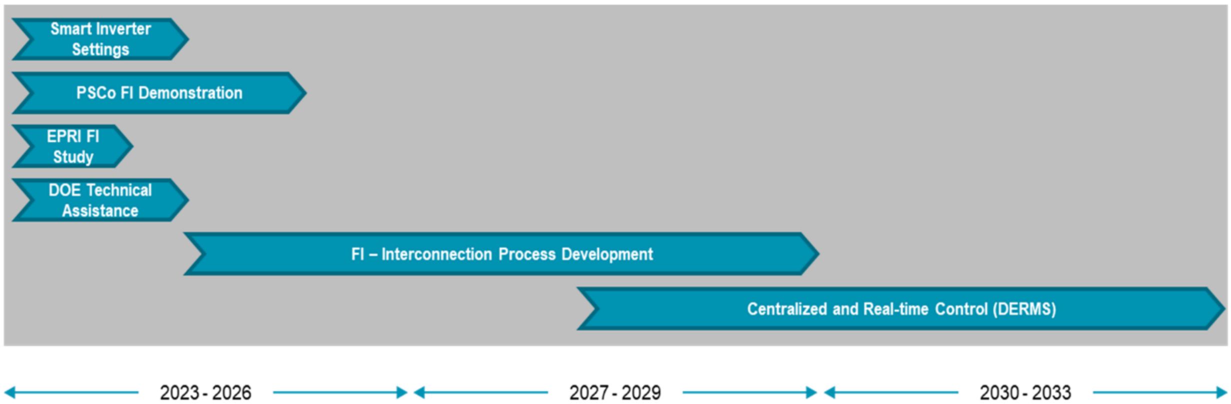
Xcel plans to have its first phase of FI implementation to be based on local and autonomous control which relies on advanced inverter technology and its existing infrastructure and software. Xcel expected that this offering will be available in the mid-term (2027-2029). The larger scale implementation of FI, where there are multiple flexible interconnections on a substation or feeder, requires more active grid management and a centralized control software to dynamically manage those DERs. Xcel stated that a Distributed Energy Resource Management System (DERMS) "is one type of control software capable of providing this

---

[204] Xcel Energy, IDP Part 2 of 3, Appendix E, November 1, 2023, p. 4 (PDF p. 120)
[205] Xcel Energy, IDP Part 2 of 3, Appendix E, November 1, 2023, p. 5 (PDF p. 121)
[206] Xcel Energy, IDP Part 2 of 3, Appendix E, November 1, 2023, p. 6 (PDF p. 122)

coordinated control" as it would be able to "calculate the optimal curtailment of multiple FI-participating DER on a feeder or substation based … and would automatically dispatch curtailment signals as appropriate."[207] However, Xcel emphasized that a DERMS would require many pilot projects, demonstrations, testing, analysis as well as new trainings and processes before it can be safely integrated with grid operations.

Figure 17: Flexible Interconnection Roadmap[208]



ii. DERMS

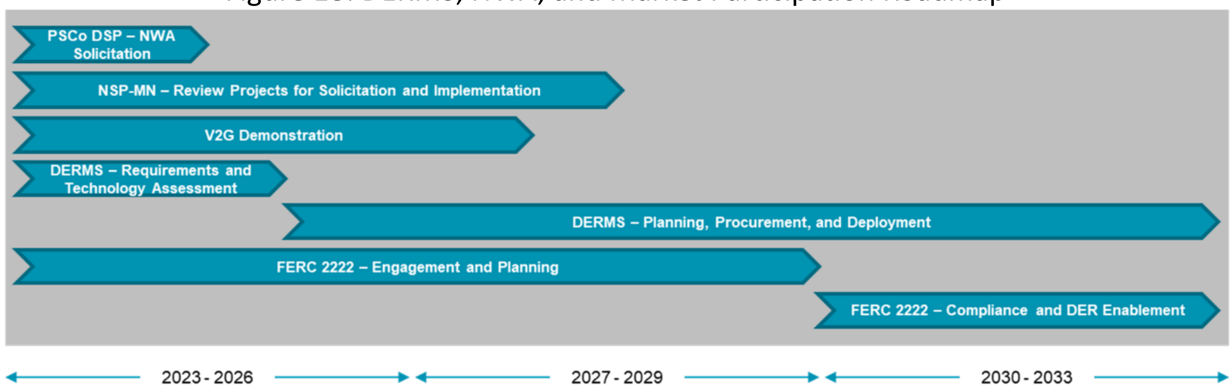
A Distributed Energy Resources Management System (DERMS) is a software platform that works toward aggregating and organizing the diverse and numerous DERs on the distribution system. These DERs include solar and wind system, energy storage, and demand response (DR) devices. The increase in monitoring and control from DERMS allows the utilities to actively manage voltage, optimize power flow, and generally improve reliability and resilience. Xcel stated that the purpose of a DERMS "is to enhance the integration and utilization of DER to meet the needs of the grid, customers, the market, and regulatory entities" and believes it to be a "necessary step to integrate higher levels of DER."[209] The Company stated that DERMS would interact with other systems such as ADMS, FAN, AMI, and the internet.

Xcel listed leveraging energy storage to reduce peak usage, integrating more renewables, managed charging scenarios for electric vehicles as potential use cases for DERMS. Xcel also believed that DERMS will be part of the solution to meeting FERC Order 2222 which Xcel expects to drive "new business requirements, new operational dynamics between distribution and transmission, and potential market implications between retail and wholesale markets."[210] Xcel stated that DERMS would also enable the "centralized control and optimal dispatch of flexible interconnections and would aid operations in the coordination and management of NWAs."[211]

[207] Xcel Energy, IDP Part 2 of 3, Appendix E, November 1, 2023, p. 4 (PDF p. 120)
[208] Xcel Energy, IDP Part 2 of 3, Appendix E, November 1, 2023, p. 5 (PDF p. 121)
[209] Xcel Energy, IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 24 (PDF p. 24)
[210] Xcel Energy, IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 24-25 (PDF p. 24-25)
[211] Xcel Energy, IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 25 (PDF p. 25)

Xcel stated that DERMS and its potential use cases are still being studied and that the Company has partnered with Electric Power Research Institute (EPRI) to research these potential use cases as well as to understand the necessary requirements, resources, and training needs to support DERMS.[212] Xcel emphasized that balancing DERMS deployment and infrastructure investment will be critical to support the goals for increasing DER and electrification. The Company recommended a phased implementation approach for DERMS to meet policy, regulatory, customer, and business needs.

Figure 18: DERMS, NWA, and Market Participation Roadmap[213]



iii. GEC – Initial Comments

Flexible Interconnection

GEC generally supported flexible interconnection but acknowledged its complexity and again emphasized the need for Commission oversight and for Xcel to be "transparent about the conditions under which the Company will use flexible interconnection, particularly with impacted DER owners/operators."[214] GEC stated that flexible interconnection would require many aspects of the current interconnection paradigm to be changed and cites cost allocation, risk, and curtailment prioritization as a few areas that require decisions to be made.

GEC believed the full implementation of FI may take time and offers that the Commission require Xcel to take a staged approach to FI, DERMS, and Dynamic Hosting Capacity (DHC), and that Xcel implement static FI, specifically, before any DERMS approval. [215] GEC stated that "Static FI" does not require advanced monitoring and control technology and can be done with local control systems by essentially setting a pre-set threshold that DERs cannot export beyond. GEC provided an example of a 2MW PV system and 2MW Battery Energy Storage System and how it would normally need to be studied with a theoretical maximum of 4MW exporting but by implementing static FI, the maximum export threshold can be set to 2MW. GEC suggested that if Xcel can demonstrate static FI, it can give the Commission confidence in supporting Xcel to implement full FI and help justify investment in DERMS.[216]

[212] Xcel Energy, IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 25 (PDF p. 25)
[213] Xcel Energy, 2023 IDP Part 2 of 3, Appendix E, November 1, 2023, p. 7 (PDF p. 127)
[214] GEC, Initial Comments, March 1, 2024, p. 24
[215] GEC, Initial Comments, March 1, 2024, p. 25
[216] GEC, Initial Comments, March 1, 2024, p. 26

GEC suggested that Xcel should take a "tiered" approach to implementing FI, DERMS, and DHC in order to maximize the potential of its current equipment since it believes that DERMS may not be necessary in all circumstances to integrate higher volumes of DERs. Additionally, a tiered approach allows for stakeholder engagement with each tier of implementation. GEC suggested the following tiers and timelines: [217]

Tier 1: Autonomous and Dynamic Functions – Immediate Near Term

Activation of tuned smart inverter functions such as volt-watt, and the utilization of hosting capacity analysis-informed and time-dependent export scheduling by the controls internal to the DER systems.

Tier 2: Local Edge-Device Controlled – Immediate Near Term

The utilization of grid edge devices placed near constrained grid equipment that monitor voltage and/or current for moments nearing a violation until a point in which curtailment controls for local DERs are triggered to avoid exceeding system thresholds.

Tier 3: EDC-Informed, Third-Party Aggregator DER Control – Mid-Term, 2-3 Year Timeframe

Pair circuit health information, which is obtained from local grid edge devices, with the control capabilities of third-party aggregators, which have monitoring and control capabilities over multiple DERs, to alleviate system congestion whenever it occurs.

Tier 4: System-Wide Centralized Control (DERMS) – 2028 Implementation

Deployment of system-wide, coordinated, and centralized DERMS.

DERMS Justification

GEC agreed with Xcel that DERMS has the potential to integrate more DERs, which GEC supports, and sees several other benefits to be had from the management of DERs with DERMS. However, GEC emphasized that it is critical for the Commission to provide Xcel with guidance regarding its evaluation of DERMS deployment now before significant decisions are made.[218] GEC urged the Commission to proceed with caution to ensure the potential high costs of DERMS is thoroughly scrutinized and that Xcel demonstrates the capabilities of its current DER tools, including through static Flexible Interconnection as well as provide more robust justification for any DERMS investment prior to receiving Commission approval.[219]

Roadmap

Pursuant to their request for more transparency and stakeholder input, GEC requested the Commission require Xcel to provide "a clear vision for DERMS along with a detailed roadmap showing the expected path to full implementation" (**Decision Option 56**).[220] GEC requested the

[217] GEC, Initial Comments, March 1, 2024, p. 27-28
[218] GEC, Initial Comments, March 1, 2024, p. 23
[219] GEC, Initial Comments, March 1, 2024, p. 23
[220] GEC, Initial Comments, March 1, 2024, p. 28

Commission ensure Xcel has adequately answered the following before any DERMS investments are approved:

1) What are the alternatives to DERMS?
2) What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries?
3) Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems?
4) How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure?
5) How will capacity be allocated across new and existing managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered?
6) How will prospective applicants understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?
7) What are the expected deployment and integrations costs for DERMS? What is the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered?
8) How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?

GEC also requested the Commission "require Xcel to solicit and prove it has achieved a critical threshold of stakeholder input, particularly from DER owners/operators, in advance of submitting any DERMS roadmap or proposal" and have Xcel describe its stakeholder engagement process, the feedback it received and how it was addressed (**Decision Option 55**).[221]

iv. Xcel Energy – Reply Comments

Regarding the parties' requests that the Company provide "certain information" in the IDP before Commission approval of DERMS investments, the Company indicated it will have to submit detailed information on project objectives, costs, benefits, cost-effectiveness, and timing when they seek approval and cost-recovery and that the IDP does not involve prudency determinations.[222]

Regarding the tiered implementation of FI and DERMS, Xcel stated this approach "demonstrated a fundamental mischaracterization of Flexible Interconnection and DERMS capabilities." Xcel continued by stating that while it may be able to facilitate rudimentary

[221] GEC, Initial Comments, March 1, 2024, p. 30
[222] Xcel Energy, Reply Comments, March 22, 2024, p. 23

localized FI agreements with smart inverters settings, coordinating multiple DER sites will require advanced control logic and coordination which is typically enabled by Grid DERMS.

Xcel described DERMS as being an "ecosystem of related and integrated software tools, business, planning, and operational processes that enable functional outcomes for specific use cases." [223] That ecosystem includes two software systems, Aggregator DERMS which Xcel plans to implement first in its roadmap, and Grid DERMS, which Xcel plan to implement to focus on priority use cases.

Aggregator DERMS utilizes a cloud-based "software as a service" model to quickly deploy customer-facing programs and should work with legacy demand response management systems (DRMS) which includes demand response, smart thermostats, batteries, and EV chargers. Aggregator DERMS deployments typically "focus on small-scale customer-sited resources that will allow the Company to communicate with existing equipment via the open standards (e.g., 2030.5, APIs) to dispatch signals to manage these resources upon customer sign-up and interest" and Xcel stated it is part of its "no regrets" strategy for modernizing new and existing load flexibility products but typically lacks real-time visibility and control, a function of Grid DERMS.[224]

Grid DERMS is typically integrated with SCADA and ADMS and can provide real-time and near-real-time visibility and control capabilities and functions but may require additional hardware for large-scale DER control. Xcel stated that Grid DERMS is more technically challenging and costly relative to Aggregator DERMS but offers "significant benefits of enhanced integration and connectivity, which will be necessary as DER penetration increases over time."[225]

Xcel stated that it is in the early stages of exploring initial, priority use cases for Grid DERMS which they believe is a crucial step to ensure prudency and that it will provide the expected benefits to customers, the system, and the Company. Xcel maintained that its incremental approach provided in their DERMS roadmap is the correct approach and is transparent. Xcel requested the Commission "decline the GECs' recommendations regarding our implementation of and roadmap for DERMS and for the Company to demonstrate prudency for any DERMS investments in the IDP".[226]

v. GEC – Reply Comments

GEC denied that it requested a prudency review from Xcel regarding any DERMS investment but rather seeks more transparency regarding DERMS "use cases, planning, and opportunities for stakeholders to provide input and the Commission to provide guidance before Xcel files certification for cost recovery when decisions are likely already made."[227] GEC believed Xcel has not provided sufficient information to understand its short and long term goals or the benefits and costs to ratepayer and reiterates that requiring Xcel to follow GEC's suggested road map

[223] Xcel Energy, Reply Comments, March 22, 2024, p. 24
[224] Xcel Energy, Reply Comments, March 22, 2024, p. 24-25
[225] Xcel Energy, Reply Comments, March 22, 2024, p. 25
[226] Xcel Energy, Reply Comments, March 22, 2024, p. 25
[227] GEC, Reply Comments, April 12, 2024, p.15

would give the Commission enough information to assess and guide the development of Xcel's DERMS investments now rather than after Xcel applies for cost recovery.

Regarding stakeholder engagement, GEC reiterated its request made in its initial comments. In addition to those comments, GEC believed the topic of FI could be taken up by the Distributed Generation Working Group (DGWG). Regarding DERMS, GEC recommends either the Commission expand the scope of the DGWG or create a new working group (**Decision Option 57**). The City of Minneapolis and CEEM supported these working group recommendations as well and the general push for more stakeholder engagement.[228] GEC also emphasized that any DERMS or FI working group should be led by a neutral third party.[229] (**Decision Option 58**)

GEC believed that there may be a misunderstanding regarding Xcel's response to its tiered approach to FI and DERMS as GEC sees Xcel implementing the Aggregator DERMS before Grid DERMS as in line with their recommendations. GEC reiterated its recommendations made in its initial comments that Xcel "maximizes and optimizes its use of existing and near-term technologies; Xcel clearly articulates the use cases and programs that the DERMS will enable or support."[230] GEC again emphasized that DERMS should have proper Commission oversight and stakeholder engagement now, before Xcel approaches the Commission with a "fully baked" proposal that may elicit significant concern and opposition and that requiring a detailed roadmap, stakeholder engagement, and a staged approached will help ensure a successful DERMS proposal.

vi. Fresh Energy – Reply Comments

Fresh Energy and the Department supported GEC's recommendations to engage experts as well as DER owners and developers during creation of the roadmap.[231] Specifically, Fresh Energy supported the Commission requiring Xcel to "(1) provide a detailed roadmap for DERMS deployment that addresses at least the questions in GEC initial comments and (2) conduct robust stakeholder outreach, including with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving, etc.), the feedback it received, and how it has addressed it." Fresh Energy suggested that the roadmap could be filed as part of the 2025 IDP or alongside any cost recovery for any DERMS technology.

Fresh Energy and CEEM also supported GEC's FI requests to have Xcel "demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: (1) implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and (2) pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation."[232]

[228] Minneapolis, Reply Comments, April 12, 2024, p. 1; CEEM, Reply Comments, April 12, 2024, p. 3
[229] GEC, Reply Comments, April 12, 2024, p. 16-17
[230] GEC, Reply Comments, April 12, 2024, p. 17
[231] Fresh Energy, Reply Comments, April 12, 2024, p. 12; Department, Reply Comments, April 12, 2024, p. 25
[232] Fresh Energy, Reply Comments, April 12, 2024, p. 12; CEEM, Reply Comments, April 12, 2024, p. 4

vii. Department – Reply Comments

The Department did not make comments regarding the merits of DERMS, instead it focused on whether Xcel had met filing requirements to provide cost benefit analysis for grid modernization investments under filing requirement 3.D.2, as explained in Section 8: Grid Modernization Initiatives.

Regarding the Department's comments, Xcel specifically responded to its claims on DERMS, stating that it is taking a "measured and use case-based approach to implementing DERMS" and that it is therefore "premature to provide a detailed evaluation of investments for DERMS." Xcel adds that they have concerns providing detailed cost information as vendors would have access to this information and could impact the Company's ability to secure favorable pricing. Xcel finishes stating that it will include all required information for DERMS when the Company is ready to seek cost recovery. [233]

viii. Staff Analysis

Flexible Interconnection Phase One

The concept of flexible interconnection and the move toward dynamic flexible interconnection garners general support from all parties and Xcel has been taking steps towards preparing for its potential implementation with a Flexible Interconnection Capacity Solution case study with EPRI and its implementation in its pilot projects in its Colorado jurisdiction.

Staff's understanding of FI is that there are likely to be two phases for its implementation. The first will be smaller scale utilizing local and autonomous control systems via smart inverters, what GEC calls "static flexible interconnection." The second phase requires a platform like DERMS and can control several flexible interconnections on the same feeder or substation and is far more dynamic.

Despite some apparent misunderstandings, Staff believes that GEC, Fresh Energy, and Xcel are in relative alignment on implementing FI in this first phase before moving toward the second phase as GEC's first two "tiers" seem very similar to Xcel's first phase for FI implementation where they estimate full implementation for in the 2027-2029 range. Staff supports this approach and believes it will give Xcel and the relevant parties experience in flexible interconnection before scaling up to coordinate multiple DER sites which would require a platform like Grid DERMS (**Decision Options 52**).

However, even implementation in the mid-term and at a localized scale, there are still several remaining questions to be answered regarding how exactly FI will work and under what conditions they will be applied. Staff agrees with GEC that the DGWG is equipped to handle this first stage of interconnection (**Decision Option 54**).

DERMS and Flexible Interconnection Phase Two

DERMS is a software platform that would be able to utilize ADMS, FAN, and AMI investments in order to aggregate, organize, and utilize large suites of DERs on the distribution grid. DERMS

---

[233] Xcel Energy, Reply Comments, March 22, 2024, p. 12

would enable voltage management, optimize power flow, improve reliability, and resilience, and allow for dynamic flexible interconnection. Parties agree that there are many benefits to DERMS and its operation.

Xcel specified the difference between Aggregator DERMS and Grid DERMS. Aggregator DERMS uses legacy demand response management system (DRMS) and is typically deployed to small-scale customer-sited resources and is a part of Xcel's "no regrets" strategy for modernizing new and existing load flexibility products, but ultimately lacks real-time visibility and control applications. Grid DERMS on the other hand, is typically integrated with SCADA and ADMS and is able to provide real-time visibility and control capabilities, can control large swaths of DERs, and is typically what enables the more dynamic aspects of control and operation that is described in the record.

GEC, Fresh Energy, CEEM, and the City of Minneapolis supported DERMS generally but believe that Xcel has been opaque in their roadmap, planning, and potential use cases, and requested Xcel be more transparent and offer more direct stakeholder engagement and outreach opportunities with relevant parties. Xcel has interpreted this as a request for prudency review for a technology/system that is still being developed and believe it to be not in the public interest to do so at this time.

While Staff understands the Company's point that DERMS and its use cases are still being studied, Staff believes there is room between a full prudency review and being transparent with the information the Company is working with and offering opportunities for stakeholder engagement. The IDP is meant to be informative, and decisions are not yet being made. Staff tends to agree with GEC that early involvement with stakeholders as well as Commission guidance for a project as large as DERMS, and a project with a runway as long as DERMS, is in the public interest. Early stakeholder involvement can be beneficial to the Company as well through removing future friction by resolving issues before they become more solidified in the overall DERMS plan. Staff does not see any harm in requiring Xcel to provide a more detailed roadmap for their DERMS implementation and requiring Xcel to be transparent with its stakeholder engagement process (**Decision Option 56 and 53**).

Staff notes that the Company does not need to have the answers to every question immediately as it works through its DERMS roadmap, just that they be willing to engage with stakeholders and be transparent about the information and assumptions they are currently operating under.

Staff does not support expanding the scope of DGWG to include DERMS, as GEC suggests, as the DGWG already has a long priority list and is more directly related to interconnection and its technical components.

C. Distributed Intelligence (DI)

Distributed Intelligence (DI) "refers to the distribution of computing power, analytics, decisions, and action away from a central point to the "edge" of the distribution grid. DI distributes these utility functions closer to localized devices or platforms, such as AMI meters or other "smart" devices on the distribution grid." Xcel's AMI meters are DI capable meters.[234]

Xcel Energy first submitted Distributed Intelligence (DI) as a certification request with its 2021 IDP in Docket 21-694. The Company later withdrew its request for DI and resubmitted it through supplemental testimony its 2021 Rate Case in Docket 21-630. The Commission rejected Xcel's DI proposal without prejudice, stating:

> Xcel has not met its burden to show that its proposed DI costs are just and reasonable. The Department raised important concerns about the assumptions and methodology underlying Xcel's cost-benefit analysis, and Xcel has not satisfactorily resolved those concerns. Although Xcel has identified potential uses of DI to help customers understand and control their energy usage and help the Company manage its distribution system more efficiently, the Commission is not persuaded that approval of Xcel's proposed DI program is justified based on the current record.
>
> However, in recognition of the potential benefits suggested in the record, the Commission will direct Xcel to re-file its DI proposal in its next IDP. The Commission agrees with the OAG and the ALJ that there may be merit in allowing Xcel another opportunity to support its proposal with a more fully developed record that addresses the concerns discussed herein. Additionally, as Xcel agreed, the proposal to be filed in the next IDP shall be consistent with the settlement entered into by the Company's Colorado affiliate relating to a similar program.[235]

In its 2023 IDP Xcel filed Appendix J which summarizes the Company's updated plans for DI. The Company indicated it plans to roll out several programs, My Energy Connection releases, Software Development Kits, and Xcel Energy Launchpad, before it seeks cost recovery in a future proceeding.[236]

On April 12, 2024, Xcel filed a modification to its 2024-2026 Energy Conservation and Optimization (ECO) Plan which included Home Energy Insights which "informs customers of how and when they use energy via Home Energy Reports, My Energy Portal, and High Bill Alerts" using the Home Area Network (HAN) and Distributed Intelligence (DI) capabilities embedded in its AMI meters. On June 11, 2024 the Deputy Commissioner of Commerce denied the modification, stating:

> The Deputy Commissioner understands that this project is also included in Docket 21-630 (Xcel's 2022 electric rate case) before the Minnesota Public Utilities Commission (MN PUC) and that the MN PUC rejected the Company's proposal for the program and directed the Company to refile a proposal in its next Integrated Distribution Plan consistent with the settlement for a similar program in the Company's Colorado service territory. For this modification, Xcel should settle this matter with the MN PUC prior to proposing a program in its ECO Plan.

---

[234] Xcel Energy, 2023 IDP Part 3 of 3, Appendix J, November 1, 2023, p. 2 (PDF p. 206)
[235] July 17, 2023 Order in Docket 21-630, p. 59
[236] Xcel Energy, 2023 IDP Part 3 of 3, Appendix J, November 1, 2023, p. 33 (PDF p. 237)

> In reviewing the Petition submitted, the Deputy Commissioner also has concerns about the technical assumptions Xcel has proposed for validating customer energy and demand savings. Once matters have been resolved at the MN PUC, the Deputy Commissioner encourages the Company to work with Department Staff to develop a thorough description of the program, explanation of procedures for documenting savings, and reporting expectations.[237]

Xcel Energy, 2023 IDP Part 3 of 3, Appendix J, November 1, 2023, p. 2 (PDF p. 206)

i. Department – Initial Comments

The Department concluded that Xcel had not provided the necessary information on DI, specifically the Company did not provide an updated cost benefit analysis. In the Department's view, without a CBA the Company's filing does not qualify as a "proposal" under the Commission's July 17, 2023 Order. The Department pointed out that Xcel planned to file part of DI as a modification to its ECO Triennial, which "is likely to result in a fragmented and even siloed approach to review, wherein the overall merits of the Company's DI program are challenging to assess." The Department recommended the Commission require Xcel file an amended proposal for DI [in this docket][238] with a complete cost-benefit analysis demonstrating that DI is cost-effective. If the Xcel cannot demonstrate cost-effectiveness on narrow quantitative grounds, then it must provide justification for why it believes that the costs of DI should be allowed for recovery. Require Xcel to make the filing within [180 days][239] of the Commission's order in this docket. (**Decision Option 59**)

ii. Xcel Energy – Reply Comments

In response to the Department, Xcel explained that since it was not requesting certification or cost recovery for DI in the IDP it did not believe that a cost-benefit analysis was appropriate at this time. As stated in other areas of the IDP, Xcel's view is that cost-effectiveness should be evaluated at the time of a cost recovery proposal. The Company provided three additional reasons why provision of a CBA at this point in time is flawed:

1. The Company already provided a CBA when it originally requested certification of specific DI use cases in the most recent rate case, and we will continue to support our future requests for cost recovery of specific DI use cases with a CBA
2. Since DI provides the possibility for a broad range of future use cases, the Company does not have the necessary information about costs and benefits for all these potential DI use cases and would therefore not be able to create a CBA
3. Providing estimated cost information prior to going through a competitive sourcing process can impact the Company's ability to secure favorable pricing, as vendors will have access to our estimated costs prior to finalizing any contracts.

---

[237] Decision In the Matter of Xcel Energy's Program Modification Request Filed April 12, 2024, Docket E,G002/CIP-23-92, June 11, 2024, p. 5-6

[238] The Department did not a location for such a filing, Staff has used the current docket as a placeholder.

[239] The Department did not include a timeline for such a filing, Staff has used 180 days as a placeholder.

Accordingly, Xcel recommended the Commission not adopt the Department's recommendation to file a CBA.

iii. Staff Analysis

Staff agrees with the Department that Xcel's approach to approval of DI will make the overall merits difficult to evaluate. However, Staff is not persuaded that simply requiring Xcel to make a supplemental CBA filing in the present docket will solve these concerns as it would still be disconnected from a prudency review and cost recovery proposal. Staff believes that the technologies brought by DI have the potential to enhance Xcel's optimization of the grid, but there has not been an opportunity for the Commission to fully evaluate and consider the entire scope of benefits and costs associated with DI and how it fits in with the Company's other grid modernization investments.

Staff's understanding from the Commission's July 17, 2023 Order is that Xcel would resubmit DI as a certification request with this IDP, however now the Company is indicating it will seek cost recovery in a future, unspecified proceeding but proceed to roll out programs in the meantime. It is unclear whether the Company plans to seek Commission approval for any aspects of the DI programs before they launch, which is somewhat concerning to Staff given specificity of data DI can collect about customers and their lives. Staff is not convinced that including DI in a future rate case would give the Commission the record it needs considering the scope of other issues present in a rate case. Staff does not have a recommendation at this time on how to proceed, but suggest the Commission discuss with Xcel and the Department how best to get a better roadmap of DI's rollout and cost recovery.

D. Integrated Volt-Var Optimization (IVVO)

Xcel stated that it does not consider IVVO in the public interest.[240]

Xcel stated that the "concept of voltage/VAR management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly – and to deliver power at an optimal power factor to minimize system losses."[241] IVVO is an advanced application of ADMS that can optimize that VAR device management and allows voltage to be monitored along the feeder and select end points rather than just at the substation which allowed the voltage at the substation to be lowered "to achieve a variety of operational outcomes" and achieve general efficiency gains.

Xcel stated that IVVO has been presented to the Commission several times since 2015 and included a certification request in its 2019 IDP. Xcel relayed that most commenters were opposed to certification of all of their requested investments including IVVO. In their prior proposal, Xcel offered to deploy IVVO at 13 substations throughout Minneapolis and Saint Paul and believed that it would a achieve a 1% energy savings but indicated that the benefit-cost ratio (BCR) was less than 1, where costs outweighed the benefits. Xcel found that the four quantifiable benefits of this proposed deployment were 1) a reduction in energy consumption

[240] Xcel Energy, 2023 IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 28 (PDF p. 28)
[241] Xcel Energy, 2023 IDP Part 2 of 3, Appendix B1, November 1, 2023, p. 28 (PDF p. 28)

by flattening out the voltage profile, 2) a reduction of distribution electrical losses, 3) avoided capacity costs, and 4) carbon emissions reductions.

Xcel stated that since 2019, the case for IVVO has diminished due to the potential benefits being lowered as electrification progresses, load increases, and as customers adopt more energy efficient devices and EVs. Xcel specified that there is a load and voltage relationship called "CVR factor" and energy efficient devices will have a low or negative CVR factors are less sensitive to voltage changes and will therefore benefit less from IVVO. With these trends in place, and with a customer base that is sensitive to bill increases, Xcel did not believe IVVO is not in the public interest and should not be pursued at this time.

i. Fresh Energy – Initial Comments

Fresh Energy believed that Xcel should reconsider whether IVVO is in the public interest. Fresh Energy cited other utilities that use IVVO as a cost-effective energy efficiency measure including Ameren and Commonwealth Edison in Illinois as well as PSCo, Xcel's Colorado operating company. Fresh Energy stated that PSCo includes IVVO in its energy efficiency portfolio which obtains 330,000 MWh of annual energy savings and a 44 MW demand reduction.

Fresh Energy requested the Commission require Xcel to re-evaluate IVVO for its NSP Minnesota service area using the new Minnesota Test for cost-effectiveness and updating its assumption using what it learned through PSCo's experience (**Decision Option 60**).[242] Fresh Energy also submitted that Xcel should identify which feeders are cost-effective under IVVO and to use Xcel's "IDP High" forecast scenario[243] to serve as a sensitivity to benchmark the range of benefits IVVO might have under different potential futures.

Fresh Energy also requested Xcel provide the following in reply comments: data on how responsive specific end users were to IVVO, their impact on the benefits, and what common appliances are relevant to IVVO end users. Fresh Energy also requested Xcel answer whether the Company has investigated how IVVO can help in over-voltage areas with high DER penetrations and the results.[244]

ii. GEC –Initial Comments

GEC argued that Xcel did not provide adequate justification to conclude that IVVO is not in the public interest. GEC believed that IVVO has potential to reduce bills for lower-wealth customers if deployed in a targeted way.[245] GEC requested the Commission require Xcel to reevaluate and refile 6 months after order as well as explore how it can be used in targeted ways within "environmental justice areas". GEC suggested that Xcel identify circuits and substations that will not require expensive modifications and that areas without existing low voltage issues could be targeted and identified from AMI voltage measurements or power flow modeling. (**Decision Option 60**)

[242] Fresh Energy, Initial Comments, March 1, 2024, p. 7
[243] Xcel Energy, IDP Part 1 of 3, Appendix A1, November 1, 2023, p. 57 (PDF p. 112)
[244] Fresh Energy, Initial Comments, March 1, 2024, p. 7
[245] GEC, Initial Comments, March 1, 2024, p. 30

GEC pointed out that while future electrification devices will have lower CVR factors, they are still not zero and should benefit from IVVO and that there is still potential savings with existing equipment regardless of electrification trends. GEC offered that Xcel should reexamine the assumptions it made in their 2019 report, especially the "significant costs for static var compensator devices and supporting software from Varentec" as, GEC cited, "many utility deployments of IVVO have been successful without the deployment of such devices."[246]

GEC offered that IVVO has many of the same requirements as DERMS, such as needing high quality operational models, communication and control capabilities with higher numbers of field resources, as well as automated optimization of equipment states in response to grid constraints. GEC suggested that DERMS will require the same general components but on a larger scale which means that a successful deployment of IVVO could be steppingstone on the way to DERMS and may provide important insight in the process.[247]

iii. Xcel and Participants – Reply Comments

Xcel reiterated its position that it believes the benefits of IVVO are even less than they were in 2019 and does not believe it to be "prudent or in the public interest to pursue IVVO further or to devote any additional time and resources for updated analysis, reevaluation, or investigation."[248]

Fresh Energy and GEC pointed out that Xcel did not provide answers to any of the question they asked in reply comments and merely reiterated that that Xcel does not believe IVVO to be in the public interest.[249] Fresh Energy again cited that PSCo forecasts a 44 MW of demand reduction and 330,000 MWh of annual energy savings which is represented as a 0.6% summer peak demand reduction and 1% reduction of annual MWh usage due to IVVO and emphasizes that IVVO requires no customer action or behavioral change.[250]

Fresh Energy indicated that they did not see any opposition to IVVO as a technology from parties in 2019 and that the disagreement were more focused on the AGIS package overall and the use of certification as a process.[251]

Fresh Energy agreed with GEC that while IVVO may be less effective with future devices and electrification it remains effective with the existing equipment used and should remain an effective tool in areas with older housing stock and slower uptake of new electrification technologies, which also indicates it can be deployed to high-impact areas of the grid.[252]

Fresh Energy supported GEC's decision options regarding IVVO and GEC supports Fresh Energy's decision options as well (**Decision Options 60**).[253]

---

[246] GEC, Initial Comments, March 1, 2024, p. 31
[247] GEC, Initial Comments, March 1, 2024, p. 32
[248] Xcel Energy, Reply Comments, March 22, 2024, p. 50
[249] GEC, Reply Comments, April 12, 2024, p. 18
[250] Fresh Energy, Reply Comments, April 12, 2024, p. 3
[251] Fresh Energy, Reply Comments, April 12, 2024, p. 3
[252] Fresh Energy, Reply Comments, April 12, 2024, p. 4
[253] GEC, Reply Comments, April 12, 2024, p. 18; Fresh Energy, Reply Comments, April 12, 2024, p. 4

Minneapolis and the Department also supported requiring Xcel to evaluate feeders for which IVVO is cost-effective under the new Minnesota CB Test and the updated assumptions informed by Public Service Company's experience with IVVO and that the analysis should consider forecasts for EV adoption, building electrification, and distributed generation adoption.[254] (**Decision Option 61**)

Staff notes that Fresh Energy filed a supplementary comment on April 30, 2024.[255] The comment summarized a DOE report: *Innovative Grid Deployment Liftoff Report,* which identified pathways to accelerate deployment of grid technologies and applications on existing distribution systems. Fresh Energy stated the report found that IVVO is economically viable in 70% of use cases and that the average savings were 3.7% with a floor of 1% savings and ceiling of 6.4% savings. The report also stated that IVVO can also enhance energy justice and equity for communities today through these savings. Fresh Energy stated that this report substantiates their positions and reiterated their request to direct Xcel to re-evaluate IVVO for its Minnesota service area.

iv. Staff Analysis

Staff believes that reevaluating IVVO using the Minnesota Test for cost-effectiveness with up-to-date data and new considerations is in the public interest. Staff agrees with Fresh Energy that Xcel can use its experience to offer insights for this reevaluation. The DOE report substantiates the reasons for a reconsideration as well. Staff is also interested in GEC's finding that other IVVO has been implemented by other utilities without needing to make more expensive upgrades to the distribution system and that Xcel may be able to do this as well by targeting specific areas of the grid using AMI measurements. Staff supports both GEC's and Fresh Energy's recommendations regarding IVVO (**Decision Option 60**).

E. FLISR

The Department continues to recommend metrics to evaluate the impacts of spending on Xcel's Fault Location Isolation and Service Restoration (FLISR). FLISR installation began in 2021 on select feeders and will continue through 2027 with functionality available to Minnesota control centers beginning in 2023.[256]

The Company expects that, "FLISR will transform outages that would have been sustained outages into momentary outages" and "minimize widespread extended outages on the system." However, the Company expects CAIDI performance to decline, "when the outages are more heavily concentrated on problems that take a longer time to fix."[257]

In recognition of these expected benefits, the Commission approved recovery of 2022-2024 costs in Xcel's rate case, but also adopted a version of the Department's proposed performance metrics and reporting. While future FLISR cost recovery is not contingent on reliability improvements or other FLISR benefits, the Company was instructed to include in its 2024

[254] City of Minneapolis, Reply Comments, April 12, 2024, p. 1
[255] Fresh Energy, Letter, April 30, 2024, p. 1-2
[256] Xcel Energy, Reply Comments, March 22, 2024 p. 20
[257] Xcel Energy, 2023 SQSR Annual Report, April 1, 2024, Docket 24-27, Attachment J, p. 1-2

Safety, Reliability, and Service Quality (SRSQ) report data, "on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department."[258]

When initial comments were filed in the instant docket Xcel had not yet filed its SRSQ report. Therefore, in the instant proceedings, the Department reiterated its rate case proposal and Commission Order for an annual report of SAIDI, SAFI, and CAIDI for circuits with FLISR installed. More, the Department explained that evaluation of, "overall reliability improvement programs, will best be served by Xcel providing granular FLISR reliability impacts."[259]

In response, Xcel stated confirmed it planned to submit data in response to the Commission's Order in its 2024 SRSQ filing but felt that "The Commission Order does not require the Company to report any of this information in the IDP, and we believe the best place to discuss and potentially provide any additional reliability metrics is in the Annual Service Quality filing." More, the Company explains that reporting data at the feeder level is more appropriate for assessment of FLISR performance.[260]

The Commission has now received Xcel's 2024 SRSQ filing in which the Company explained that it was unable to comply with Commission's Order.[261] The Company said, "As of the end of 2023, we have 95 devices installed on 54 feeders operating in 'Local Mode'. There are 45 devices installed on 28 feeders operating in 'Open Loop Mode'. Currently we do not have any feeders in 'Closed Loop Mode'. It is only in 'Closed Loop Mode' that we are able to track the reliability performance metric required by Order Point 27(a) of the Commission's July 17, 2023 Order, and we do not yet have any feeders operating in 'Closed Loop Mode.' To reach Closed Loop Mode status will require additional experience and confidence that the technology is working as intended, as it will result in changes to management work practices around fault isolation and restoration. We anticipate having feeders in 'Closed Loop Mode' by the end of the fourth quarter of 2027."[262]

In its reply comments made after the Company's SRSQ report was received, the Department reiterated its recommendation that, "the Commission articulate the requirement that Xcel include a report of reliability performance for circuits equipped with FLISR, consistent with the Department's recommendations in the last general rate case."[263] (**Decision Option 61**)

i. Staff Analysis

For clarity, Staff provides the Order points related to FLISR reporting from the Commission's July 17, 2023 Order in Xcel's rate case:

---

[258] July 17, 2023 Order in Docket 21-630, paragraph 27(a)
[259] Department, Initial Comments, March 1, 2024, p. 37. See also July 17, 2023 Order in Docket 21-630, paragraphs 22-27
[260] Xcel Energy, Reply Comments, March 22, 2024 p. 40. Reference to July 17, 2023 Order in Docket 21-630.
[261] Reference to July 17, 2023 Order in Docket 21-630
[262] Xcel Energy, 2023 SQSR Annual Report, April 1, 2024, Docket 24-27, Attachment J, p. 13
[263] Department, Reply Comments, April 12, 2024, p. 18

27. Prior to seeking future cost recovery for any incremental FLISR investments, Xcel must propose a mechanism by which to base cost recovery for FLISR investments on reliability improvements:

a. Xcel must track and report, beginning in its next Service Quality, Safety, and Reliability report due April 2024, on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department, indicating in the Company's safety, reliability, and service quality filings which circuits have been equipped with FLISR. Allow Xcel to modify the requirements on circuit level performance reporting in its annual Service Quality, Safety, and Reliability reports to align with the Department's recommendation.

b. Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.

The Commission's Order is clear that the location for granular FLISR reporting is in the Company's SQSR docket, which this year is filed in Docket 24-27. The Company provides circuit/feeder level metrics on reliability metrics along with system specific data as an attachment to the report. The data includes normalized and non-normalized SAIDI, SAIFI, and CAIDI data along with the causes of customer minutes out (vegetation, storm, animal, etc.) Reporting in the IDP is limited to the FLISR budget spending and a summary of reliability results.

While there is limited FLISR data in the current IDP and SQSR reports, that is likely because the Company is in the early days of deployment and does not have measurable results yet. Staff does not believe it is necessary to file granular FLISR data in the IDP.

However, Staff believes it would be useful for Xcel to tell the Commission when it expects to be able to report FLISR performance data. The Company has given the 2027 completion date for its FLISR installation and that feeders in 'Closed Loop Mode' specifically will be installed by the end of the fourth quarter of 2027; however, the Company has not explained if, in the interim, any reporting of the information ordered by the Commission will be available.[264]

Staff also notes that it may be useful for the Department, Staff, and Xcel to have an informal conversation before the next SQSR reports are filed about how to incorporate FLISR data into the existing spreadsheet with circuit/feeder level reliability data.

F. Technical Planning Standard

Staff provides a brief procedural background on the recent Technical Planning Standard (TPS) proceedings:

---

[264] July 17, 2023 Order, Docket 21-630, ordering paragraph 27a, "Xcel must track and report, beginning in its next Service Quality, Safety, and Reliability report due April 2024, on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department, indicating in the Company's safety, reliability, and service quality filings which circuits have been equipped with FLISR. Allow Xcel to modify the requirements on circuit level performance reporting in its annual Service Quality, Safety, and Reliability reports to align with the Department's recommendation."

On September 12, 2023, Minnesota Solar Advocates (MSA) filed a Formal Complaint against Xcel Energy (Xcel or the Company) opposing Xcel's use of its Technical Planning Standard (TPS).

On February 27, 2024, the Commission issued its Order dismissing the Complaint without prejudice based on a unanimous (4-0) decision made at the December 14, 2024, agenda meeting (Order). The Order also tasked Xcel with hosting informational stakeholder meetings with relevant and interested parties on the justification and decision-making behind the Company's implementation of the TPS, including options to apply the standard more granularly and set aside a smaller buffer.

On March 8, 2024, MSA filed a petition for rehearing regarding the Order dismissing the Complaint. On March 18, 2024, Xcel filed an answer to the petition for rehearing. The Commission heard the petition on April 18, 2024 and dismissed the petition via Commission Order on April 26, 2024.

On May 24, 2024, MnSEIA filed an appeal asking the Minnesota Court of Appeals to review the Commission's dismissal of MSA's complaint related to the TPS. That appeal is currently pending.

ii. Participant Comments

GEC notes in their initial comments that the TPS is likely to and likely has significantly reduced available hosting capacity and that is conceivable "that some of the investments and projects proposed in the IDP, such as proactive hosting capacity upgrades, are higher than they would be if the TPS were not being applied."[265] GEC also points to the Commission's February 27, 2024 Order that spoke to potentially modifying the TPS such as making it be applied more granularly to indicate that the TPS does not seem to be solidified into its current form and that Xcel's own comments in the IDP filing also suggest this as well.

GEC sees several intersections between the TPS and the IDP and urges the Commission to "continue its investigation" into the TPS,[266] including its intersection with the IDP, and answer at a minimum the following questions: (1) Which IDP projects and programs are impacted by the TPS, such that the associated investments are higher than they would be without the TPS?; and (2) Is it just and reasonable to allow full cost recovery of investments that are inflated by application of the TPS?[267] (**Decision Option 63**)

CEEM states that they want greater insight from Xcel and request the Commission require Xcel explain[268]: (1) if Xcel expects additional load growth, why does it need to reserve capacity? (2) What are the assumptions and calculations used by Xcel to arrive at the hosting capacity number? (3) What off-the-shelf and innovative technology is Xcel actually using in its planning and calculations so as to maximize the use of DERs and minimize spending for new equipment? (**Decision Option 64-66**).

iii. Staff Analysis

[265] GEC, Initial Comments, March 1, 2024, p. 52
[266] Note that the Commission chose not to investigate the TPS in its February 27, 2024 Order
[267] Grid Equity Commenters, Initial Comments, March 1, 2024, p. 52
[268] Clean Energy Economy Minnesota, Reply Comment, April 12, 2024, p. 9

Staff would like to reiterate what the Commission has relayed in its February 27, 2024 Order that the Commission "will continue to scrutinize the Company's actions on a case-by-case basis to ensure reasonable outcomes consistent with applicable law" and "that the Company's reasonable application of the standard to individual projects remains within the Commission's purview."[269]

9. Non-wires alternatives

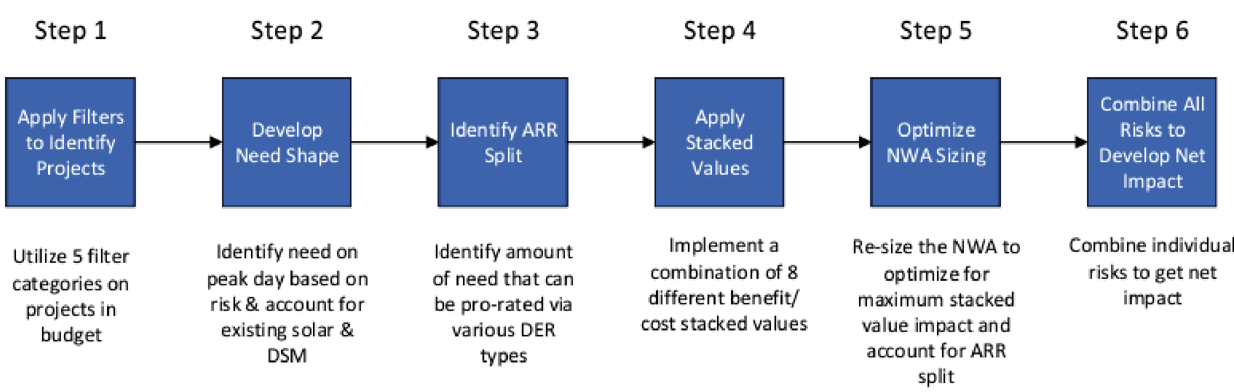
IDP Filing Requirements Section 3.E requires Xcel to conduct a Non-Wires Alternatives (NWA) analysis for upcoming distribution systems projects that have a total cost over $2 million. NWA use non-traditional solutions, such as battery storage, distributed solar, energy efficiency, and demand response, to defer or avoid traditional investments such as transformer upgrades or the construction of a new feeder.

In its 2023 IDP, Xcel analyzed 16 upcoming distribution projects which had to meet the following criteria to go through the NWA analysis:

- Project Type: Capacity
- Timeline: Year 3+
- Project Cost: >$2 million
- Risk Type: Non-Network Substation and Non-Single Bank Substation
- Risk Size: Annual Hours at Risk < 5,840
- Risk Quantity: ≤5 Risks[270]

Xcel follows a six steps process for its initial NWA screen, depicted in Figure 19 below

Figure 19: Initial NWA Screen Process[271]



**Note – in this context ARR stands for "Avoided Revenue Requirement"*

One important component to the Company's NWA analysis is the calculation of the "Avoided Revenue Requirement Split" (ARR split). With the ARR split, Xcel proposes to compensate NWA developers a pro-rated amount based on the number of hours of load reduction services the project would provide. In practice this means the actual cost to install the DER would be larger

[269] February 27, 2027 Order, Docket 23-424, p. 5
[270] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 8 (PDF p. 186)
[271] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 7 (PDF p. 193-194, 202-203), Figure F-2

than what is represented in its NWA analysis, with the Company contributing only the portion of the "ARR split" that would contribute towards the need for the NWA solution.[272]

For its 2023 NWA analysis Xcel made changes to its process. First, in line with the Commission's Order from the Company's 2021 IDP, Xcel used two discount rates to evaluate NWA projects: the weighted average cost of capital (WACC) and the societal discount rate. The Company found that the results using both discount rates were very close, with less than $100,000 in difference in each case. Going forward, Xcel requested to only use the WACC as that is the most common discount rate used by the Company in other proceedings.[273] Second, the Company introduced a "forecast uncertainty margin" to account for variances in actual future load growth, especially at the more granular feeder level where predicting the exact need years in advance can be imprecise. This uncertainty margin has resulted in the Company sizing up NWA solutions to account for unanticipated load growth.[274]

Out of the sixteen NWA projects analyzed in 2023, Xcel found that three had a positive Incremental Net Impact, which is one potential indication the project may be cost effective. Table 16 summarizes the three projects.

[272] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 15-16, 24-25 (PDF p. 186)
[273] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 26 (PDF p. 204)
[274] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 28 (PDF p. 206)

Table 16: 2023 Feasible NWA Candidate Projects – Results Summary[275]

	Reinforce Parkers Lake PKL065[276]	**Reinforce Twin Lakes TWL065**[277]	**Reinforce Twin Lakes TWL078**[278]
Traditional Solution[279]	Upgrade feeder capacity by installing parallel cables in duct	Upgrade feeder capacity by installing parallel cables in duct	Upgrade feeder capacity by installing parallel cables in duct
Cost of Traditional Solution[280]	$3,700,000	$2,500,000	$3,500,000
NWA Solution	New energy storage and new solar PV systems at strategic locations to mitigate risks	New energy storage and new solar PV systems at strategic locations to mitigate risks	New solar PV systems at strategic locations to mitigate risks
Incremental Solar Capacity	8.6 MW	8.6 MW	7.1 MW
Incremental Storage Capacity	1.13 MW/2.45 MWh	0.17 MW/0.29 MWh	-
Total Benefit	$1,780,292	$1,660,240	$1,999,154
Total Cost	$(656,415)	$(595,167)	$(672,370)
Net Impact (Cost of NWA Solution)	$1,123,876	$1,065,072	$1,326,783

All three potential NWA projects have in service dates of 2028, as such Xcel explained it will run the analysis again as part of its annual update before taking next steps. If the Company determines that the projects remain viable, it will disclose next steps in its 2024 IDP Annual Update filed November 1, 2024.[281]

i. <u>Participant Comments</u>

Fresh Energy questioned whether using an "ARR split" would result in developers bidding into any RFPs for potential NWAs, pointing out that Xcel Colorado (PSCo) had an unsuccessful NWA solicitation in 2023 where it received zero bids. Accordingly, Fresh Energy requested Xcel provide additional information on the "ARR split" and developer willingness to engage in NWA development with this type of cost sharing arrangement in reply comments.[282]

Minneapolis was pleased to see three NWA projects were identified as potential solutions. They requested a comment period to weigh in on any Requests for Proposals (RPFs) prior to the

---

[275] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 31 (PDF p. 209), Table F-4
[276] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 38-40 (PDF p. 216-218)
[277] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 32-35 (PDF p. 210-212)
[278] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 35-37 (PDF p. 212-215)
[279] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 31 (PDF p. 209), Table F-4
[280] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 31 (PDF p. 209), Table F-4
[281] Xcel, 2023 IDP Part 2 of 3, Appendix F, November 1, 2023, p. 41 (PDF p. 219)
[282] Fresh Energy, Initial Comments, March 1, 2024, p. 5-6

Company issuance so there could be "input related to eligible programs and technology solutions and better ensure a variety of solutions are considered."[283] (**Decision Option 69**)

GEC supported Xcel's NWA efforts and emphasized the importance of continuing refinement and consideration of NWA going forward.[284]

The Department alleged that Xcel did not comply with the Commission's filing requirements on NWA as it did not provide full analyses for all 16 identified projects, and only provided in depth analysis for the three projects deemed feasible. The Department also made several other recommendations for how the Company should change future NWA analysis, including:

- Considering NWAs for all non-asset-based distribution system projects such as reliability or mandate projects.[285] (**Decision Option 68a**)
- Reexamining the deferral period and payment structures for NWAs.[286] (**Decision Option 68b**)
- Modifying its initial NWA analysis to account for the potential of incremental energy efficiency and demand response.[287] (**Decision Option 68c**)

The Department urged Xcel to be proactive in issuing the RFP for the NWA projects given long lead times for equipment and other supply chain issues.[288] (**Decision Option 68d**)

Xcel disagreed with the Department's presumption that it did not provide required IDP analysis and provided Table 3: NWA Order Point Compliance on page 34 of its reply comments. The Company did not support any of the Department's other recommended changes and reiterated why it has chosen to conduct its NWA analysis the way it has, in line with its explanations from this and prior IDPs.[289] The Company did not respond to Fresh Energy's requests for additional information about the ARR Split.

Given the Company's lack of response to its questions about the ARR Split and the time-consuming nature of NWA solicitations, Fresh Energy recommend the Commission require Xcel to issue a Request for Information (RFI) "to assess the feasibility of its planned NWA solicitation, including the proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of the Commission's order in this proceeding." Minneapolis made a similar recommendation.[290] (**Decision Option 67**)

ii. Staff Analysis

Staff notes that like many areas of the IDP, NWA has been an iterative process, and one that will continue to evolve. Many of the recommendations from the Department of Commerce were addressed in the Company's overhaul of its NWA process in 2021. In the 2021 IDP, the Department recommended rejecting many of the changes it is now advocating for, stating that

---

[283] Minneapolis, Initial Comments, March 1, 2024, p. 3
[284] Grid Equity Commenters, Initial Comments, March 1, 2024, p. 22
[285] Department, Initial Comments, March 1, 2024, p. 42-43
[286] Department, Initial Comments, March 1, 2024, p. 43-44
[287] Department, Initial Comments, March 1, 2024, p. 44-46
[288] Department, Initial Comments, March 1, 2024, p. 46-47
[289] Xcel, Reply Comments, March 21, 2024, p. 30-35
[290] Minneapolis, Reply Comments, April, 12, 2024, p. 1

"the Company's new evaluation methodology and advances in applicable technologies, are sufficient to require Xcel to identify the most cost-effective NWA solution for ratepayers without the imposition of additional requirements determining the specific technologies or contract lengths to be used to address grid hazards or conditions."[291] The Department did not explain why it has changed its position since the 2021 IDP.

To date Xcel has not offered a Minnesota RFP for a NWA solution, indeed this is the first IDP where the Company's analysis has indicated potential cost-effective projects. Instead of changing Xcel's process and methodology yet again, Staff believes it would be more productive for the Company to gain actual, real experience with an NWA solicitation and project. If that fails to yield results the Commission could then consider reexamining the structure of the NWA analysis. Staff does not recommend adopting any of the Department's modifications at this time. (**Decision Option 68a-d**)

Staff does agree with Fresh Energy and the City of Minneapolis that a RFI prior to issuing a full RFP could be beneficial in helping the Company better understand the current marketplace and developer preferences for NWA project. (**Decision Option 67**)

10. Stakeholder Processes

i. GEC – Reply Comments

GEC noted that multiple participants have proposed stakeholder processes on specific issues. In general GEC supported additional stakeholder involvement as it felt it could enhance transparency and collaboration around contested issues. However, it cautioned that if not done well stakeholder processes can be time and labor intensive without any measurable progress. GEC highlighted best practices for stakeholder engagement from the NARUC report *Public Utility Commission Stakeholder Engagement: A Decision-Making Framework*:

- Use a neutral facilitator (or Commission staff) who has familiarity with the regulatory process.
- Establish clear boundaries, goals, and ground rules with participants.
- Prioritize receiving actionable input from stakeholders to make a decision and clearly communicate this priority to the facilitator.
- Set clean intentions for how stakeholders will contribute and give input to the development of interim and final process products.[292]

ii. Staff Analysis

As GEC noted, multiple parties have recommended additional stakeholder processes to develop complex, technical topics. These include:

- A workshop on proactive upgrades and cost allocation for DERs and electrification
- Development of cost benefit analysis for discretionary distribution investments
- A roadmap and stakeholder engagement before the implementation of a DERMS

[291] Department, Reply Comments, Docket 21-694, April 11, 2022, p. 25
[292] GEC, Reply Comments, April 12, 2024, p. 14-15

- A discussion in the DGWG about flexible interconnection
- Further process to refine Planned Net Load
- Additional discussions on overarching grid modernization progress

Staff reached out to participants in the docket to clarify their positions on the different proposals, which are summarized in Table 17.

Table 17: Positions on Stakeholder Processes[293]

	Upgrades/cost allocation	CBA	DERMs	Flexible Interconnection	PNL	Grid Modernization
Xcel	Two Xcel led stakeholder workshops	Xcel led discussion	Does not support FE/GEC roadmap recs or stakeholder process	Does not support FE/GEC roadmap recs or stakeholder process	No further process on PNL	Does not support Dept proposed process
Fresh Energy	Agree with Xcel proposal or Commission led workshop	Agree with Xcel proposal	Roadmap with Xcel led stakeholder outreach	Roadmap with Xcel led stakeholder outreach, also in DGWG	Open to suggestions, priority is having stakeholder process	
Dep	Discuss in DGWG	Agree with Xcel proposal	Xcel led discussion	Discuss in DWGW	No further process on PNL	Company led discussion
GEC	Further IDP record development and/or PUC led workshop	Agree with Xcel proposal	(1) DERMS Roadmap & (2) Xcel-led stakeholder engagement regarding DERMS/ uses cases or PUC led stakeholder process incorporating DERMS and other issues.	Xcel-led stakeholder engagement regarding Flex IX use case or Address in DGWG	Support FE proposal or requiring broader stakeholder engagement that is not Xcel led	
Mpls	PUC led workshop		PUC led stakeholder process incorporating DERMS and other issues.	Address in DGWG	Support requiring broader stakeholder engagement that is not Xcel led	Expand scope of DGWG or create new working group to address grid mod and DG issues
Clean Energy Groups	PUC led workshop					

[293] Based on positions from initial and reply comments, as clarified in the May 31, 2024 Ex Parte Communication from Commission Staff.

Staff also requested feedback from stakeholders on priorities and resource constraints, which are summarized here:

- OAG: will try to participate in stakeholder processes the Commission orders, but likely would focus on cost allocation issues.
- Fresh Energy: upgrades and cost allocation could most benefit from a formal process. Suggest instead of multiple one-off meetings, either Xcel or the Commission host a full 1-day meeting on a variety of topics identified above. Have the resources to participate in one formal processes and a couple informal processes
- Department: Recommended using the DGWG where possible. Other priority is for a workgroup on cost benefit analysis, with the goal to establish a standardized CBA framework for grid modernization investments in Minnesota.
- Xcel: important to have clear goals and objectives for any stakeholder workshops, workshops before the 2023 IDP took over 700 labor hours to prepare and execute. If more workshops are ordered, Company will likely need to increase staffing resources.
- GEC: DERMs/FI is a priority, recommend targeted outreach on specific topics to minimize stakeholder fatigue.

Staff appreciates stakeholder feedback on resources and priorities for future processes. Taking all feedback into account, Staff makes the following comprehensive proposal for additional stakeholder engagement out of the IDP. Staff notes that this aligns with recommendations from prior sections above and includes Staff recommendations for clarifying distribution data reporting and modifications of filing requirements that were discussed in the Joint Briefing Papers.

1. A Commission Staff-led process on cost allocation and proactive upgrades, following the format outlined by Xcel in its reply comments. Staff notes that this workgroup could also include consideration of Section 53 of Chapter 126 – S.F. No. 4942, which directs the Commission to initiate a proceeding for distribution system upgrades to accommodate distributed generation at constrained areas of the grid. (**Decision Option 34**)
2. Refer matters related to Flexible Interconnection to the DGWG to investigate whether any changes to MNDIP are required to implement FI. (**Decision Option 54**)
3. Require Xcel to have informal conversations with any interested stakeholders on the following topics, which are in line with Staff recommendations:
    a. Cost Benefit Analysis for discretionary investments (**Decision Option 27**)
    b. Planned Net Load (**Decision Option 49**)
    c. Distribute Energy Resource Management System (**Decision Option 55**)

    If the Commission does not adopt recommendation on CBA, DERMS, or PNL that require further record development, they would not need to adopt those suggestions.
4. A Commission led initiative to develop a comprehensive list of existing distribution data that exists and proposal for any additional data. (**Decision Option 33**)
5. An informal Commission led effort to modify filing requirements related to beneficial electrification and budget category reporting. (**Decision Options 15 and 17**)
6. At the conclusion of informal processes listed in parts 3 through 5, have a half- or full-day Commission Staff-led meeting to discuss developments, identify areas of agreement

and disagreement, and discuss next steps. Staff proposes that the goal be to have this discussion with enough time for incorporation into the next IDP filing due November 1, 2025. (**Decision Option 70**)

11. Decision Options

- *Staff has consolidated some decision options where stakeholders made similar recommendations.*
- *In some instances, participants did not provide a location or date for the filing of additional information, Staff has added placeholder text.*
- *For transparency, Staff has included an unedited list of recommendations by party as Appendix A to these briefing papers.*

General

The Commission must select DO 1, 2, or 3. It may select DO 4

1. Accept Xcel Energy's 2023 IDP Report as in compliance with IDP reporting requirements. Acceptance of the 2023 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3. (Xcel, Fresh Energy, GEC, Minneapolis)

OR

2. Accept Xcel Energy's 2023 IDP report as in compliance with IDP reporting requirements contingent on the Company making additional filings as noted below. Acceptance of the 2023 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3. (Department)
    a. Find Xcel has not complied with Filing Requirement 3.D.2 and require Xcel to file an amended Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects. (Department, CEEM)

OR

3. Do not accept Xcel Energy's 2023 IDP. (CEEM)

4. Require Xcel Energy to report all DERs and DER forecasts in MW_{ac} in future IDPs. (Staff)

Load and DER Forecast

The Commission may select any combination of Decision Options 5 through 12, or none of the options.

5. In future forecasts, require Xcel: (1) to address any impacts from changes in rate design, in particular the use of time-of-use (TOU) rates, on its IDP forecasts and resulting investment planning; and (2) to continue to refine its incorporation of demand response and load flexibility programs into its forecasts in a more granular manner. (GEC, CEEM)

6. Require Xcel to develop plans to expand load flexibility pilots such that residential customers can opt to participate and be compensated for their load flexibility, taking into consideration recommendations related to their impact on the local distribution system. (GEC)

7. In its next IDP, Xcel shall report on its progress to improve forecasting, including:
    a. Refining its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios.
    b. Presenting an initial C&I beneficial electrification forecast, or if the Company is unable to complete one by that time, the Company shall explain why not and include a detailed explanation of how it is thinking about this forecast, information challenges it raises, and approaches Xcel is considering.
    c. Evaluating the accuracy of LoadSEER forecasts.
    d. Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.

    (Fresh Energy)

8. In future IDPs require Xcel Energy to provide standalone forecasts for demand response, load flexibility, and energy efficiency. (Staff)

9. Require Xcel to provide in the next IDP for one of the LoadSEER forecasts:
    a. a complete list of the data sets used in making the LoadSEER forecast, including:
        i. a brief description of each data set and
        ii. an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer);
    b. a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:
        i. the nature of the adjustment,
        ii. the reason for the adjustment, and
        iii. the magnitude of the adjustment;
    c. a discussion of each essential assumption made in preparing the LoadSEER forecast, including:
        i. the need for the assumption,
        ii. the nature of the assumption, and
        iii. the sensitivity of forecast results to variations in the essential assumptions;
    d. an equation showing the LoadSEER forecast model:
        i. for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …
    e. information documenting the LoadSEER forecast's confidence levels including statistical accuracy of the individual variables and overall model=; and
    f. the outputs from the LoadSEER forecast.

    (Department)

10. Require Xcel to provide a comparison of the forecast provided in the IDP to actuals in its next IDP. (Department)

11. Order Xcel to adopt a forecast method that is reviewable by the Department and other parties for the Company's next IDP. (Department)

12. Require Xcel to double the adoption rate assumptions for electric vehicles and rooftop solar in its next IDP to account for IRA funding. (Minneapolis)

Filing Requirement Modifications

The Commission may select Decision Option 13.

13. Modify Xcel Energy's IDP filing requirements to discontinue requirement 3.A.9. (Xcel, Department, Fresh Energy)

The Commission may select Decision Option 14 or 15, or neither. These decision options are explained the Joint Briefing Papers

14. Modify Xcel Energy's IDP filing requirements to amend requirement 3.A.26, 3.A.28, and 3.A.29 to remove the requirement that financial information be reported in IDP-specific categories as follows: (Xcel, Department)

3.A.26 Historical distribution system spending for the past 5 years.~~, in each category:~~ Information shall be reflected in categories consistent with the Company's cost recovery proceedings.

~~a. Age-Related Replacements and Asset Renewal~~
~~b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue~~
~~e. Grid Modernization and Pilot Projects~~
~~f. Projects related to local (or other) government-requirements~~
~~g. Metering~~
~~h. Other~~
~~i. Electric Vehicle Programs~~
~~1) Capital Costs~~
~~2) O&M Costs~~
~~3) Marketing and Communications~~
~~4) Other (provide explanation of what is in "other")~~

~~The Company may provide in the IDP any 2018 or earlier data in the following rate case categories:~~
~~a. Asset Health~~
~~b. New Business~~
~~c. Capacity~~
~~d. Fleet, Tools, and Equipment~~
~~e. Grid Modernization~~

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

3.A.28 Projected distribution system spending for 5 years into the future ~~for the categories listed above~~ in categories consistent with the Company's cost recovery proceedings. ~~itemizing any non-traditional distribution projects.~~

3.A.29 Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Projects shall be reflected in categories consistent with the Company's cost recovery proceedings. ~~Driver categories should include:~~

~~a. Age-Related Replacements and Asset Renewal~~
~~b. System Expansion or Upgrades for Capacity~~
~~c. System Expansion or Upgrades for Reliability and Power Quality~~
~~d. New Customer Projects and New Revenue~~
~~e. Grid Modernization and Pilot Projects~~
~~f. Projects related to local (or other) government-requirements~~
~~g. Metering~~
~~h. Other~~
~~i. Electric Vehicle Programs~~
~~1) Capital Costs~~
~~2) O&M Costs~~
~~3) Marketing and Communications~~
~~4) Other (provide explanation of what is in "other")~~

OR

15. Delegate authority to the Executive Secretary to work with Xcel Energy and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data. Delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on amended filing requirements if one is reached. (Staff)

The Commission may select Decision Option 16 or 17, or neither. These decision options are explained the Joint Briefing Papers.

16. Adopt a new IDP filing requirement requiring Xcel to specifically address how beneficial electrification is anticipated to affect the distribution grid and cost allocation issues thereof. (Department)

OR

17. Delegate Authority to the Executive Secretary to work with Xcel, the Department, and stakeholders to modify the IDP filing requirements to include discussions of the impacts of electrification where appropriate. Delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on amended filing requirements if one is reached. (Staff)

Resiliency

The Commission may select Decision Option 18. This decision option is explained the Joint Briefing Papers.

18. Direct Xcel to develop a suite of metrics to track resiliency, including SAIDI and SAIFI including MEDs, and other metrics to the extent warranted in its 2024 IDP Annual Compliance filing. (Department)

The Commission may select Decision Option 19 or 20 or neither.

19. Require Xcel to propose a set of resiliency performance metrics such as Sandia's that encompass broad system impacts, in addition to SAIDI and SAIFI its 2024 IDP Annual Compliance filing. (Department)

OR

20. Require Xcel Energy to provide a discussion of how it tracks and considers the restoration of critical customer load, such as hospitals and first responder sites during extended outage events in its next IDP. (Staff)

Equity and Energy Justice

The Commission may select any combination of Decision Options 21 through 23, or none of the options.

21. Authorize the Executive Secretary to open a docket to study and consider (1) racial disparities in involuntary disconnections and (2) whether the Commission should institute a moratorium on some or all utility-service disconnections by Xcel until Xcel develops a robust set of measures to eliminate racial disparities in disconnections. (Staff modification of GEC)

22. Reject Xcel's recommendation to isolate consideration of the disparities identified by the Xcel Equity Analysis and the Chan/Pradhan analysis in the SRSQ Docket and affirm that the IDP is the appropriate forum to evaluate and discuss distribution planning solutions to address these inequities. (GEC)

23. In addition to the reporting in its service quality reports and locational reliability map, require Xcel to:
    a. Report in its 2025 IDP the CELI-12 in neighborhoods where analysis by both the Pradhan and Chan Report and the Company has shown a "strong relationship" between CELI-12 and race when the neighborhood has both a high proportion of people of color and older housing stock.
    b. Report in its 2025 IDP the level of disconnections in neighborhoods where analysis by both the Pradhan and Chan Report and the Company has shown "the number of disconnections is higher in identified lower-income areas and increases when the proportion of people of color increases within an income group."
    c. Describe in its 2025 IDP the steps the Company is taking to reduce and eliminate the racial disparities seen in CELI-12 and disconnections in these neighborhoods.

Xcel shall recalculate racial disparities as part of this reporting to identify the level of improvement over time.

(Fresh Energy)

Distribution Budget

The Commission may select any combination of Decision Options 24 through 26, or none of the options.

24. Require Xcel to incorporate both hosting capacity and equity considerations into its distribution budget prioritization process. (GEC)

25. Reaffirm that the Commission will rely on the IDP when reviewing utility distribution investments in rate cases, and that if a rate case proposal is inconsistent with the utility's IDP, then the bar for Commission approval is significantly higher. (GEC)

26. Require Xcel to separate the total "program" and "project" budgets into discrete programs and projects for all Budget Categories in Attachment H, Capital Project List by IDP Category, to the fullest extent possible. (Department)

Cost Benefit Analysis for Discretionary Investments

The Commission may select any combination of Decision Options 27 through 30, or none of the options.

27. Require Xcel Energy to engage in additional stakeholder discussions on approaches to apply CBAs, or a similar type of evaluation, strategically to program-level investments for discretionary projects. (Xcel, Fresh Energy, GEC)

28. In its next IDP, require Xcel to include a discussion of the results of stakeholder conversations about ways to conduct program-level cost benefit analyses for relevant discretionary distribution expenditures. (Fresh Energy, GEC)

29. As part of the stakeholder effort, require Xcel to explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits. (GEC, CEEM)

30. Clarify that Xcel must evaluate applying cost-benefit analyses to program-level investments. (GEC, CEEM, Minneapolis)

*The Commission may select DO 31 **AND/OR** 32, **OR** DO 33, or none of the options. These decision options are explained the Joint Briefing Papers.*

31. Direct Xcel to provide a proposal for reporting on the expected benefits and costs of elective distribution grid investments in its next IDP. This proposal shall specifically address the following:
    a. What is the definition of an elective distribution grid investment?
    b. What cost threshold, if any, should apply to reporting on the expected benefits and costs of elective distribution grid investments in the IDP?
    c. For which metrics will Xcel report expected results for its elective distribution grid investments?
    d. For which metrics does Xcel propose that it be required to report results on an ongoing basis for its elective distribution grid investments?

    (Department)

AND/OR

32. Direct Xcel to provide a proposal for measuring the capacity, reliability, ratepayer, and equity impacts of its distribution grid investments in its next IDP. This proposal shall specifically address the level of granularity at which Xcel will evaluate these impacts for each budget category, indicating for each category whether Xcel plans to measure these impacts at the level of the budget category, program, project, or at some other level of resolution, or not at all, and specifically accounting for the impact of any expected changes to IDP budget categories. (Department)

OR

33. Delegate authority to the Executive Secretary work with Xcel Energy and stakeholders to discuss metrics reported across distribution dockets and delegate authority to the Executive Secretary to approve via notice a stakeholder agreement on metrics reporting if one is reached. At minimum, the proposal and metrics should include the following components:
    a. Reliability metrics such as SAIDI, SAIFI, CAIDI, CEMI, and CELI
    b. Distribution spending by IDP budget categories
    c. Whether there is available hosting capacity for generation or load at the primary system level
    d. Demographic data including race and income
    e. Installed DERs, ECO rebates, DR customers enrolled in programs
    f. Metrics reported at a feeder and/or census block group level

    (Staff)

Proactive Grid Upgrades and Cost Allocation

The Commission may Decision Options 34 or 35, or neither option.

34. Delegate authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel Energy. The stakeholder workgroup may also include Dakota Electric Association, Minnesota Power, and Otter Tail Power if they wish to participate. The Commission sets the following guidelines for the process:
    a. The goal of the workgroup is to develop proposals for proactive upgrades and cost allocation for Commission consideration and possible adoption.
    b. The process does not need to reach consensus but should aim to clearly identify areas of agreement and disagreement to facilitate a Commission decision.
    c. The Commission establishes a goal of completing the stakeholder process by [insert date]. At the conclusion of the process there will be a notice and comment period on any proposals followed by a Commission decision.
    d. Proposals should address, at minimum, the following topics:
        i. How to allocate the costs of proactive upgrades
        ii. How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory
        iii. If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes
        iv. How a proactive upgrade program would integrate with a utility's planned distribution investment programs
        v. How a utility's other capacity programs and changes to distribution standards impact available hosting capacity
        vi. How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption
        vii. Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).

    (Staff)

35. Require Xcel to host two workshops to advance a framework on DER cost allocation and proactive upgrades. The workshops shall include proposals from stakeholders as well as a proposal from Xcel recommending a path forward. Parties will file meeting materials in this docket, and Xcel must include summaries of stakeholder proposals and stakeholder questions in its next IDP, along with a discussion of its own framework or proposal. (Fresh Energy)

The Commission may select any combination of Decision Options 36 through 41, or none of the options.

36. For its Grid Reinforcements Program, require Xcel to report on actual upgrades undertaken under this budget in its upcoming IDPs, such that the Commission and stakeholders can evaluate its deployment. (GEC, CEEM)

37. For its placeholder budget for proactive hosting capacity upgrades, require Xcel to: (1) target areas serving all or primarily residential and small commercial customers; and (2) consider the energy justice implications of its proactive grid investments, including specifically evaluating whether it can target upgrades to improve capacity for new load or hosting capacity within "environmental justice areas" where it has identified relatively low or constrained capacity. (GEC)

38. Require Xcel to consider socializing the costs of such proactive hosting capacity upgrades, targeted to residential and small commercial customers, similar to the treatment of small customer load. (GEC)

39. Require Xcel to provide options, if any, to help distribute costs to interconnect a small residential facility on a saturated feeder including whether a flat interconnection fee, similar to the small solar array fee, has been considered for larger facilities in its 2024 IDP Annual Compliance filing. (Department)

40. Require Xcel to explain the scale and scope of DERs it expects to serve with the $190 million placeholders in its next IDP. (CEEM)

41. Direct Xcel not to include funds for proactive grid upgrades, such as the Grid Reinforcement Program or the Proactive System Upgrades to Increase Hosting Capacity in its rate case until the Commission has adopted a framework on cost allocation and proactive upgrades. (Staff)

CIAC Waiver

The Commission should select Decision Option 42, 43, or 44. If it selects Decision Option 42 or 43, it may also select 45.

42. Approve Xcel Energy's proposed tariff changes waiving CIAC for certain EV customers as outlined in Xcel's June 12, 2024 Letter. (Xcel)

OR

43. Delegate authority to the Executive Secretary to approve the tariff changes outlined in Xcel's June 12, 2024 Letter via notice if no objections are filed within 30 days of the Commission's Order. (Staff)

OR

44. Deny Xcel's proposed CIAC waiver for certain EV customers. (OAG)

45. Require Xcel to track and report on the amount of each CIAC waiver granted to residential customers and the revenues foregone as a result of the waiver and file the data in its Annual EV Reports due June 1 annually. Require Xcel to report the aggregate number and dollar amount of waivers starting with its 2025 IDP. (Staff modification of OAG and CEG)

Grid Modernization

The Commission may select any combination of Decision Options 46 and 47, or neither option.

46. Require Xcel to comply with additional grid modernization filing requirements established by the Commission in its July 17, 2023 Order in Docket E002/GR-21-630 by providing a roadmap of planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs with its IDP. (Department)

47. Delegate authority to the Executive Secretary to (1) expand the scope of the Distributed Generated Working Group (DGWG) or (2) create a new working group to address grid modernization issues. (Department)

Planned Net Load Methodology

The Commission should select Decision Options 48 or 49.

48. Determine the Company's Planned Net Load methodology is reasonable. (Department, Xcel)

OR

49. Require Xcel to refine its PNL methodology by increasing the PV dependability factor for summer-peaking areas. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly PV generation and to PV nameplate capacity. Xcel shall engage parties that commented on PNL in this proceeding as it evaluates seasonal dependability factors and alternative PNL approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed PNL methodology in its next IDP. (Fresh Energy, Minneapolis, GEC)

The Commission should select Decision Options 50 or 51.

50. Do not require Xcel to implement the 15 percent DF_{PV} in the next planning cycle for N-0 risk analysis in the next IDP. (Department, Xcel)

OR

51. Require Xcel to implement the 15 percent DFPV in the next planning cycle for N-0 risk analysis in the next IDP. (Staff)

DERMS and Flexible Interconnection

The Commission may adopt any combination of Decision Options 52 through 56, or none of the options.

52. Require Xcel to demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: (*GEC, the Department, CEEM, Fresh Energy, CEEM)*)
    a. Implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and
    b. Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.

53. Require Xcel to be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators. (*GEC, the Department, CEEM*)

54. Direct the DGWG to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS. (*GEC, Minneapolis*)

55. Require Xcel to conduct robust stakeholder outreach, including specifically with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving), the feedback it received, and how it has addressed it. The filing shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner. (*GEC, the Department, CEEM, Fresh Energy*)

56. Require Xcel to file a detailed roadmap for DERMS deployment that addresses the questions provided in subpart c. Xcel must adequately address these questions before any DERMS investments will be approved. The roadmap and answered questions shall be filed: (*GEC, the Department, CEEM, Fresh Energy*)
    a. In Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner. (*Fresh Energy*)
    b. Prior to Commission approval and Company implementation of any DERMS investments. (*GEC*)
    c. Questions to consider:
        i. What are the alternatives to DERMS?
        ii. What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries?
        iii. Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems?
        iv. How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure?
        v. How will capacity be allocated across new and existing managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered?
        vi. How will prospective applicants understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?

vii. What are the expected deployment and integrations costs for DERMS? What is the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered?

viii. How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?

The Commission may adopt Decision Option 56 and/or 57, or neither option.

57. Address the DERMS use cases and implementation, and potentially other cross-proceeding and cross-utility issues, such as cost allocation through: (*GEC, Minneapolis*)
    a. The DGWG after first expanding the workgroup's scope and changing its name
    OR
    b. The creation of a separate Commission-led working group dedicated to the topic of DERMS and its related investments

58. Require that any working group efforts on DERMS and Flexible Interconnection are facilitated by a neutral party, such as a Commission-led working group, and are otherwise consistent with the GECs' general stakeholder engagement recommendations. (GEC)

Distributed Intelligence (DI)

The Commission may select Decision Option 59, or not.

59. Require Xcel file an amended proposal for DI [in this docket] with a complete cost-benefit analysis demonstrating that DI is cost-effective. If the Xcel cannot demonstrate cost-effectiveness on narrow quantitative grounds, then it must provide justification for why it believes that the costs of DI should be allowed for recovery. Require Xcel to make the filing within [180 days] of the Commission's order in this docket. (Department)

Integrated Volt Var Optimization (IVVO)

The Commission may adopt Decision Option 60 or 61, or neither option.

60. Require Xcel to re-evaluate IVVO for its Minnesota service area (applying the new Minnesota Test for cost-effectiveness and updated assumptions informed by PSCo's experience with IVVO). As part of this analysis, Xcel shall identify feeders where IVVO is most cost-effective, discuss the potential for targeted deployment to these areas and/or in under-resourced communities, and report on its updated evaluation within 6 months of the Commission's Order in this proceeding in the current docket. (Fresh Energy, GEC)

61. Direct Xcel Energy to identify feeders for which IVVO is cost-effective, using the new Minnesota Test and updated assumptions informed by the experience Colorado affiliate (Public Service Company) with IVVO and the Company's forecasts for EV adoption, building electrification, and distributed generation adoption in its 2024 IDP Annual Compliance filing. (Department, Minneapolis)

Fault Location, Isolation, and Service Restoration (FLISR)

The Commission may select Decision Option 59, or not.

62. Require Xcel to include a report of reliability performance for circuits equipped with FLISR, consistent with the Department's recommendations in Docket E002/GR-21-630. (Department)

Technical Planning Standard

63. Require Xcel to answer the following questions in its next IDP: (1) Which IDP projects and programs are impacted by the TPS, such that the associated investments are higher than they would be without the TPS?; and (2) Is it just and reasonable to allow full cost recovery of investments that are inflated by application of the TPS? (GEC)

64. Require Xcel to explain whether energy storage was considered by Xcel as a means by which to address present or future solar DER capacity constrained feeders in the next IDP. (CEEM)

65. Require Xcel to quantify the number, scale and types of DER projects it expects to support with the hosting capacity placeholder in the next IDP. (CEEM)

66. Require Xcel to explain in the next IDP: (1) if Xcel expects additional load growth, why does it need to reserve capacity? (2) What are the assumptions and calculations used by Xcel to arrive at the hosting capacity number? (3) What off-the-shelf and innovative technology is Xcel actually using in its planning and calculations so as to maximize the use of DERs and minimize spending for new equipment? (CEEM)

Non-Wires Alternatives

The Commission may select any combination of 67 through 69, or none of the options.

67. Require Xcel to conduct a Request for Information (RFI) process to assess the feasibility of its planned NWA solicitation, including the proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of the Commission's Order in this proceeding. (Fresh Energy, Minneapolis)

68. In its next NWA analysis, require Xcel to
    a. Require Xcel to provide consideration of NWAs for all non-asset-based distribution system projects.
    b. Reexamine the deferral period and payment structure as it develops NWA solicitations in future IDPs.
    c. Modify its initial NWA analysis to account for the potential of incremental energy efficiency and demand response.
    d. Account for the potential long lead time NWA providers may face in developing the NWA solutions and not delay solicitation for bids from the marketplace. (Department)

69. Require Xcel to file any RFPs for NWA solicitations for Commission approval after a notice and comment period. (Staff interpretation of Minneapolis)

Stakeholder Processes

The Commission may select Decision Option 70, or not.

70. Delegate authority to the Executive Secretary to conduct stakeholder meeting to discuss developments, identify areas of agreement and disagreement, and discuss next steps for the informal process led by Xcel and the Commission outlined in Decision Options 15, 17, 27, 33, 49, and 55 with the goal of having the discussion with enough time for incorporation into the next IDP filing due by November 1, 2025.

Appendix A: Decision Options as Filed

City of Minneapolis

1. Minneapolis supports requiring a cost-benefit analysis for discretionary distribution system investments.
2. Regarding proactive planning investments: Minneapolis recommends that the overarching goal be serving communities equitably and targeting investments where needs are greatest. We offer the following:
    a. Identify hosting capacity service gaps: analyze whether hosting capacity equitably serves all communities and neighborhoods in the service area, including opportunities for rooftop solar, beneficial electrification, and electric vehicles. Invest first in ensuring adequate hosting capacity in historically marginalized areas for planned investments.
        i. This can be accomplished by layering the hosting capacity map with equity indicators as done with Pacific Power's Distribution System Planning Map.
        ii. Non-wires alternatives (NWA) should be deployed when possible to address service gaps and grid needs because NWA has the added benefit of reducing energy burden for customers and improving housing quality and local resiliency.
    b. Access to benefits: Consider how DERs and non-wires alternatives could be leveraged to provide more resilient power, energy cost savings, jobs, etc. with a goal of better serving low-income communities and households.
    c. 3. Local Government Goals: Overlay hosting capacity with data obtained from local governments on local climate and energy goals within the DER Scenario Analysis8 to determine where investments may be necessary to support municipal goals and ordinances
3. Support for Xcel's proposed stakeholder work to identify a process for cost allocation and proactive upgrades, as long as it is led by a third party, like the Commission or other neutral party. Allow more extensive engagement than two workshops if necessary to achieve optimal results and broader agreement.
4. Require Xcel to issue a Request for Information regarding its proposed Non-Wires Alternative ("NWA") process to ensure the proposed plan is comprehensive and viable for potential responders to an RFP. Given this will be the first NWA project opportunity under the IDP process, this step may be helpful for identifying if there are any modifications that would be beneficial.
5. Require Xcel to evaluate feeders for which IVVO is cost-effective under the new Minnesota CB Test and the updated assumptions informed by Public Service Company's experience with IVVO. The analysis should consider forecasts for EV adoption, building electrification, and distributed generation adoption.
6. Support for Fresh Energy's recommendation to convene stakeholders to refine Xcel's planned net load methodology for the next IDP so that it better reflects the peak load-reducing impacts of solar if the stakeholder process is led by a neutral third party, such as the Commission.

7. With respect to Flexible Interconnection, support the Grid Equity Commenters' recommendation that the existing Distributed Generation Working Group be a forum in which to have this discussion, and generate agreement on defining this use case and other relevant considerations, which could then be filed in the IDP proceeding.
8. With respect to DERMS, support the Grid Equity Commenters' suggestion that the Commission consider either expand the DGWG scope (and renaming the group) or create a separate Commission led working group to address DERMS use cases and implementation, and potentially other cross-proceeding and cross-utility issues, such as cost allocation.

Clean Energy Groups (CEG)

1. CEGs recommend the Commission not relitigate the merits of the CIAC waiver at this time as those were settled in the rate case, and approve the tariff changes.
2. We recommend the Commission require Xcel collect data on waiver amounts and report on those in aggregate as part of the Company's regular data report filings.

Clean Energy Economy Minnesota (CEEM)

1. The Commission should not accept Xcel Energy's IDP until Xcel adopts modifications and recommendations.
2. We urge the Commission to direct Xcel to refile the IDP with all required information on grid-modernization along with a cost-benefit analysis for near term projects.
3. With respect to Distributed Energy Resource Management System (DERMS) and Flexible Interconnection, we request the Commission require Xcel to: (1) demonstrate Xcel's ability to integrate a diverse mix of DERs with the tools available to it today and in the near term, (2) follow a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity, (3) clarify conditions in which Xcel will use Flexible Interconnections involving DER, and (4) conduct substantive engagement with DER owners/operators to produce actionable outcomes.
4. CEEM respectfully requests the Commission require Xcel to (1) address impacts from rate design changes on its IDP forecasts and the effect of those changes on its investment planning, (2) incorporate load flexibility programs in its forecasts along with greater particularity, (3) explain whether energy storage was considered by Xcel as a means by which to address present or future solar DER capacity constrained feeders, and (4) quantify the number, scale and types of DER projects it expects to support with the hosting capacity placeholder.
5. To properly address this issue, Xcel should be required to provide additional information for analysis and briefing and address these questions: What industry practices provide the basis for the 15% Dependability Factor? What standards are used to provide the basis for the 15% Dependability Factor?
6. Regarding Solar cited with customer load, solar cited in front of the meter, and energy storage devices: To properly address this issue, require Xcel to provide additional information for analysis and briefing.
7. Regarding Proactive grid upgrades in anticipation of future DER growth: CEEM respectfully requests the Commission require Xcel to: (1) report on actual upgrades to

its Grid Reinforcement Program so the Commission and stakeholders can evaluate its deployment and (2) explain the scale and scope of DERs it expects to serve with the $190 million placeholder.
8. CEEM respectfully requests the Commission to (1) require Xcel to explain "discretionary" spending as well as its methodology for determining cost-benefit and (2) clarify Xcel should apply the cost-benefit analysis to program investments.
9. CEEM respectfully requests the Commission require Xcel to explain: (1) What factors hindered Xcel from studying energy storage? (2) What factors hindered Xcel from studying power control systems? (3) What factors hindered Xcel from studying advanced inverter functions? (4) What factors hindered Xcel from studying DERMS? (5) What factors made it impractical to implement the use of energy storage or power control systems or advanced inverter functions, or DERMS?
10. To provide greater clarity in this matter, the Commission should require Xcel to explain: (1) if Xcel expects additional load growth, why does it need to reserve capacity? (2) What are the assumptions and calculations used by Xcel to arrive at the hosting capacity number? (3) What off-the-shelf and innovative technology is Xcel actually using in its planning and calculations so as to maximize the use of DERs and minimize spending for new equipment

Department of Commerce

1. The Department recommends that the Commission approve Xcel's IDP, but that the Commission require specific modifications.
2. The Department recommends that the Commission aim to clarify the role of the IDP. [New recommendation]
3. The Department recommends Xcel be required to separate the total "program" and "project" budgets into discrete programs and projects for all Budget Categories in Attachment H, Capital Project List by IDP Category, to the fullest extent possible.
4. The Department generally agrees that Xcel's proposed modifications to the IDP Filing Requirements to remove the IDP-specific categories for financial information are beneficial and provide consistency of budget categories across Xcel dockets. This proposal would also align with the Commission's directive in its July 17, 2023, Order. The Department supports the improved alignment of the IDP process with other dockets, including cost recovery proceedings. Furthermore, to facilitate a comparison of IDP filing requirements and budgets across all IDP filings, the Commission should implement these (or similar) revisions in upcoming procedures with other utilities.
5. The Department recommends Xcel provide options, if any, to help distribute costs to interconnect a small residential facility on a saturated feeder including whether a flat interconnection fee, similar to the small solar array fee, has been considered for larger facilities.
6. The Department recommends the Commission adopt a new filing requirement to specifically address how beneficial electrification is anticipated to affect the distribution grid and cost allocation issues thereof.
7. The Department recommends that the Commission direct Xcel to provide a proposal for measuring the capacity, reliability, ratepayer, and equity impacts of its distribution grid

investments in its next IDP. This proposal should specifically address the level of granularity at which Xcel will evaluate these impacts for each budget category, indicating for each category whether Xcel plans to measure these impacts at the level of the budget category, program, project, or at some other level of resolution, or not at all, and specifically accounting for the impact of any expected changes to IDP budget categories. [New recommendation]

8. The Department recommends that the Commission direct Xcel to provide a proposal for reporting on the expected benefits and costs of elective distribution grid investments in its next IDP. This proposal should specifically address the following: a. What is the definition of an elective distribution grid investment?
    a. What cost threshold, if any, should apply to reporting on the expected benefits and costs of
    b. elective distribution grid investments in the IDP?
    c. For which metrics will Xcel report expected results for its elective distribution grid investments?
    d. For which metrics does Xcel propose that it be required to report results on an ongoing basis for its elective distribution grid investments? [New recommendation]
9. The Department recommends the Commission direct Xcel to refile Appendix C of its IDP to include all required information on grid modernization, including cost benefit analyses of near-term projects. Xcel should further be required to make any other necessary modifications to its IDP to reflect the necessary changes to Appendix C.
10. The Department recommends the Commission clarify its requirement that Xcel comply with additional grid modernization filing requirements established by the Commission in Xcel's last rate case by providing a roadmap of planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs with its IDP.
11. The Department recommends that the Commission articulate the requirement that Xcel include a report of reliability performance for circuits equipped with FLISR, consistent with the Department's recommendations in the last general rate case.
12. The Department recommends that Xcel refile its proposal for DI with a complete cost-benefit analysis demonstrating that DI is cost-effective. If the Xcel cannot demonstrate cost-effectiveness on narrow quantitative grounds, then it must provide justification for why it believes that the costs of DI should be allowed for recovery.
13. The Department recommends that the Commission direct Xcel to provide a roadmap for DERMS deployment that addresses the questions raised by GEC in initial comments. [New recommendation]
14. The Department recommends that the Commission direct Xcel Energy to identify feeders for which IVVO is cost-effective, using the new Minnesota Test and updated assumptions informed by the experience Colorado affiliate (Public Service Company) with IVVO and the Company's forecasts for EV adoption, building electrification, and distributed generation adoption. [New recommendation]

15. The Department recommends that the Commission either: (1) expand the scope of the Distributed Generated Working Group (DGWG) or (2) create a new working group to address grid modernization issues. [New recommendation]
16. The Department recommends that Xcel provide consideration of NWAs for all non-asset-based distribution system projects.
17. The Department requests that Xcel reexamine the deferral period and payment structure as it develops NWA solicitations in future IDPs.
18. The Department recommends that Xcel modify its initial NWA analysis to account for the potential of incremental energy efficiency and demand response.
19. The Department recommends Xcel account for the potential long lead time NWA providers may face in developing the NWA solutions and not delay solicitation for bids from the marketplace.
20. The Department recommends that the Commission direct Xcel develop a suite of metrics to track resiliency, including SAIDI and SAIFI including MEDs, and other metrics to the extent warranted.
21. The Department recommends that, Xcel provide in the next IDP for one of the LoadSEER forecasts:
    a. a complete list of the data sets used in making the LoadSEER forecast, including:
        i. a brief description of each data set and
        ii. an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer);
    b. a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:
        i. the nature of the adjustment,
        ii. the reason for the adjustment, and
        iii. the magnitude of the adjustment;
    c. a discussion of each essential assumption made in preparing the LoadSEER forecast, including:
        i. the need for the assumption,
        ii. the nature of the assumption, and
        iii. the sensitivity of forecast results to variations in the essential assumptions;
    d. an equation showing the LoadSEER forecast model:
        i. for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …
    e. information documenting the LoadSEER forecast's confidence levels, statistical accuracy of the individual variables and overall model, and so forth; and
    f. the outputs from the LoadSEER forecast.
22. In addition, the Department recommends that Xcel provide a comparison of the forecast provided in the IDP to actuals.
23. The Department recommends that the Commission order Xcel to adopt a forecast method that is reviewable by the Department and other parties for the Company's next IDP. [New recommendation].

24. The Department recommends Xcel not implement the 15 percent $DDDD$PV in the next planning cycle for N-0 risk analysis in the next IDP.

Fresh Energy

1. Accept Xcel's 2023 IDP as in compliance with IDP reporting requirements.
2. Discontinue IDP Requirement 3.A.9.
3. Xcel shall conduct a Request for Information (RFI) process to assess the feasibility of its planned NWA solicitation, including the proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of the Commission's order in this proceeding.
4. Xcel shall re-evaluate IVVO for its Minnesota service area (applying the new Minnesota Test for cost-effectiveness and updated assumptions informed by PSCo's experience with IVVO). As part of this analysis, Xcel shall identify feeders where IVVO is most cost-effective, discuss the potential for targeted deployment to these areas and/or in under-resourced communities, and report on its updated evaluation within 6 months of the Commission's order in this proceeding.
5. In its next IDP, Xcel shall report on its progress to improve forecasting, including:
    a. Refining its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios.
    b. Presenting an initial C&I beneficial electrification forecast, or if the Company is unable to complete one by that time, the Company shall explain why not and include a detailed explanation of how it is thinking about this forecast, information challenges it raises, and approaches Xcel is considering.
    c. Evaluating the accuracy of LoadSEER forecasts.
    d. Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.
6. Xcel shall refine its PNL methodology by increasing the PV dependability factor for summer-peaking areas. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly PV generation and to PV nameplate capacity. Xcel shall engage parties that commented on PNL in this proceeding as it evaluates seasonal dependability factors and alternative PNL approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed PNL methodology in its next IDP.
7. Xcel shall host two workshops to advance a framework on DER cost allocation and proactive upgrades. The workshops should include proposals from stakeholders as well as a proposal from Xcel recommending a path forward. Parties will file meeting materials in this docket, and Xcel will include summaries of stakeholder proposals and stakeholder questions in its next IDP, along with a discussion of its own framework or proposal.
8. Xcel shall include in its next IDP a discussion of the results of stakeholder conversations about ways to conduct program-level cost benefit analyses for relevant discretionary distribution expenditures.
9. In addition to the reporting in its service quality reports and locational reliability map, Xcel shall:

e. Report in its 2025 IDP the CELI-12 in neighborhoods where analysis by both the Pradhan and Chan Report and the Company has shown a "strong relationship" between CELI-12 and race when the neighborhood has both a high proportion of people of color and older housing stock.27
f. Report in its 2025 IDP the level of disconnections in neighborhoods where analysis by both the Pradhan and Chan Report and the Company has shown "the number of disconnections is higher in identified lower-income areas and increases when the proportion of people of color increases within an income group."28
g. Describe in its 2025 IDP the steps the Company is taking to reduce and eliminate the racial disparities seen in CELI-12 and disconnections in these neighborhoods. Xcel shall recalculate racial disparities as part of this reporting to identify the level of improvement over time.

10. With the filing of its 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner, Xcel shall: (1) provide a detailed roadmap for DERMS deployment that addresses at least the questions in GEC initial comments and (2) conduct robust stakeholder outreach, including with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving, etc.), the feedback it received, and how it has addressed it.
11. Prior to any Commission acceptance of or Xcel implementation of DERMS investments, 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: (1) implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and (2) pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.

Grid Equity Commenters (Initial)

1. Adopt the following modifications and other recommendations prior to accepting Xcel's IDP.
2. Prior to Commission approval and Company implementation of any DERMS investments, require Xcel to:
   a. Demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: (1) implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and (2) pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation, as discussed in more detail in response to Question 16(b)(i).
   b. Require Xcel to be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.

   c. Provide a detailed roadmap for DERMS deployment that addresses the questions provided below in response to Question 16(b)(i). The Commission should ensure that Xcel has adequately addressed these questions prior to approving any DERMS investments.
   d. Conduct robust stakeholder outreach, including specifically with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving, etc.), the feedback it received, and how it has addressed it.
3. Require Xcel to reevaluate IVVO, updating its analysis and assumptions consistent with the recommendations provided in response to Question 16(b)(ii), and refile its updated evaluation within 6 months of the Commission's final order in this proceeding. In particular, the GECs request that the Commission direct Xcel to explore ways in which IVVO could be deployed in a targeted way within "environmental justice areas," as defined in Minn. Stat. § 216B.1691, Subd. 1(e), to reduce customer bills.
4. Require Xcel: (1) to address any impacts from changes in rate design, in particular the use of time-of-use (TOU) rates, on its IDP forecasts and resulting investment planning; and (2) to continue to refine its incorporation of demand response and load flexibility programs into its forecasts in a more granular manner.
5. Require Xcel to continue to refine its PNL methodology, taking into account concerns discussed in response to Question 16(e) regarding the Company's conservative 15% dependability factor, including specifically to consider: (1) increasing its dependability factor, and (2) seasonal and/or otherwise differentiated dependability factors. Xcel should explain in its next IDP any decisions to change or not to change its dependability factor.
6. Require Xcel to incorporate both hosting capacity and equity considerations into its distribution budget prioritization process, as discussed in response to Question 17.
7. Proactive Grid Upgrades
   a. For its Grid Reinforcements Program, require Xcel to report on actual upgrades undertaken under this budget in its upcoming IDPs, such that the Commission and stakeholders can evaluate its deployment.
   b. For its placeholder budget for proactive hosting capacity upgrades, require Xcel to: (1) target areas serving all or primarily residential and small commercial customers; and (2) consider the energy justice implications of its proactive grid investments, including specifically evaluating whether it can target upgrades to improve capacity for new load or hosting capacity within "environmental justice areas" where it has identified relatively low or constrained capacity.
   c. Consider socializing the costs of such proactive hosting capacity upgrades, targeted to residential and small commercial customers, similar to the treatment of small customer load, as discussed in more detail in response to Question 17.
8. Reaffirm that the Commission will rely on the IDP when reviewing utility distribution investments in rate cases; and that if a rate case proposal is inconsistent with the utility's IDP, then the bar for Commission approval is significantly higher.
9. Cost-Benefit Analysis for Discretionary Distribution Investments

   a. Clarify that Xcel should evaluate applying cost-benefit analyses to program-level investments.
   b. As part of the above effort, require Xcel to explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.
10. Continue the Commission's investigation into the TPS, including its intersection with the IDP, and answer at a minimum the following questions: (1) Which IDP projects and programs are impacted by the TPS, such that the associated investments are higher than they would be without the TPS?; and (2) Is it just and reasonable to allow full cost recovery of investments that are inflated by application of the TPS?
11. Require Xcel to develop plans to expand load flexibility pilots such that residential customers can opt to participate and be compensated for their load flexibility, taking into consideration recommendations related to their impact on the local distribution system, discussed further below in response to Question 24.

Grid Equity Commenters (Reply)

1. Reject Xcel's recommendation to isolate consideration of the disparities identified by the Xcel Equity Analysis and the Chan/Pradhan analysis in the SRSQ Docket, and affirm that the IDP is the appropriate forum to evaluate and discuss distribution planning solutions to address these inequities.
2. Take immediate action to address the pressing issue of racial disparities in involuntary disconnections by ordering a study of the costs and benefits of reinstating a moratorium on some or all utility disconnections. The GECs recommend that the Commission order this study now and then rely on it to inform Commission action to consider a moratorium on disconnections until Xcel can develop a more robust set of measures to eliminate racial disparities in disconnections.
3. Related to the GECs' proposal regarding stakeholder engagement on DERMS and Flexible Interconnection, ensure that any working group efforts on these issues are facilitated by a neutral party, such as a Commission-led working group, and are otherwise consistent with the GECs' general stakeholder engagement recommendations in Section III.
   a. With respect to Flexible Interconnection, the GECs suggest that the existing Distributed Generation Working Group (DGWG) could be an appropriate forum in which to have this discussion, and generate agreement on defining this use case and other relevant considerations, which could then be filed in the IDP proceeding.
   b. With respect to DERMS, the GECs suggest that the Commission consider either expanding the DGWG scope (and renaming the group) or creating a separate Commission-led working group to address DERMS use cases and implementation, and potentially other cross-proceeding and cross-utility issues, such as cost allocation.
4. In addition to the GECs' IVVO recommendations, adopt Fresh Energy's recommendation: Xcel shall re-evaluate IVVO for its Minnesota service area (applying the new Minnesota Test for cost-effectiveness and updated assumptions informed by PSCo's experience

with IVVO). As part of this analysis, Xcel shall identify feeders where IVVO is most cost-effective, discuss the potential for targeted deployment to these areas and/or in under-resourced communities, and report on its updated evaluation within 6 months of the Commission's order in this proceeding.

5. Consistent with the GECs' recommendations related to cost-benefit analysis for discretionary investments, adopt Fresh Energy's proposal that Xcel collaborate with stakeholders on developing a benefit-cost methodology for the six specified program categories.

Xcel Energy (reply)

Decline the following:

1. the Department's recommendation for the Company to provide a CBA for each grid modernization project in the five-year action plan;
2. the Department's recommendation to provide a complete accounting of all historical and all anticipated future grid modernization costs with the IDP;
3. the Department's recommendation to refile Appendix C: Action Plans;
4. the Department's recommendations regarding DI investments, including the request to refile the proposal for DI with a complete CBA;
5. recommendations by parties requesting the Company to conduct CBAs for discretionary projects;
6. the GECs' recommendations regarding our implementation of a roadmap for DERMS and for the Company to demonstrate prudency for any DERMS investments in the IDP;
7. the Department's recommendations regarding NWAs, including their recommendation that we be required to consider NWAs for all non-asset-based distribution system projects;
8. the City of Minneapolis' request for a comment opportunity for any NWA RFPs;
9. the Department's recommendation for the Company to separate the total program and project budgets into discrete programs and budget categories; the GECs' recommended changes to require the Company to incorporate equity and hosting capacity considerations into our budget prioritization process;
10. the Department's LoadSEER forecasting recommendations; the City of Minneapolis' recommendation that the Company double our adoption rate assumptions when factoring in IRA funding; the GECs' recommendations for the Company to incorporate rate design, load flexibility, and demand response impacts into future forecasts;
11. the Department's recommendation to have reliability metrics concerning FLISR reported in our IDP;
12. the GECs' request that the Company reconsider the PNL methodology and specifically consider increasing the dependability factor or using seasonal/ differentiated dependability factors;
13. Fresh Energy's and the GECs' recommendation to re-evaluate IVVO;
14. Fresh Energy's recommendation to add requirements to the Company's ECO programs through the IDP process;
15. the Department's request to discuss alternative tariff structures in the IDP.

Respectfully request that the Commission find that the Company is in compliance with the grid modernization filing requirements, is not deficient in our reporting on NWAs, and accept:

16. the Company's proposal to discontinue IDP Requirement 3.A.9. as requested in our 2023 IDP;
17. the Company's proposal to engage in additional stakeholder discussions on approaches to apply CBAs, or a similar type of evaluation, strategically to program-level investments for discretionary projects;
18. our proposed modification to Xcel Energy's IDP filing requirements to remove the requirement that financial information be reported in IDP-specific categories;
19. the Department's conclusion that the Company's PNL methodology is reasonable and accept the recommendation that the Company should not implement the 15 percent DDPV in the next planning cycle for N-0 risk analysis; and the Company's 2023 IDP