414 Nicollet Mall
Minneapolis, MN 55401

March 22, 2024

**—Via Electronic Filing—**

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

RE: REPLY COMMENTS
2023 INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-23-452

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments in response to comments submitted by parties on our 2023 Integrated Distribution Plan submitted on November 1, 2023 in the above-noted docket.

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

Sincerely,

/s/

AMBER HEDLUND
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosure
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Katie J. Sieben | Chair |
| Hwikwon Ham | Commissioner |
| Valerie Means | Commissioner |
| Joseph K. Sullivan | Commissioner |
| John A. Tuma | Commissioner |

IN THE MATTER OF XCEL ENERGY'S 2023 INTEGRATED DISTRIBUTION PLAN

DOCKET NO. E002/M-23-452

**REPLY COMMENTS**

## INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments in response to Comments submitted by Fresh Energy, the Grid Equity Commenters (GECs), the Clean Energy Groups, the City of Minneapolis, and the Department of Commerce working with Synapse[1] (Department) on our 2023 Integrated Distribution Plan (2023 IDP) submitted on November 1, 2023 in the above-noted docket.

Many Comments were submitted on our 2023 IDP, and similar themes and recommendations were made by multiple parties. Accordingly, these Reply Comments address the Comments we received thematically. Additionally, responses to many of the parties' questions can be found in our 2023 IDP filing or in our answers to Information Requests (IRs); we direct parties to previously submitted information as applicable.

The Company also notes that several Commenters made recommendations that are not consistent with the purpose of the IDP. In Docket No. E002/CI-18-251, the Commission provided the planning objectives for the IDP, stating that – among other things – the purpose of the IDP was to provide the Commission with the information necessary to understand our short- and long-term plans for our distribution system, the costs and benefits of specific investments, and a comprehensive analysis of

[1] While the Department's Comments do not state that they engaged Synapse, the Company participated in meetings on the IDP with the Department and Synapse and understands Synapse to be involved in this proceeding.

ratepayer cost and value.[2] The Commission was explicit in stating that their review of our IDP is not a prudency determination of any proposed system modifications or investments.[3] Therefore, the Company continues to view the IDP as an informational filing, and as such, continues to recommend that information that belongs in a prudency review, such as a rate case, is not appropriate for inclusion in the IDP. The Department has historically agreed with this, as provided in their Reply Comments in April 2022:

> *The Department agrees with the Company that utility IDPs are largely informational filings. The Department supports this approach to distribution system planning at this time and for the reasonably foreseeable future.*
>
> *The Department is not proposing a prudency assessment of utility IDPs.*[4]

Several commenters also suggested that information we already report in other dockets should also be included in the IDP. We point out specific instances of this throughout these Reply Comments but would like to make a blanket statement that creating additional requirements in our IDP for topics that have their own docket would be duplicative and inefficient.

In this docket, we have expressed our interest in engaging with stakeholders on two issues: 1) how to conduct Cost Benefit Analyses (CBAs) for program-level investments for discretionary projects, and 2) developing a framework for selecting proactive grid upgrade projects for hosting capacity. We are open to collaborating with stakeholders on these topics and discussing how to engage more stakeholders. We address this further in Section V. below.

The Company believes that, while there will always be improvements and adjustments in the planning process based on new technologies, new information, and evolving industry best practices, our IDP process is well developed and is reflective of many years of learning, refining, and stakeholder input. For example, we have done extensive work and made huge strides in advancing our non-wires alternative (NWA) analysis process since its first iteration in 2018. The NWA screening process began as a comparison of capital costs between a traditional capacity project and an NWA,

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[2] *In the Matter of the Distribution System Planning for Xcel Energy,* Docket No. E002/CI-18-251, ORDER APPROVING INTEGRATED DISTRIBUTION PLANNING FILING REQUIREMENTS FOR XCEL ENERGY (August 30, 2018).
[3]*In the Matter of Distribution System Planning for Xcel Energy,* Docket No. E002/CI-18-251, ORDER APPROVING INTEGRATED DISTRIBUTION PLANNING FILING REQUIREMENTS FOR XCEL ENERGY (August 30, 2018).
[4] *In the Matter of Xcel Energy's 2021 Integrated Distribution Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project,* Docket No. E002/M-21-694, REPLY COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES, Page 2 (April 11, 2022).

where projects that had NWA capital costs that exceeded traditional capacity project capital costs were deemed as not cost beneficial.

The process has improved dramatically since 2018. Our 2023 analysis incorporates a series of additional considerations that the Company applies to perform a more comprehensive assessment of NWAs. These additional considerations include the following:

- Integrating the National Standards Practice Manual as an NWA framework;
- Including a variety of eight key stacked values to highlight the variety of benefits of an NWA;
- Utilizing an Avoided Revenue Requirement (ARR) split concept to reflect general Power Purchase Agreement (PPA)structures in the NWA screening;
- Further developing NWA optimization to ensure projects are feasible;
- Accounting for both the weighted average cost of capital (WACC) and societal discount rates as well as a range of cost-effectiveness; and
- Incorporating a forecast uncertainty margin to ensure NWAs are sized appropriately.

The combination of all these improvements to the NWA process over the past five years illustrates the Company's dedication to NWAs as a technology that can provide real benefit to the overall system and our customers while meeting clean energy goals. In the 2023 IDP filing, for the first time since the NWA process's inception, the Company found NWA projects to be potentially viable during the initial screening. This indicates to us that the changes we have made to the process are more accurately identifying the value that NWAs can provide while narrowing in on the types of NWA projects that are most likely to be cost-beneficial. We will continue to collaborate with stakeholders during our workshops, and we will continue to refine the NWA process to accommodate feedback and make advancements to the process where feasible.

The balance of this reply is organized into 11 sections as follows:

- Equity;
- Grid Modernization Projects;
- Cost-Benefit Analysis (CBA) for Discretionary Projects;
- Non-Wires Alternatives (NWA);
- Proactive Grid Upgrades for Hosting Capacity and Cost Allocation;
- Budgeting Process;
- Reliability and Resilience;
- Forecasting;

- Planned Net Loading (PNL);
- IDP and Integrated Resource Planning (IRP) Alignment; and
- Miscellaneous.

**COMMENTS**

## I. EQUITY

The GECs and the City of Minneapolis provided Comments on the need to incorporate equity considerations into our distribution system planning process. We appreciate the Comments on this issue and agree this is a priority for the Company. The Company's goal is to integrate equity and environmental justice concerns into the design of a broad range of energy and workforce programs, reduce energy burden, enhance equitable access to renewable energy, and broaden participation in energy decisions.

GECs' Comments discussed in general the need to integrate the principles of equity and energy justice into utility planning and decision-making. GECs presented reliability and service quality data from a 2024 statistical analysis conducted by Dr. Bhavin Pradhan and Dr. Gabriel Chan (Pradhan and Chan Study).[5] We discuss these study results in more detail below and also provide some preliminary comparisons to the Company's own analysis on disparities, which will be filed with the Annual Reliability and Service Quality report in Docket No. E002/M-24-27. We also describe the work conducted thus far through the Equity Stakeholder Advisory Group (ESAG), which has over the last 18 months focused on initiatives to reduce energy burden, promote equitable access to renewable energy, and broaden participation in energy decisions. Lastly, we discuss some of the new legislative initiatives and programs that address interconnection for small, residential rooftop systems and community solar garden (CSG) participation.

The Company's environmental justice position statement builds on the definition in Minnesota law[6] as well as the definition used by the U.S. Environmental Protection

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[5] Bhavin Pradhan and Gabriel Chan, "Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area," February 2024, included as Attachment 2 to GECs' Comments.

[6] HF2310, Sec. 3. [116.065] Cumulative Impacts Analysis; Permit Decisions in Environmental Justice Areas.

[6]Minnesota Statutes 2022, section 216B.1691, subdivision 1, as amended in HF7/SF4 (2023). See also HF2310, Subd. 10b, amending Minn. Stat. 2022 Section 115A.03. Environmental justice means: "1) the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies; and 2) in all decisions that have the potential to affect the environment of an environmental justice

Agency (EPA).[7] The Company is committed to consider environmental justice in our energy, climate, and environmental initiatives, and strives to provide meaningful opportunities for affected communities to participate in the process of considering energy, climate, and environmental initiatives that impact them.[8]

## A. Analyses on Equity in the Company's Distribution System

The GECs presented reliability and service quality data from the 2024 Pradhan and Chan Study. Their Comments highlighted potential disparities in three specific metrics: 1) CELI-12,[9] 2) CEMI-6,[10] and 3) involuntary disconnections. In addition, the GECs discussed hosting capacity statistics from the Pradhan and Chan Study.

> Pradhan and Chan analyzed performance metrics and hosting capacity across communities in the Company's service territory with high percentages of people of color and communities that are classified as "disadvantaged" by the Climate and Economic Justice Screening Tool (CEJST) developed by the Council on Environmental Quality.

As directed in the Commission's May 18, 2023, Order,[11] the Company is conducting our own analysis on whether there are equity disparities in our disconnection practices, reliability (CELI-12 and CEMI-6), and participation in low-income programs. Utilizing our Service Quality Interactive Map that identifies key community demographics of ethnicity, race, and income, this study incorporates additional

area or the public health of its residents, due consideration is given to the history of the area's and its residents' cumulative exposure to pollutants and to any current socioeconomic conditions that could increase harm to those residents from additional exposure to pollutants."

[7] EPA's environmental justice definition: "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys the same degree of protection from environmental and health hazards, and equal access to the decision-making process to have a healthy environment in which to live, learn, and work." See Environmental Justice | US EPA.

[8] See Environmental-Justice-Position-Statement.pdf (xcelenergy.com).

[9] CELI-12: Customers Experiencing Lengthy Interruptions, an outage 12 hours or longer within a single year.

[10] CEMI-6: Customers Experiencing Multiple Interruptions, six or more outages within a single year.

[11] May 18, 2023 Order in Docket Nos. E002/M-20-406 and E002/CI-17-401:
Order Point 3: Required Xcel to conduct an analysis that examines whether there is a relationship between poor performance on the five identified metrics displayed on the interactive map and equity indicators. Required Xcel to file this analysis with its next service quality report due April 1, 2024.
Order Point 4: If Xcel's analysis determines there are disparities in any of the five metrics displayed on the map, required Xcel to identify preliminary steps it could take to rectify the disparities and if Commission approval is required, where and when it would expect to file solutions. This should include an analysis of whether modifications to Xcel's Quality of Service Plan are necessary to address any identified disparities. Required Xcel to file this preliminary plan with its next service quality report due April 1, 2024.

explanatory variables in relevant parts of the analysis, such as housing vintage, English proficiency, access to our payment centers, and access to a home computer and internet service. Our study uses a modeling approach that allows the impacts of these different variables to be more clearly distinguished from each other than they are with a linear regression (straight-line relationship) analysis. We provide some high-level, preliminary findings below within our discussion on the Pradhan and Chan Study results. Our full analysis and discussion will be filed on April 1, 2024, in the Annual Reliability and Service Quality report, Docket No. E002/M-24-27.

The Pradhan and Chan Study found that households in CEJST-designated communities, as well as households in communities that have a high percentage of people of color, are more likely to experience an extended outage (CELI-12) in Hennepin and Ramsey counties. In contrast to the Pradhan and Chan Study, our analysis did not show as strong a relationship between long outage duration (12 hours or longer) and the racial composition of the neighborhood. Rather, our analysis found a strong relationship between CELI-12 and race only in neighborhoods that have both high proportion of people of color and older housing stock vintage. We recognize that long, extended outages are disruptive for our customers, but note that it is unusual to experience them – even the highest occurrence cited by the GECs (47.8 per 1,000 households) is less than five percent of households in our service territory. In addition, longer outages often result from strong storms traveling thorough different neighborhoods; therefore CELI-12 may not be the most appropriate metric to measure systematic disparities.

For the metric of repeated outages, the Pradhan and Chan Study found limited disparities in customers experiencing six or more sustained outages per year (CEMI-6). From 2018 to 2022, disadvantaged communities or neighborhoods with a high proportion of people of color – whether located in Hennepin and Ramsey counties or other areas of the Company's service territory – were not any more likely to experience six or more sustained outages than communities with a lower proportion of people of color. In fact, people of color and disadvantaged communities experienced *fewer* incidences of frequent outages in each year from 2018 to 2022, but the differences were not always statistically significant. Our analysis showed similar results as Pradhan and Chan – there is no clear pattern or relationship between race or income and outage frequency. Neighborhoods with higher proportions of people of color were not any more likely to experience multiple outages (CEMI-6) than other neighborhoods using the variables we considered, noted above. Since CEMI-6 reflects reoccurring or repeated reliability issues, we believe it is a more meaningful metric to analyze disparities than CELI-12.

We recognize that even if the likelihood of extended or multiple outages remains small, the impacts of an electrical outage could be greater in disadvantaged neighborhoods that are disproportionately vulnerable to such emergencies.

Our analysis shows similar results as Pradhan and Chan regarding involuntary disconnections – 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. In general, disconnections are correlated with poverty, and – for a variety of deeply entrenched economic and social reasons that are not driven by the energy system – poverty is correlated with race. The Company has improved our efforts to avoid disconnecting customers, such as offering payment arrangements for longer timeframes, up to a year.[12] If a customer is behind on their bills, the Company begins contacting the customer for nine weeks via emails, phone calls, followed by a past due message on the bill, and a disconnection notice prior to a disconnection occurring.[13] With each contact customers are directed to payment options and payment/energy assistance programs. Additionally, we offer discounted energy bills and past due bill forgiveness through established assistance programs such as PowerON, Gas Affordability, Monthly Discount, and Medical Affordability. In 2023, we began a process that automatically enrolls our electric and natural gas customers in the PowerON and Gas Affordability programs after they are approved for the State's Low Income Home Energy Assistance Program (LIHEAP), thus eliminating an additional application step. This provides our customers with direct access to levelized payment plans and arrearage forgiveness for customers who have never applied for our programs. As a direct result of auto enrollment, we received approval to increase the budget of our PowerON program by $11 million to meet our customer needs. While we take these extensive efforts to avoid customer disconnections, we do not suggest that there is nothing more that should or could be done to address disparities on this issue.

The GECs and the City of Minneapolis also commented on equity in hosting capacity and the need to plan grid investments so that adequate hosting capacity is ensured in neighborhoods that have a high percentage of people of color. As indicated in Figure 1 below, the Company's Hosting Capacity Map generally shows more hosting capacity in the Twin Cities Metro Area, which contains the neighborhoods with the highest proportion of people of color. Suburbs outside the Metro Area and rural areas are

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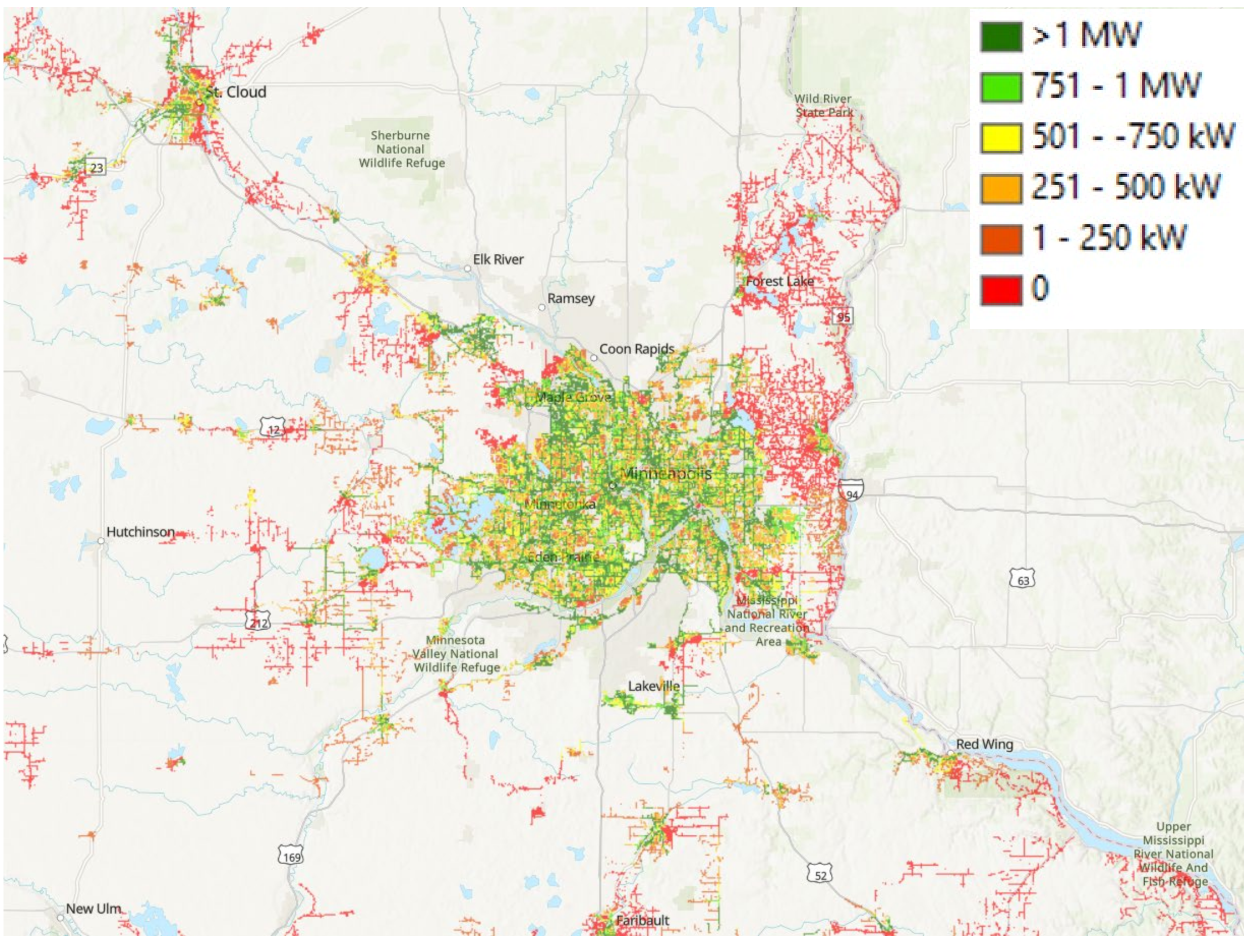
[12] Customers can make an online pay arrangement up to six months through My Account using this link from our Xcel Energy website. [Arrangements | Billing & Payment | Xcel Energy]. If a customer does not have access to a computer or internet, or requires a pay arrangement longer than six months, they may contact our Customer Service Center at 800.895.4999.

[13] This process can be viewed within our May 20, 2022 Variance Petition in Docket No. E002/M-22-233 (Figure 1, page 9).

more frequently lacking hosting capacity, as indicated on the map in red. This is due to the rapid growth of CSGs (currently just over 900 MW) in our service territory, which have exhausted the available hosting capacity on many suburban and rural substations and feeders. Additional capacity cannot be added to these substations and feeders without expensive grid upgrades. The GECs cite similar results from the Pradhan and Chan Study, which shows significantly higher average area hosting capacity (in kW) as well as significantly higher hosting capacity per household in Hennepin and Ramsey counties and in disadvantaged neighborhoods. Hosting capacity is also higher in communities within the top 10 percent of population being people of color.

**Figure 1**
**The Company's Hosting Capacity Map, Showing Available Hosting Capacity by Location**[14]




[14] More information regarding the Hosting Capacity Map can be found in the 2023 Hosting Capacity Analysis docket (Docket No. E002/M-23-466).

The GECs state that the Pradhan and Chan Study shows strong support for the Commission to take action in the IDP proceeding to address persistent system inequities via the Company's IDP.[15] However, we respectfully disagree with this conclusion. The service quality and reliability metrics and performance are discussed extensively in the annual Reliability and Service Quality docket. We believe this is the best place to consider the results of the Pradhan and Chan Study and the results of the Company's study, and to determine carefully what conclusions can be drawn from them, considering the complex nature of inter-related economic, societal, and other factors. As mentioned above, our full analysis and discussion on equity disparities will be filed on April 1, 2024, in the Annual Reliability and Service Quality report, Docket No. E002/M-24-27.

## B. ESAG Discussions on Equitable Access to Renewable Energy

Over the last 18 months, the ESAG, convened under Commission Order in Docket Nos. E002/M-22-266 and E002/RP-19-368, has had robust discussions on how the Company might enhance equity in a range of different programs. ESAG has worked on initiatives to reduce energy burden for our customers who are low-income, Black, Indigenous, or People of Color (BIPOC); diversify the Company's workforce and the broader clean energy workforce; promote equitable access to renewable energy; and enhance procedural justice by broadening participation in energy decisions.[16] In the area of equitable access to renewable energy, our discussions in ESAG have begun from the premise that the existing solar programs have had limited benefit to low-income and BIPOC communities while tending to benefit businesses, governments, and wealthier residential customers – i.e., entities who own a rooftop, have capital to invest in solar, and/or represent most of the capacity subscribed to the CSG program. These are the customers and subscribers whom most solar developers target in their outreach and marketing. A small number of solar developers – including some ESAG members – have actively worked to design solar programs accessible to low-income customers and renters.

Our ESAG discussions on this topic focused on brainstorming new strategies that could increase participation, accessibility, and jobs for low-income and BIPOC customers. ESAG recently developed and voted on a list of 14 strategies for equitable access to renewable energy. One strategy in particular received the greatest support in ESAG's ranked choice voting to prioritize renewable energy strategies:

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[15] GECs Comments, p. 9.

[16] See *In the Matter of Efforts to Advance Workforce Diversity, Inclusive Participation, and Equitable Access to Utility Services for Xcel Energy*, Docket Nos. E002/M-22-266, E002/RP-19-368, Northern States Power Company, doing business as Xcel Energy, COMPLIANCE ANNUAL REPORT (December 29, 2023).

*Support and develop capacity of one or more community-based organizations (CBOs) to provide solar program navigation services: awareness of available programs and incentives, paperwork, translation, up-front financing, assistance evaluating solar offers, assistance navigating interconnection application process.*[17]

Support for this strategy seems to reflect a shared perception that the existing solar options are difficult to navigate and that determining whether they would provide net benefits to a customer or community is challenging. The Company is currently evaluating how we might support implementation of this strategy.

ESAG's list of strategies also included:

- Prioritize projects located in/serving low-income areas for hosting capacity upgrades.
- Create a preference in the interconnection queue process for projects located in/serving low-income areas.

These strategies ranked fourth and fifth, respectively, in the ranked choice voting exercise – after the one mentioned above (developing CBO capacity for solar program navigation), expanding Solar*Rewards, and offering Renewable*Connect for free to customers in a chosen low-income, high energy burden area(s). This shows that while there is interest in those strategies, they are not among the top priorities for ESAG. Additionally, as discussed above, hosting capacity shortfalls do not appear to be a primary barrier to locating projects in low-income or historically marginalized areas. As shown on the hosting capacity map, most areas in red are around the margin of the Metro area, and/or in rural areas, reflecting that available hosting capacity has been largely taken up by CSGs. The primary obstacle to greater low-income participation in solar programs has not historically been hosting capacity shortfalls or interconnection queue constraints, but rather the lack of interest by the majority of solar developers in offering solar to low-income customers.

In their Comments, the City of Minneapolis also urges the Company to consider how distributed energy resources (DERs) and NWAs could be leveraged to provide more resilient power, energy cost savings, jobs, etc. with the goal of better serving low-income communities and households. This has been a focus of the Resilient Minneapolis Project (RMP). While not technically an NWA, RMP will use DERs (solar and batteries) to create islandable microgrids that will support BIPOC community resilience. The two microgrids that the Company plans to build under RMP, pending Commission approval, will be built by a non-local vendor – selected

[17] A summary of the February 16, 2024 ESAG meeting where this was discussed will be filed in Docket Nos. E002/M-22-266 and E002/RP-19-368.

through a competitive Request for Information and Request for Proposals (RFP) process – who has committed to subcontracting portions of the work to local diverse subcontractors. Under the Revised RMP Proposal the Company filed on March 19, 2024, a third microgrid will be built by Renewable Energy Partners, a local certified minority business enterprise, with the Company providing a substantial sub-award from our Grid Resilience and Innovation Partnerships to fund half the overall project cost.

## C. Initiatives to Address Small DER and CSG Participation

Significant barriers that exist for residential rooftop solar participation include home ownership, financing upfront installment cost, and the overall resources needed to navigate various incentive options and the installation process for the photovoltaic (PV) system. As a result, installing rooftop solar is often an unattainable, low priority for low-income customers. Additionally, the Company recognizes the interconnection challenges that residential and other customers experience because of capacity constrained areas in our distribution system, which effectively limit the amount of new DER generation that can be accommodated on the distribution grid and increase the cost of interconnection. However, there are several initiatives underway or already implemented to address barriers for interconnection for small, customer-sited solar projects. The 2023 Minnesota Legislation also addressed low-income customer participation in the CSG program. We discuss these endeavors below.

### 1. *Cost Sharing Program for Small DERs*

In 2022, the Commission approved a cost-sharing program to fund up to $15,000 of upgrade costs, per project, required for interconnecting DER projects up to 40 kW.[18] The Company launched the cost-sharing program on January 3, 2023. The funding for this program comes from a $200 cost-sharing fee that interconnection applicants for small DER projects must pay. We would like to note that this fee is waived for low-income customers. If a feeder is not capacity constrained, most projects up to 40 kW do not need to pay any upgrade costs for interconnection. If upgrades are needed on these non-constrained feeders, they often require a new service transformer and/or service line, which typically costs about $8,000-$10,000. This amount is below the $15,000 threshold and would be paid in full by the cost-sharing fund. In 2023, there were only two applications funded from the program that needed upgrades that exceeded the $15,000 per application cap.[19]

[18] See Docket No. E002/M-18-714, ORDER APPROVING IMPLEMENTATION OF COST SHARING AS MODIFIED (December 19, 2022).
[19] See Docket No. E002/M-18-714, ANNUAL 2023 REPORT (March 1, 2024).

As a result of high levels of interconnected CSGs, distribution grid congestion, and longer interconnection queues, interconnecting DERs on the Company's system has become increasingly complex. If a feeder and/or substation is capacity constrained, the upgrade costs to interconnect any type of DER – including small rooftop solar – are usually cost-prohibitive, as costs can exceed $1 million. To address these complex interconnection barriers, the 2023 Legislation established some significant changes and new programs that impact DER interconnection in H.F. 2310, Article 12, Section 75. As discussed below, many of these legislative changes are interrelated and generally aim to increase solar energy resources, especially small customer-sited projects.

*2. Queue Priority for Small DERs*

The 2023 Legislation directed the Commission to open a proceeding to establish interconnection procedures that give customer-sited DER projects up to 40 kW priority over larger projects in the interconnection queue. Several parties filed proposals on November 1, 2023, in Docket No. E999/CI-16-521, and Comments on those proposals were submitted in January and February 2024.

The Company proposed to adjust the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) to establish a separate interconnection queue for customer-sited applications up to 40 kW (Priority Queue), and to reserve DER capacity specifically for these applications. As explained in that proceeding, we believe that capacity reservation for small projects is critical, as a separate queue alone is unlikely to achieve any longer-term benefits. Without a capacity reservation, additional feeders and substations will continue to become oversaturated with large DERs, ultimately leaving no additional capacity for small DERs to interconnect, unless significant and costly upgrades are undertaken.

In its March 14, 2023 agenda meeting, the Commission voted to allow the Company to establish two administrative queues, which will be evaluated after 24 months. The Commission did not approve the Company's proposal to reserve capacity for small DERs and determined that there is need to develop additional record on this issue in a separate proceeding.

The Commission's February 27, 2024 Order in Docket No. E002/C-23-424 also confirmed that the Company's Technical Planning Standard (TPS) is an engineering judgment which does not require Commission approval for implementation, as the Company must operate our distribution system using sound engineering practices. The Commission stated that it is unreasonable to expect that the Company could effectively, reliably, and safely operate our complex and vast distribution system without technical standards and engineering practices that are designed for that purpose.[20]

### *3. DER System Upgrade Program*

The DER System Upgrade Program, created under Minn. Stat. § 216C.378, will help fund upgrades to the Company's distribution system which will increase available hosting capacity for small DERs in already constrained areas. The law allocated $10 million for such upgrades and required that the funded improvements must maximize the number and capacity of DER projects up to 40 kW. All new hosting capacity created by upgrades must also be reserved for small DER projects. On November 1, 2023, the Company filed our proposed Program Plan, [21] which will need approval by the Department. We proposed to construct system upgrades in six constrained areas[22] and estimated that this will add over 85 MW of available capacity and allow over 2,000 new, small DER projects to be interconnected. The Company proposed traditional upgrade solutions that can be implemented in a timely manner and with high certainty of success, such as adding a second feeder or replacing existing substation transformers. The Company also discussed other innovative solutions in the proposed Program Plan – including energy storage, power control systems, advanced inverter functions, and a distributed energy resource management system (DERMS) – but found them impractical to study and evaluate within the short period required for this funding opportunity, or to practically implement to have an impact on small DERs. Parties' Reply Comments on our proposed Program Plan were filed on March 8, 2024.

### *4. New Low- and Moderate Income (LMI) Accessible Community Solar Garden Program*

For CSGs, one barrier for residential participation has been the contiguous county rule, which requires that the subscribers live near the garden, in the same or adjacent county. It is harder to locate CSGs close to low-income communities because there is a lack of suitable land available. The 2023 Legislation addressed some of the barriers for low-income and residential CSG participation. On January 1, 2024, the Company's

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[20] See *In the Matter of the Formal Complaint and Request for Relief by the Minnesota Solar Advocates*, Docket No. E002/C-23-424, ORDER DISMISSING COMPLAINT, pgs.4-5 (February 27, 2024).

[21] See *In the Matter of the Request for Approval of a Renewable Development Fund for Distributed Energy Resources System Upgrade Program under Section § 216C.378,* Docket No. E002/M-23-458.

[22] These areas are: Chisago substation (serving North Branch, Wyoming, Stacy, Lent, Almelund, and Sunrise); Lowry substation (serving Lowry, White Bear Lake Township, and Minnewaska Township); Northfield substation (serving Northfield, Dundas, Waterford, and Stanton); St. Cloud substation (serving St. Cloud, St. Augusta, and Clearwater); Waterville substation (serving Waterville and Janesville), and Lawrence Creek substation (serving Shafer, Taylors Falls, St Croix Falls, Almelund, Center City, and Franconia).

Solar*Rewards Community Program was closed to new applications, and the LMI-Accessible CSG program administered by the Department was launched.[23] The new non-legacy program requires that the CSG subscriber is an Xcel Energy customer, which makes it easier to locate CSGs because they no longer need to be close to the subscriber pool.

In addition, the LMI-Accessible CSG Program has specific requirements for LMI and public interest participation: at least 30 percent of the CSG capacity must be subscribed to by LMI customers and at least 55 percent of the CSG capacity must be subscribed to by customers who are LMI subscribers, public interest subscribers, or affordable housing providers. Additionally, the bill credit rates are higher for LMI, residential, public interest, and affordable housing subscribers.

## II. GRID MODERNIZATION PROJECTS

### A. CBAs and Cost Information

The Department questioned whether the Company met all IDP filing requirements for grid modernization projects, specifically regarding conducting a CBA for each project in the five-year action plan, providing complete accounting for historical and future costs, and providing adequately detailed information for Distributed Intelligence (DI) investments. The Department also requested that the Commission direct the Company to refile *Appendix C: Action Plans* with all required information.

The 2023 IDP included a detailed discussion and information on grid modernization projects in *Appendix B1: Grid Modernization, Appendix B3: Existing and Potential New Grid Modernization Pilots,* and *Appendix C: Action Plans.*

#### *1. Filing Requirements*

##### a. CBAs for Grid Modernization Projects in the Five-Year Action Plan

The Department suggested the Company has neglected to provide a sufficiently detailed evaluation of the grid modernization investments included in the five-year action plan, including a CBA for each project.

[23] See https://mn.gov/commerce/energy/consumer/energy-programs/community-solar-gardens.jsp.

We have consistently followed the same approach for providing information on grid modernization projects in the 2023 IDP as we used in our 2019 and 2021 IDPs.[24] If a specific project has been fully developed and we have sought approval for it from the Commission (either certification or cost recovery), we have provided detailed information on project objectives, costs, benefits, cost-effectiveness, and timing. However, if we have not submitted a project proposal for Commission approval, we have not provided this level of detail, nor a CBA, with the IDP. In the 2019 and 2021 IDP dockets, no party challenged this approach or questioned our compliance with the filing requirements for grid modernization projects. The Department was the only commenter that suggested we may not have met the compliance requirements for grid modernization projects in the 2023 IDP.

The current IDP filing requirement 3.D.2.k for grid modernization projects reads as follows:

> *For each grid modernization project in its 5-year Action Plan, Xcel [Energy] should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.*

The language in requirement 3.D.2.k is not absolute. We believe the conditional language of "should" instead of "shall" and "best information it has at the time" gives the Company flexibility about whether it is useful to provide a CBA for a certain grid modernization investment. In a legal context, the word "should," expresses a recommendation or suggestion and is used to convey a degree of uncertainty of a future action. Conversely, the word "shall," expresses a mandatory obligation for future action. The scope and details of a project must be developed to a certain level, based on the planning stage and the nature of the investment, before it makes sense to conduct a CBA. Therefore, the Company is in the best position to determine whether a CBA would provide meaningful information for an investment.

By nature, many grid modernization initiatives consist of an ecosystem of related and integrated software tools and a myriad Customer-Facing and Grid-Facing technologies, meaning that for many initiatives it is not feasible to conduct a single CBA. DI and DERMS are an example of this. For these types of grid modernization initiatives, components are strategized and planned at different timelines, and it would often be improper and preliminary to try to estimate their costs and benefits at the same time.

Although we agree that CBAs may provide helpful evaluation of a planned investment, their fundamental implication is that a project is only valuable if it saves

[24] Docket Nos. E002/M-19-666 and E002/M-21-694.

more money than it costs, and for that reason, a CBA is not always the best or only tool to assess investments. Reliance on CBAs for grid modernization projects that are in the early stages of potential investment could encourage overlooking other valid considerations, such as customer preferences, customer satisfaction, and customer convenience/inconvenience.

Finally, while we recognize that parties may want more detail early in the investment planning process, until the Company is ready to seek cost recovery, our estimated costs and benefits may materially differ from those that will be presented in our ultimate cost recovery proposal. Requiring a premature CBA on preliminary project plans would introduce a notable risk that we may be unreasonably held to the CBA's estimates in the cost recovery process or required to try reconciling cost-benefit estimates conducted at different times. Providing a CBA early in the investment planning process would falsely imply a level of precision that does not exist. Additionally, conducting premature analysis that may need to be redone on issues that may significantly change or never materialize is not efficient.

The IDP process is designed to provide the Commission and stakeholders with the information necessary to understand the Company's short-term and long-term distribution system plans. It is not intended to assess the prudency, reasonableness, or cost recovery of our planned investments. The Company believes the practice we have followed since the 2018 IDP filing is appropriate: when an investment is ripe for certification or cost recovery, we will provide all required information with the proposal, including objectives, a CBA, historical costs, future costs, and alternatives analyses.

Additionally, even if a project has been certified by the Commission, the Company must provide detailed cost information when cost recovery is requested. For example, the Commission's July 23, 2020, Order in Docket No. E002/M-19-666 required the following information with any future cost recovery request for Field Area Network (FAN) and Advanced Metering Infrastructure (AMI):

- A discussion of mechanisms that will be employed to maximize cost reductions and minimize cost increases, and
- A demonstration that the utility has thoroughly considered the feasibility, costs, and benefits of alternatives, and that the proposed approach is preferable to alternatives.

The Commission also clarified in this Order that "it is not pre-judging whether costs will be recovered through riders or base rates. Certification will permit Xcel [Energy] to request rider recovery in the future, which the Commission may approve or deny based on the facts available at that time."[25]

Accordingly, we believe we have met the IDP filing requirement 3.D.2.k for grid modernization projects and request that the Commission decline the Department's recommendation that the Company should refile *Appendix C: Action Plans* with a CBA for each near-term project.

b. Accounting of All Historical and All Anticipated Future Grid Modernization Costs

The Department also suggested that the Company should be required to provide a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs in the IDP filing.

This suggestion stems from the Company's most recent electric rate case, where it was discussed in the Department's Direct Testimony[26] and in the Company's Rebuttal Testimony,[27] as well as in the narrative of the Commission's July 17, 2023 Order.[28] However, the specific language recommended by the Department was not included when the Commission adopted Ordering Point 128.[29] The Department's recommendation suggested the following standardized information in all future grid modernization proposals: require a road map with all planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.[30] The Department agreed that the 2023 IDP had met the roadmap requirement and asked the Commission to clarify its additional grid modernization filing requirements regarding historical and future costs established in the last rate case.[31]

The Company continues to believe that the Department's proposed requirements to provide information on all past, planned, contemplated, and future grid

[25] See Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS, Order Point 11 (July 23, 2020).
[26] See Docket No. E002/GR-21-630, Direct Testimony of Ben Havumaki, p. 14-17. (October 3, 2022).
[27] See Docket No. E002/GR-21-630, Rebuttal Testimony of Marty D. Mensen, p. 45-49. (November 8, 2022).
[28] See Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, p. 146-147 (July 17, 2023).
[29] Order Point 128 reads: The Commission adopts the Department's recommended grid modernization filing requirements.
[30] See Docket No. E002/GR-21-630, Direct Testimony of Ben Havumaki, p. 4, 41 (October 3, 2022).
[31] See Department's Comments, p. 35-36.

modernization investments are overly broad. These requirements may not be applicable to each proposal, and, in most cases, it would not be possible for a utility to provide this information, as it would require speculation on the future, which will almost certainly change.

However, we intend to comply with the July 17, 2023 Order to the best of our ability when it is required – when we come forward with a grid modernization proposal. The IDP in and of itself is not a grid modernization proposal. We see a grid modernization proposal to be either a certification or cost recovery request for a grid modernization project. As discussed above, when we come forward with a grid modernization proposal, we will provide the required information to the best of our ability at that time.

As noted throughout this filing, a difference remains between the information that should be provided in an informational IDP filing versus a cost recovery proceeding for a specific investment. We provide detailed actual historical and future budgeted cost information when cost recovery is requested in a rate case or in a rider cost recovery filing.

We respectfully request that the Commission reject the Department's recommendation and clarify that the Company should not be required to provide a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs in every IDP filing.

### *2. CBAs for Current and Planned Grid Modernization Projects*

We discuss here further why it is not reasonable to require a CBA for every near-term grid modernization investment included in the Company's Grid Modernization Plan, as requested by the Department.

*Appendix B1* and *Appendix C* to the 2023 IDP describe the implementation timeline and costs for our major grid modernization projects that have been approved by the Commission. These include:

- An Advanced Distribution Management System (ADMS) that provides grid operators important and necessary visibility and control of increasingly complex distribution grid operations,
- Advanced Metering Infrastructure (AMI) that provides customers with detailed usage information to understand and modify their usage as well as foundational capabilities for the Company to improve its operations and more efficiently implement advanced rates and load flexibility programs,

- A Field Area Network (FAN), which facilitates two-way communications between AMI meters and other smart devices on the distribution grid, and
- Fault Location, Isolation, and Service Restoration (FLISR), which will significantly improve reliability for customers by automating actions on the grid to isolate faults and providing insights to operators that improve outage response efficiency.

As shown in Table 1 (a slightly modified Table 6 from the 2023 IDP),[32] implementation of these projects is either underway or completed. ADMS, AMI, and FAN have been certified by the Commission and the costs are being recovered through the Transmission Cost Recovery (TCR) Rider. The Commission approved recovery of 2022-2024 FLISR program costs as part of our most recent rate case (Docket No. E002/GR-21-630). For each of these four projects, we provided a detailed CBA when the project had progressed to a point where it was fully developed, and we were requesting either certification in the IDP or cost recovery in a rate case. As an example, for FLISR, Order Point 21 of the Commission's rate case Order, found that the CBA we provided for FLISR with our recovery request was reasonable.[33]

**Table 1**
**Grid Modernization Implementation Timeline**

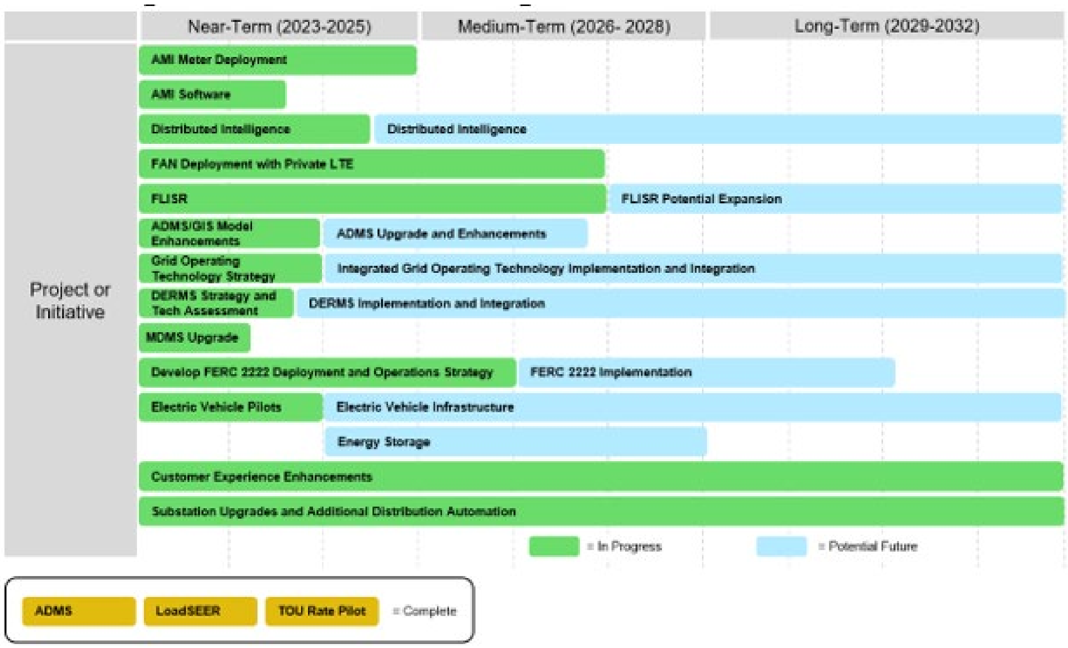
| Program | Implementation Timeline |
|---|---|
| ADMS | Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021. In 2022, we brought all the substations and feeders that are part of the Minnesota system into ADMS, based on current asset information in GIS. As a result, the full Minnesota primary distribution system is depicted in and can be operated from ADMS. Additional data collection, validation, and testing of feeders to support distribution grid operations from the ADMS was completed in 2023. |
| AMI | Meter deployment began in 2022, with anticipated completion in 2025.[34] |
| FAN | The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed. |

[32] Table 1 contains updated information related to ADMS and AMI.
[33] See Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (July 17, 2023).
[34] Since our previous IDP filing, we have begun installing AMI meters in Minnesota. As of March 9, 2024, we have installed 753,000 AMI meters so far.

| | |
|---|---|
| FLISR | Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality will be available to the Minnesota control centers use starting in 2023 on select feeders and will be continued to be expanded to other feeders through 2027. |

In contrast to ADMS, AMI, FAN, and FLISR, our 2023 IDP also discussed several other grid modernization projects that are currently in the early stages of planning. Figure 2 (Figure B1-2 from the 2023 IDP) below provides a near- and long-term illustrative plan – or roadmap – of planned and potential future grid modernization investments.

**Figure 2**
**2023 IDP- Illustrative Long-Term Grid Modernization Plan**




The Department made an overall recommendation that the Company should refile *Appendix C: Action Plans* with all required information on grid modernization, including CBAs for each near-term project.[35] However, several near-term projects in Figure 2 are related to AMI, FAN, FLISR, and ADMS, which have already been certified and are being implemented. The illustrative plan also includes several near-term initiatives that are related to developing strategy for future, such as the "Grid Operating Technology Strategy," "DERMS Strategy and Tech Assessment," and "Develop FERC 222 Deployment and Operations Strategy" Projects. A CBA is not appropriate for these types of strategic initiatives. Similarly, "Customer Experience

[35] Department Comments, p. 35.

Enhancements" and "Substation Upgrades and Additional Distribution Automation" are large placeholder buckets for various types of future investments that have not yet been developed into distinct, concrete projects. The Company believes that a CBA would not be appropriate or provide meaningful information for these types of initiatives. Requesting a CBA for all near-term projects/initiatives displayed in the illustrative roadmap would be premature and, in many cases, not possible particularly for projects still in the planning stage. Therefore, we oppose the Department's recommendation to re-file *Appendix C: Action Plans*.

Our 2023 IDP clearly stated that besides AMI, FAN, FLISR, and ADMS, we have not made proposals for any other grid modernization project and therefore, have not incorporated any new grid modernization investments into a specific timeline, budget, or proposal.[36] When a project is fully developed and we decide it is ripe for a cost recovery proposal, we will include all required information – such as project objectives and description, CBA, demonstration of cost-effectiveness, and alternatives analyses – with the proposal.

We are also concerned that conducting a CBA for a project that is in the early stages of development could provide misleading information and false precision, and therefore inappropriately impact decisions on next steps. For example, projects typically include multiple vendors, and a project may not have progressed to the point where the Company has cost information from the multiple vendors that may be involved. In addition, as experienced especially in the past few years, project costs could significantly increase due inflation, supply chain issues, labor market conditions, and other economic phenomena. Premature CBAs could also interfere with our negotiations with third-party vendors and detract from our bargaining power, and therefore, our ability to secure the best least-cost option for our customers.

We discuss below in more detail why it would be premature to conduct CBAs for DI and DERMS. That discussion generally applies also to other grid modernization projects, which by nature, are often large umbrella initiatives with many distinct sub-projects or use cases.

To summarize, we request that the Commission decline the Department's recommendation that the Company should prepare a CBA for each near-term grid modernization project and refile *Appendix C: Action Plans*.

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[36] A*ppendix C: Action Plans*, p. 6-7.

### *3. CBAs for DI and DERMS*

The Department suggested that the Company should have provided detailed cost information in the 2023 IDP for DI investments and recommended that the Commission direct us to refile our DI proposal with a complete CBA, including a demonstration that DI is cost-effective, to allow for recovery.[37] However, because the IDP and our discussion on DI did not propose any DI investments for certification or cost recovery, we do not believe this detailed information is required at this time.

As we described in *Appendix J: Distributed Intelligence*, DI provides the possibility for a broad range of uses and advancement of technology over time. In that Appendix, we also discussed our current plan for Grid-Facing and Customer-Facing use cases, but we were also clear that we were not seeking Commission approval of our plans at this time. The Company plans to seek recovery of costs to develop the DI products in future cost recovery proceedings.

We believe the Commission should reject the Department's recommendations regarding DI. Each investment's cost-effectiveness should be examined when the Company is seeking either certification or cost recovery in the appropriate proceeding for that type of investment. In addition, we believe that the Department's suggestion that the Company create a CBA for all DI investments suffers from at least three significant flaws. First, 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. Second, 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. Third, 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.

The Department also commented that the Company had not provided sufficiently detailed evaluation of investments for DERMS. As we describe in more detail below, we are taking a measured and use case-based approach to implementing DERMS. As such, it would be premature to provide a detailed evaluation of investments for

[37] Department March 1, 2024 Comments, p. 39. Besides requesting refiling DI with a complete CBA, the Department's recommendation also stated: "If the Company cannot demonstrate cost-effectiveness on a narrow quantitative ground, then it must provide justification for why it believes that the costs of DI should nonetheless be allowed for recovery."

DERMS. In addition, the Company has concerns with providing detailed cost information prior to starting the competitive sourcing process for not only a DERMS itself, but also other resources needed to support the deployment of a DERMS, as vendors will have access to our estimated cost information, which can impact our ability to secure favorable pricing.

When a specific DI or DERMS use case is fully developed, and the Company decides it is ready for a cost recovery proposal, we will include all required information with the proposal.

In summary, we respectfully request the Commission decline the Department's recommendation that the Company be directed to refile its proposal for DI with a complete CBA that demonstrates cost-effectiveness.

## B. DERMS

In Comments, the GECs provided several recommendations regarding our consideration and potential deployment of DERMS, as reflected in our DERMS roadmap presented in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity*.

First, we would like to address the GECs' request that the Company be required to provide certain information in the IDP before Commission approval of any DERMS investments. When we seek approval and cost-recovery for any investment (either certification or cost recovery), we provide detailed information on project objectives, costs, benefits, cost-effectiveness, and timing. As stated throughout these Reply Comments, the IDP does not involve a prudency determination of any proposed investments, including a potential DERMS investment. The Company must show in a separate cost recovery process that all distribution system investments are justified and reasonable, and it is in those separate proceedings that the Company bears the risk that cost recovery may be denied by the Commission.

The GECs also proposed a tiered approach to implementing Flexible Interconnection, DERMS, and Dynamic Hosting Capacity. This proposed approach demonstrates a fundamental mischaracterization of Flexible Interconnection and DERMS capabilities. For instance, while it may be possible to facilitate rudimentary localized, flexible interconnection agreements using smart inverter settings, coordination of multiple DER sites in the future will require more advanced control logic and coordination that is typically enabled by Grid DERMS platforms. In other words, use cases such as Flexible Interconnection can be deployed independently of a DERMS in certain contexts. For example, for residential rooftop systems, which have more limited grid impacts, it may be cost prohibitive to deploy additional hardware and software to facilitate a more complex interconnection agreement. In these cases, localized, autonomous control through Flexible Interconnection may make more sense. However, for more complicated Flexible Interconnection arrangements, (e.g. managing multiple large DER on a single circuit or substation) a centralized Grid DERMS (which we explain below) is critical to ensure that the system can be operated safely and reliably. These types of centralized arrangements typically have multiple control thresholds and "fail-to-safe" logic to ensure that these DER do not inadvertently introduce detrimental grid impacts. In response to the GECs' Comments, we also note that advanced inverter functions are already required under our current Technical Interconnection and Interoperability Requirements (TIIR) guidelines. We will continue to report on progress in obtaining a DERMS in future IDPs, while changes to active or ongoing interconnection projects will continue to be addressed by the TIIR, as directed by the Commission in Docket No. E002/CI-16-521.

To further illustrate the need for DERMS, we explain our current approach to implementing it and more about the technology below.

First, it is important to note that DERMS is not a singular, off-the-shelf software product. Rather, it is an ecosystem of related and integrated software tools, business, planning, and operational processes that enable functional outcomes for specific use cases. Within this DERMS ecosystem, the Company's DERMS strategy includes a roadmap of incremental deployment for two foundational and complementary software systems: Aggregator DERMS and Grid DERMS, with Aggregator DERMS being implemented first and Grid DERMS being implemented to focus on priority use cases. Many of the GECs' Comments specifically related to use cases facilitated by Grid DERMS. Nevertheless, the Company provides additional discussion of Aggregator DERMS to explain the broader context of our DERMS roadmap and the incremental and measured approach to deployment we are pursuing.

Aggregator DERMS typically utilizes a cloud-based "software as a service" model to quickly deploy customer-facing programs and is not typically integrated with other operational technology systems (e.g., ADMS and Supervisory Control and Data Acquisition (SCADA)) that can provide real-time visibility into the state of the grid. Many of the vendors that provide these solutions are legacy demand response management system (DRMS) providers that have modernized their platforms to provide enhanced management of DER types, including demand response, smart thermostats, batteries, and Electric Vehicle (EV) chargers or subset of these DER types. Therefore, 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. This component of our DERMs strategy is a "no regrets" step for modernizing new and existing load flexibility products; however, Aggregator DERMS typically lacks the ability to provide real-time visibility and control.

Alternatively, Grid DERMS software platforms provide real-time and near-real-time visibility and control capabilities and functions and typically is integrated with other key operational technology systems such as SCADA and ADMS. Unlike Aggregator DERMS, Grid DERMS may require additional hardware (e.g. industrial grade gateway devices) to provide enhanced visibility, communication, and control for large-scale DER. Deployment of these capabilities tends to be more costly relative to Aggregator DERMS, technically challenging, and requires significantly more lead time to deploy; however, it offers the significant benefits of enhanced integration and connectivity, which will be necessary as DER penetration increases over time.

The Company is in the early stages of exploring initial, priority use cases for Grid DERMS. This more limited demonstration of specific use cases is a critical interim step to ensure that Grid DERMS capabilities are deployed prudently in a way that provides benefits to customers, the system, and the Company. The Company is not aware of any utilities that have immediately pursued or implemented a "System-Wide Centralized Control" approach of Grid DERMS, as the GECs insinuate, nor is the Company proposing to do so. Rather, the phased, incremental approach we are pursuing focuses on priority use cases that provide the Commission and interested stakeholders with transparency into the timing and costs of our DERMS roadmap.

We request that 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.

## III. CBA FOR DISCRETIONARY PROJECTS

Fresh Energy, GECs, and the City of Minneapolis commented on Order Point 29 of the Commission's July 17, 2023 Order in the Company's most recent electric rate case (Docket No. E002/GR-21-630), which required that the Company discuss the feasibility of conducting CBAs for discretionary distribution system investments. They all agreed that the Company should conduct CBAs for discretionary projects and programs, although the details of their recommendations on this issue varied.

The term "discretionary project" is not one of the financial categories defined for the IDP or a separate budget category for the Company. Table D-1: Financial Categories Cross-Reference, included in *Appendix D: Distribution Financial Information* of our IDP filing and provided as Table 2 below, cross-references the IDP categories to our capital budget categories.

**Table 2**
**Financial Categories Cross-Reference IDP**

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

Most of the discretionary investments fall under the Capacity and Asset Health & Reliability categories in our capital budget, so we focus on these two categories below. These types of investments are distinct in nature and are treated differently when costs and benefits are assessed, as described below.

As the Company explained in the 2023 IDP, the sheer volume of discretionary projects in the five-year budget makes conducting a CBA for each project impractical and costly. It is simply not an efficient use of our available resources to conduct a CBA for all discretionary projects. We are concerned that the funds and resources that would be needed to conduct hundreds of CBAs would impede on other work that is required to serve our customers. Besides the inefficient use of funds and resources, we discuss below several other reasons why conducting CBAs for discretionary projects is unnecessary.

## A. Capacity Investments

Capacity projects include capital investments that are associated with upgrading or increasing distribution system capacity to handle load growth on the system, due to new customers or existing customers increasing their load. Examples of capacity investments include installing new or upgraded substation transformers and distribution feeders. Capacity projects sometimes span multiple years and are necessitated by increased load from either existing or new customers. Many Capacity projects that are initiated due to increasing load also inherently increase hosting capacity for DERs, due to the nature of the investment.

As discussed in more detail in *Attachment D: Risk Scoring Methodology* of our 2023 IDP, we already apply a risk scoring methodology to evaluate and prioritize Capacity projects. This risk analysis is one type of CBA and considers financial benefits, reliability benefits, and costs for a specific project. The analysis also applies other jurisdictional factors, such as discount rates, tax rates, inflation rates, and SAIDI data to the financial benefit and reliability benefit. The benefit-cost ratio, or Risk Score, is calculated based on the benefits (both financial and reliability) and annualized cost for each project. *Attachment E: Risk Scored Projects* of our IDP includes information and risk scores for 108 Capacity projects.

We do not believe additional CBA analysis is needed for distribution system investments that fall under the Capacity project category. Capacity projects are part of the core distribution planning and operations function for every utility. The need for these projects is driven by our responsibility to serve new customers and increased load safely and reliably. We already provide transparent risk analysis and cost information for Capacity projects and do not believe that they should be subject to any additional cost-benefit analysis in the IDP process.

## B. Asset Health & Reliability Investments

Fresh Energy proposed that the Company should be required to provide a CBA for six specific categories of Asset Health & Reliability investments.

These include five types of investments in the **Proactive Asset Health** category:

- *Substation Renewal Programs* ($161 million from 2024-2028). Proactive replacement of substation equipment, including transformers, breakers, switches, regulators, relays, etc.

- Line Renewal Programs:
  - *Network Renewal* ($34 million). Includes new transformers, protectors and vault tops.
  - *Line Equipment Renewal* ($517 million). Includes new porcelain cutouts, arrestors, reclosers, etc.
  - *Pole Related Renewal* ($203 million). Includes pole fire mitigation and multi-feeder pole mitigation.
- *Discrete Projects* ($137 million). Includes discrete rebuild projects targeting aging equipment or infrastructure including substation rebuilds and 4kV conversions.

The sixth category of investments is under the **Reliability** category:

- *Cable Replacement Program* ($207 million). Criteria-based program to replace tap and mainline cable.

Asset Health & Reliability programs and projects are driven by engineering analyses to address aging infrastructure and to improve system resilience. Projects in these two categories are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting service reliability and increasing O&M expenditures needed to repair the equipment. When poor performing assets are identified, projects that will improve asset performance are included in the five-year budget. Investments in these categories include replacing underground cables, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their useful life. These categories also capture replacements that are necessary due to storms and public damage.

We calculate a risk score for discrete Asset Health projects, which is based on five years of historical customer minutes out (CMO) from outages on the component of the system that will be renewed by the project. However, there are several reasons why a fully developed CBA is not appropriate or has limitations for Asset Health & Reliability projects. For these projects, we must strike a balance between mitigating reliability risks, planning for long-term operations, and addressing the aging of our system. In addition, a CBA does not reflect qualitative benefits or intangible factors. Our understanding is that stakeholders often disagree on these intangible benefits and have varying priorities for distribution system investments, such as whether they should target disadvantaged areas or prioritize hosting capacity for small residential installments.

In addition, these are projects that require risk analysis based on age and condition, which does not necessarily show short term cost-effectiveness. For example, we must replace failing poles and overhead lines regardless of whether they are in a densely populated neighborhood or in a rural area that has only five houses. The project's benefits in the rural area will be lower, but it is our responsibility and obligation to serve customers safely and reliably. While we consider the age and condition of assets, we also analyze long-term mitigation. We use inspection programs, which may determine it is more prudent to replace assets, such as poles, in smaller sections, instead of waiting until an overwhelmingly large number of poles need to be replaced at the same time. A CBA would not take into account these types of decision-making factors on timing for limited resources.

Performing a CBA for each of the six programs proposed by Fresh Energy would be impractical and complex. For example, the Substation Renewal Program alone has several different subprograms, and each of the subprograms is focused on replacing different substation components such as transformers, switches, breakers, and regulators.

Additionally, the Cable Replacement Program is not well suited for a CBA. The focus of this program is to respond to outages caused by cable failures and to replace cable that is either damaged beyond repair or has failed more than once in a two-year period. If these reactive failures are lower than anticipated in a given year, the Company plans to make proactive replacements of cables with the remaining funds. However, predicting the amount of reactive cable replacements that will occur each year is difficult, as there is annual variability in the number of cable failures.

While we oppose conducting CBAs for all discretionary projects, and for the six specific categories of projects recommended by Fresh Energy, we are open to discussing these issues with stakeholders, collaborating with them, and having additional conversations on approaches for applying CBAs, or a similar type of evaluation, strategically to program-level investments. However, we continue to believe that conducting CBAs for discretionary projects – even if narrowed significantly – is unnecessary and an inefficient use of our limited resources.

We also note that, in general, the purpose of the IDP is to provide planning information on our distribution system. Although the Commission reviews the Company's distribution system plans, the Company has flexibility to respond to dynamic system changes and to conduct necessary on-going system improvements.[38] Accordingly, the Company should be able to use our knowledge, expertise, and engineering judgment in selecting investments for the distribution system. In addition,

[38] See Docket No. E002/CI-18-251 Planning Objectives, Minnesota Integrated Distribution Planning Requirements for Xcel Energy, as modified by the December 8, 2022 ORDER in Docket No. E002/M-21-694.

as stated throughout these Reply Comments, the IDP does not involve prudency determination of any proposed investments. The Company must show in a separate cost recovery process that all distribution system investments are justified and reasonable, and it is in those separate proceedings that the Company bears the risk that cost recovery may be denied by the Commission.

To summarize, we request the Commission accept our proposal to engage in additional stakeholder discussions on approaches to apply CBAs, or similar type of evaluation, strategically to program-level investments for discretionary projects. It would be impractical, unnecessary, and inefficient use of resources to conduct CBAs for all discretionary projects, or even the six categories of projects specified by Fresh Energy, and we request the Commission decline any other recommendations by parties regarding CBAs for discretionary projects.

## IV. NON-WIRES ALTERNATIVES (NWA)

The Comments from the Department, the City of Minneapolis, and Fresh Energy all contained questions and recommendations about our process for evaluating NWAs, the three feasible projects we identified in the 2023 IDP, the kinds of projects NWAs are best suited for, the time horizon for evaluating NWAs, accounting for the potential impact of incremental energy efficiency and demand response on capacity risks, and the RFP process. We address each of these topics below within the context of our NWA evaluation process. Additionally, the Department took the position that the Company did not comply with Order Points pertaining to NWAs. At the end of this section, we have provided a table illustrating that we have complied with all NWA related Order Points, and where in the IDP this information can be found.

Since the establishment of IDP Requirements 3.E.1, 3.E.2, and 3.A.5.d in the Commission's August 30, 2018, Order in Docket No. E002/CI-18-251, the process for evaluating NWAs has substantially evolved. Year-over-year the Company has continued to refine the methodology and engage stakeholders (gaining significant feedback). We have also crafted the initial steps needed to conduct an NWA pilot.

During the first NWA compliance filing submitted in our 2019 IDP,[39] the NWA screening process began with a simple comparison of the capital costs of a traditional capacity project to the full capital costs of an NWA. This has now evolved into a more detailed screening process involving stacked values, Avoided Revenue Requirements (ARR) split, and utilization of LoadSEER outputs. We expect

[39] *In the Matter of Xcel Energy's Integrated Distribution Plan (IDP) and Advanced Grid Intelligence and Security Certification Request,* Docket No. E002/M-19-666, INTEGRATED DISTRIBUTION PLAN, SECTION VI (November 1, 2019).

continued stakeholder engagement and feedback in the future, and we will continue to make improvements where appropriate.

Over the years, certain foundational concepts have stayed true. Three of these foundational concepts are: 1) the definition of an NWA, 2) capacity projects being the best fit for an NWA, and 3) the filter to only look at projects in years three to five of the five-year budget.

An NWA consists of projects in which a utility uses DER to alleviate a constraint on the grid, instead of relying on conventional transmission and distribution assets. In the context of our IDP, DERs are supply and demand-side resources that are installed on either the customer or utility side of the electric meter. For example, an NWA could be an optimized combination of battery storage, solar, and demand response as an alternative solution to addressing a traditional mitigation, which could include installing new or upgrading existing feeders or substation transformers to mitigate multiple overload risks on several feeders.

As noted above, one of the foundational concepts used in the NWA screening process is that capacity projects are the most appropriate fit for an NWA. This is because capacity projects:

- are driven by historical and forecasted N-0 and N-1 overload risks;
- are not subject to external requirements for the project timeline and scope (unlike mandated projects, for example);
- have a lead time that corresponds with the lead time needed for an NWA project (asset health and reliability projects generally require in-servicing sooner than three years;.
- have a wide breadth of benefits to the system (for example, capacity often benefits reliability but reliability does not necessarily benefit capacity); and
- are located where we are typically expanding the distribution system to accommodate new load. This is where an NWA could provide a key opportunity to defer that system expansion. Asset health and reliability projects usually involve like-for-like renewal of aging assets (while updating to current standards), and an NWA cannot defer the need for replacement of the aging asset. The asset would only continue to fail more and more frequently until irreparable failure occurs, potentially causing customer outages until that failed asset is replaced.

The Company described in further detail why capacity projects are most appropriate for an NWA in *Appendix F: Non-Wires Alternatives Analysis*, Section III.A, B, and C. Capacity projects are the best fit for an NWA, and it is important to note that they also benefit other parts of the system. We would like to clarify that while adding capacity to an area can benefit reliability, a project to benefit reliability will not necessarily benefit capacity. This is because of how capacity is added to the system. From a feeder perspective, one method for adding capacity could be to upgrade mainline equipment, as it supports the entire feeder, not just a single tap.[40] If an undersized conductor on a tap is causing reliability issues for a neighborhood, installing an NWA solution involving storage, solar, etc., on the tap does not necessarily add capacity, it simply fixes one issue with the part of the grid that serves the small neighborhood. If the NWA were to address a capacity issue, depending on the scope, reliability for all customers on the feeder, not just a small neighborhood, has the potential to increase. This is why capacity projects are the best fit for NWA projects.

Another foundational concept used in the NWA screening is the filter for only conducting NWA analysis on projects in years three to five in the five-year budget. This enables the Company to ensure that time for market solicitation, engineering, and lead times for acquiring equipment is accounted for. This is in line with our approach in PSCo. A five-year deferral period ensures that the NWA is sized accurately, as forecasts have the potential to decrease in accuracy the further the forecast projects into the future. While an NWA is assumed to provide a five-year deferral of the traditional project, this does not mean that the project couldn't provide value beyond five years; extended or additional PPAs could be established if an NWA can still meet the capacity need after five years, or the NWA technology could be used for other operational purposes if it is not able to meet the capacity need. This information is also discussed in *Appendix F*.

The three foundational concepts discussed above are part of the Company's initial NWA screening process. The primary concern of this initial screening is to find an NWA that could reasonably mitigate a capacity issue in lieu of a traditional project. These traditional projects address real risks on the system that exist currently and are forecasted to continue; thus, the primary considerations of an NWA must be demand, capacity, and associated risks. Because our customers are all equally deserving of safe, reliable power, these primary considerations supersede any customer demographics, and equity is not an appropriate value to include in the initial screen. In fact, adding additional criteria to our initial screening process could make it even more challenging to find a cost-beneficial NWA, as it would limit our options. However, the Company will consider environmental justice (EJ) areas as we move past the initial stages.

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[40] This is discussed in *Appendix F: Non-Wires Alternatives Analysis*, of our 2023 IDP.

One thing that the NWA analysis cannot account for is for the potential impact of incremental energy efficiency and demand response on capacity risks. The only data we have access to is existing customer enrollment and participation in demand response and energy efficiency programs. As we stated in our response to Department IR No. 49,[41] such an undertaking would require an extremely large data set with very granular customer-specific data that could be used to identify potential impacts to the outcome of an NWA project. The type of information required, such as customer owned behind-the-meter equipment and incremental energy efficiency potential for specific customers – as well as the impact it would have to the 24-hour customer demand shape on peak day, is not available to the Company. This type of information changes frequently with customer choices the Company is not privy to, such as the exact make and model of appliances. This list of details that could be required is not all-inclusive, but representative of types of data that would be needed for this to be possible. Additionally, the Company has not seen an NWA methodology that showcases specific data and formulas for conducting this type of in-depth analysis. Even if we could find the data granularity and methodology needed for this type of analysis, it would be difficult for the Company to implement this operationally, as our demand response programs cannot easily geo-target specific areas without a DERMS implementation.

For projects that passed the initial screening discussed above, any RFPs issued for NWAs would be technology agnostic, as they were in PSCo, with the goal of finding the best, least cost solution for providing the required load reduction requirement to mitigate risk and mitigate a particular capacity issue. As discussed in *Appendix F,* the ARR split concept reflected in the NWA analysis is most similar to that of a PPA structure, thus, if a developer was selected for a project, the Company would most likely pursue an agreement with an energy services agreement, like the Non-Wires Alternatives Services Agreement we developed in PSCo. More information about this topic can be found in our answers to Department IR Nos. 45 and 48.[42]

Regarding our compliance with the Commission's Orders, we would like to specifically address the Department's comment that the Company did not comply with Order Point 3.E.1, which directs that:

> *Xcel [Energy] shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*

[41] *See* Docket No. E002/M-23-452, Department's March 1, 2024 Comments, Attachment B.
[42] *See* Docket No. E002/M-23-452, Department's March 1, 2024 Comments, Attachment B.

As indicated in the table below, we provided a detailed discussion and analysis on how the three NWAs identified as feasible in our IDP filing compare in terms of viability, price, and long-term value. For the projects that were not feasible, we explained why and how they were determined to be so. It would be inefficient and a waste of resources to provide further analysis on projects that are deemed infeasible. Additionally, the Company has been responding to this requirement for several years, using the same method for each IDP and annual baseline filing. In prior years, we have been found to be in compliance, and the Commission had accepted these IDPs.

The Commission has directed the Company to report on several Order Points related to NWAs in the IDP. We complied with all of these in our 2023 IDP filing, and have provided the table below, indicating where we comply with IDP Order Points 3.E.1, 3.E.2, and 3.A.5.d., and Integrated Resource Plan (IRP) Order Point 9.D.[43] We also include a brief description of how the Company addressed them in the 2023 IDP in Table 3 below.

**Table 3**
**NWA Order Point Compliance**

| Requirement | Description |
|---|---|
| 3.E.1: Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value. | Table F-3 illustrates the full list of 2023 NWA candidate projects that advanced to the initial screening process. *Appendix F,* Section VIII. Project Feasibility, describes what comprises an infeasible project in-depth. The results in Table F-3 have a column titled "Feasibility" which indicates the feasibility result of that particular element of a project. Ensuring that a project can meet the load reduction requirement is a key factor in the feasibility of a specific risk. |
| 3.E.2, a, b, c, & d: Xcel shall provide information on the following:<br>a) Project types that would lend themselves to non-traditional solutions (i.e., load relief or reliability)<br>b) A timeline that is needed to consider alternatives to any project types that would lend themselves to non- | a) The Company met this IDP requirement as reflected in *Appendix F,* Section III. Project Type. We describe mandated projects, asset health and reliability projects, and capacity projects. In these sections, there is a discussion about why capacity project types are the best fit for non-traditional solutions. |

[43] See Docket No. E002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS (April 15, 2022).

| | |
|---|---|
| traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)<br>c) Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed<br>d) A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made. | b) We met this IDP requirement in *Appendix F*, Section IV. Timeline. We discuss the need for a minimum of a three-year timeline and highlights some of the challenges.<br>c) *Appendix F*, Section V. Project Cost addresses this Order Point. As described, we only considered traditional projects greater than $2 million in cost per IDP requirement 3.E.1.<br>d) *Appendix F*, Section II NWA Analysis in the Planning Process up until Section VII 2023 NWA Enhancements addresses point d. The screening process is broken down into multiple step-by-step flow charts that illustrate the process. |
| 3.A.5.D: Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including:<br>d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources | *Appendix F*, Section VII. 2023 NWA Enhancements addresses this Order Point. We describe enhancements to the analysis as well as the impact that they provide to the results. Additionally, we discuss three potential candidates for a future NWA pilot in Section XI. Future NWA Pilot. A project could go for market solicitation in the future.<br><br>As discussed in *Appendix F*; Section VI. Risk Type, Size, Quantity; Step 3: Identify ARR Split; the previous NWA methodology included a consideration of the full lifetime of an NWA. In the current methodology, a five-year deferral period is used. |
| 9.D: Xcel shall stake steps to better align distribution and resource planning, including:<br>d. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs. | See description of Order Point 3.A.5.D. |

We request that the Commission find that the Company is not deficient in our reporting on NWAs and decline the Department's recommendations regarding NWAs, including their recommendation that we be required to consider NWAs for all non-asset-based distribution system projects. We also request that the Commission decline the City of Minneapolis' request for a comment opportunity for any RFPs.

## V. PROACTIVE GRID UPGRADES FOR HOSTING CAPACITY AND COST ALLOCATION

The Company received many Comments that spoke to the challenges of selecting proactive grid upgrade projects. Instead of answering all the related Comments made by various parties, we would like to continue the conversation through stakeholder workshops, as Fresh Energy suggested. The Company appreciates Fresh Energy's engagement with this docket and agrees that more record development is needed to help us determine a framework for developing and selecting actual projects. Given the extensive stakeholder engagement the Company has conducted in the IDP – we held six stakeholder workshops in conjunction with the 2023 IDP planning process – and continues to conduct in other dockets, we would like to propose that it be limited to a two-workshop series, with each workshop having a distinct purpose and goal. At the first workshop, we would have stakeholders present their ideas, which we would then take for consideration in developing a framework. At the second workshop, the Company would present our thoughts and recommendations for a framework based on stakeholder input from the first meeting.

We would like to note that on March 14, 2024 at the Commission Agenda Meeting on Docket No. E999/CI-16-521, the Commission made and oral decision to not establish a carve-out for residential solar. This will be an integral part of the overall conversation and our recommendations. The two workshops proposed above would cover the relationship between proactive upgrades for hosting capacity and the status of a carve-out for residential solar.

Parties may also find that many of their questions regarding proactive upgrades for hosting capacity can be answered by *Appendix E, Appendix I: Distribution System Upgrades,* and our response to Department IR No. 32.[44] *Appendix E* addresses many questions the Department had, in particular about accommodating additional DER on our system, while *Appendix I* contains a high-level assessment of forecasted capacity constraints that could be addressed by proactive system upgrades.

We would like to specifically address the Department's request for us to discuss whether we have considered energy storage to alleviate current or future DER capacity constrained feeders. We addressed this topic in Section II.A. of *Appendix E* in our 2023 IDP. This Appendix also addresses many of the other questions the Department posed relating to accommodating additional DER on our system. Our

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[44] *See* Docket No. E002/M-23-452, Department's March 1, 2024 Comments, Attachment B.

response to Department IR No. 32 explains more about what kinds of investments potential system upgrades could be.

The Company requests that the Commission defer any decisions about additional reporting requirements related to proactive grid upgrades for hosting capacity until after stakeholder engagement sessions have been held and the results are discussed.

## VI. BUDGETING PROCESS

We received many Comments and recommendations about issues of clarity with the IDP budget categories, incorporating non-traditional priorities into our prioritization objectives, and the potential for adding additional metrics to evaluate cost-effectiveness of capacity projects. We address these topics below.

### A. Clarity and IDP Budget Categories

First, we would like to respond to the recommendations the Department made surrounding how we report our budget and confusion about what kinds of projects fall into which budget categories. For instance, the Department asked about whether our Age-Related Replacements and Asset Renewal budget (an IDP category that is mostly analogous to our company category of Asset Health and Reliability) also includes capacity expansion benefits. In some cases, projects that are included in Age-Related Replacements and Asset Renewal also provide a capacity benefit. However, projects that are intended to provide a capacity increase belong and are reported in the Capacity category (a Company budget category that is represented in many IDP categories). For example, there may be some cases where we see a capacity benefit from Age-Related Replacements and Asset Renewal projects, but most of the benefits from the project will be in terms of reliability, which is why we categorize them internally as an Asset Health and Reliability project, and historically as an Age-Related Replacements and Asset Renewal project for the IDP.

Fresh Energy requested an explanation about why the Company's budget for System Expansion or Upgrades for Capacity (an IDP category that we have placed certain Capacity projects into) increased. The increase in the Company's System Expansion or Upgrades for Capacity expenditures in 2024-2028 compared to 2019-2023 is largely due to the increases in proactive grid upgrades and grid reinforcement expenditures – which make up about $322 million (or 44 percent) of the amounts reported in this IDP – and not due to any changes in the number of risks. To clarify, on page 73 of *Appendix A1: System Planning,* we stated in our risk analysis results that there are 67 N-0 normal overloads on feeder circuits where "N-0 normal overload" specifically refers to feeders loaded over 100 percent. This does not mean that there are only 67 feeders that exceed the 50/75 percent threshold; in fact, the quantity of feeders exceeding 50/75 percent is significantly greater. Additionally, the change in threshold does not impact the quantity of risks – it only impacts the quantity and magnitude of mitigations to address those risks. For example, in the 2021 IDP[45], we listed 566 N-1 risks, but 566 was not the count of feeders in need of a mitigation. The number of feeders that needed a mitigation was a subset of the 566 risks, exclusively comprising those with an N-1 risk exceeding 3 MVA of load at risk. Therefore, 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.

As stated in *Appendix D* and discussed in Section III. of these Reply Comments, the IDP categories overlap with, but do not perfectly match, the Company's budget categories that we present in other filings, such as rate cases and riders. Table D-1: Financial Categories Cross-Reference, provided as Table 2 in this Reply, demonstrates that there is not a one-to-one relationship between the Company's budget categories and those required in the IDP. We appreciate the Department's alignment with our recommendation to remove the requirement that financial information be reported in IDP-specific categories. We believe many issues of clarity will be resolved once we begin using our internal budget categories to report our distribution budget, such as which projects roll into which categories. However, in our current reporting, we do list most actual projects in Attachment H: Capital Projects List. Where there are no distinct projects listed, we typically have no active, internally approved projects. Instead, those higher-level buckets represent money that has been budgeted for potential projects.

## B. Non-Traditional Priorities Create Clarity Issues

The GECs expressed interest in how the Company could incorporate priorities such as hosting capacity and equity into these objectives. While equity is important to the Company and is discussed in more detail in Section I of these Reply Comments, near-term investments in our distribution system are focused on achieving four primary objectives: (1) preparing for the future; (2) enabling the clean energy transition; (3) maintaining and enhancing reliability and resilience; and (4) modernizing the grid. Incorporating non-traditional goals into our prioritization process would be resource intensive and it would likely be more effective to treat non-traditional goals as separate categories with their own prioritization criteria based on specific criteria for feasibility, costs, and benefits.

## C. Additional Metrics to Evaluate Cost Effectiveness of Capacity Projects

[45] See Docket No. E002/M-21-694, 2021 Integrated Distribution Plan (November 1, 2021).

In response to the Department's request for feedback from the Company and other parties as to the feasibility of providing additional metrics to evaluate the cost-effectiveness of capacity projects and which metrics would potentially be the most useful for evaluation, the Company thinks that additional metrics are not needed. Capacity projects must be done to maintain the reliability of our system, and the project risk score is the measure we should prioritize. We discuss our risk scoring in Section III.A. of these Reply Comments and in Attachment D: Risk Scoring Methodology of our 2023 IDP.

### D. Budget Recommendations

We request that the Commission decline the recommendation the Department made for the Company to separate the total program and project budgets into discrete programs and budget categories. We also request that the Commission decline the GECs' requests that the Company be directed to incorporate equity and hosting capacity into our budget prioritization process and for us 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.

We request that the Commission approve our recommendation to remove the requirement that financial information be reported in IDP-specific categories, as supported by the Department.

## VII. RELIABILITY AND RESILIENCE

The Department recommends that the Company be required to include a report of reliability performance for circuits equipped with FLISR in the IDP. As we stated in our responses to the IRs from the Department,[46] the Company defines resilience for the distribution system as focusing on the system's ability to withstand, endure, and recover from significant events that can create widespread outages and result in long-duration restoration times. As the Company already reports many metrics related to reliability in our Annual Service Quality and Performance Based Ratemaking (PBR) filings,[47] creating additional goals and metrics for FLISR and reporting these in the

[46] *See* Docket No. E002/M-23-452, Department's March 1, 2024 Comments, Attachment B.
[47] Our annual Service Quality filing is forthcoming in Docket No. E002/M-24-77, and PBR is reported annually in Docket No. E002/CI-17-401.

IDP would be overly duplicative, and we would direct any discussion of changes or additions to our current reliability reporting to those dockets.

SAIDI and SAIFI are industry accepted metrics that the Company reports on annually in our Service Quality dockets and are designed to measure electric power utility reliability. Therefore, over time, SAIDI and SAIFI should provide an indication of the effect FLISR is having on reliability. In addition to SAIDI and SAIFI, we report annual reliability performance results for CEMI, CELI, CAIDI, MAIFI, and normalized/non-normalized data for feeders with grid modernization investments.[48] The Company uses the Commission approved IEEE 1366 threshold calculation process to report reliability metrics in our Annual Service Quality filings.

In the PBR docket, the Company reports on a myriad of metrics covering affordability, reliability,[49] customer service quality, environmental performance, and cost-effective alignment of generation and load.

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. Additionally, we note that we will respond to Order Points 25 and 27(a) of the Commission's July 17, 2023, Order in Docket No. E002/GR-21-630 in our Service Quality filing due on April 1, 2024.

Additionally, as we said in our response to the Department IR No. 14,[50] FLISR provides reliability benefits to feeder level outages (not outages at all levels), and one of the Company's criteria is to target parts of the distribution grid that have had a higher number of feeder level outages. The Company understands the Department's recommendation to be asking for a comparison of reliability at all levels before the Company started the FLISR project and after the Company has completed at least one of the phases of implementing the FLISR technology on an individual feeder. The Company believes there is limited value for such a comparison, as reliability is a combination of many factors and variables – comparing reliability at all levels and trying to attribute reliability to a single factor like FLISR is unlikely to draw any meaningful conclusions, especially given the Company is currently in the early stages of the FLISR deployment.

[48] As found in Part II of our forthcoming Annual Service Quality Reliability report that will be filed on April 1, 2024 in Docket No E002-M-24-27.
[49] This includes SAIDI, SAIFI, CAIDI, CELID, CEMI, ASAI, MAIFI, and power quality.
[50] *See* Docket No. E002/M-23-452, Department's March 1, 2024 Comments, Attachment B.

Lastly, the Department also recommends that the Company further develop and clarify its resiliency metrics for the RMP to includes measures of system performance during major outage events. The Company believes the best place to discuss and potentially adjust any RMP-related metrics would be in the RMP proposal docket – Docket No. E002/M-21-694.

We request that the Commission decline the Department's recommendation to have reliability metrics concerning FLISR reported in our IDP and confirm that reliability reporting should be kept in the respective dockets.

## VIII. FORECASTING

### A. Load Forecasting and LoadSEER

The Department recommended that, in the next IDP, the Company provide the following:

*a) a complete list of the data sets used in making the LoadSEER forecast, including:*
*b) a brief description of each data set and*
*c) 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);*
*d) a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:*
  - *the nature of the adjustment,*
  - *the reason for the adjustment, and*
  - *the magnitude of the adjustment;*

*e) a discussion of each essential assumption made in preparing the LoadSEER forecast including:*
  - *the need for the assumption,*
  - *the nature of the assumption, and*
  - *the sensitivity of forecast results to variations in the essential assumptions;*
  - *an equation showing the LoadSEER forecast model, for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …*
  - *information documenting the LoadSEER forecast's confidence levels, statistical accuracy of the individual variables and overall model, and so forth; and*
  - *the outputs from the LoadSEER forecast.*

The Company sees this request as extremely problematic for two reasons. The first reason is that much of this information, including the formulae for the forecast model, is the intellectual property of LoadSEER. The Company is not the developer of LoadSEER; we are simply users of the tool.

Second, we believe much of the Department's request can already be found in our 2023 IDP. All assumptions used in LoadSEER and the load forecasting process as a whole were included in *Appendix A1*, where the Company describes every step of the load forecasting process in-detail to the granularity that we have available to us. Requesting additional levels of detail is either unnecessarily burdensome to the Company, or impossible, as some of the information is not available.

Fresh Energy had several comments requesting clarification on aspects of forecast accuracy, including if we could perform a sensitivity analysis on relevant capital expenditure categories, requesting that the Commission direct us to develop a commercial electrification forecast, and the use of a 576-hour time series in LoadSEER. We respond to these below.

The Company agrees that it is important to have robust and methodologically sound forecasting. One way we are looking to improve our forecasting abilities is to complete capacity investment analysis using the IDP scenarios. We agree that our forecast would be more well-rounded if we followed up the forecast scenario analysis with a capital expense analysis and envision that a high-level analysis could be realistic in the future. However, conducting an in-depth process that involves creating individual mitigations for all N-0 and N-1 risks (for both feeders and substation transformers) for each scenario would be a monumental task in terms of time and expense. We would likely need to use contract labor to undertake this endeavor and estimate that it could cost around $1.5 million dollars. The Department requested that we discuss the feasibility of conducting additional analysis of distribution system upgrade costs for additional types of DERs under various scenarios. We discuss a forecast of upgrade costs for solar in *Appendix I*.

Additionally, the Company is considering methods for advancing our DER forecasts. The IDP low, medium, and high scenarios are our current iteration of forecasting with DER and electrification considerations in LoadSEER, but future IDP scenarios will build on our internal learnings and our collaboration with stakeholders during workshops. The eventual addition of a commercial electrification forecast is one way we are looking to advance our DER forecasts and is something stakeholders have expressed interest in. However, as stated in Section II.C.3. of *Appendix A1* of our IDP, beneficial electrification (BE) forecasts are currently only available for residential customers in Minnesota. Commercial and industrial BE forecasts are still under development, and they will be incorporated into our IDP when they are available.

Since we are planning to incorporate these forecasts into our IDP, an order is not necessary.

One key advancement that the Company has already made in load forecasting has been moving to an 8760-analysis framework. LoadSEER has been a key tool for enabling this level of detail of analysis. 8760 analyses have myriad benefits over a 24-hour, 288, or 576 type analysis. Where able, we plan to advance our planning process methodologies to utilize all the benefits that an 8760 can provide. A more in-depth discussion can be found in Section IX: Planned Net Loading of these Reply Comments.

Although forecasts are inherently uncertain and never 100 percent accurate, the Company tries to mitigate the inherent risks of forecasting by developing plans that are robust over a wide range of potential future outcomes. We do this by accounting for trends in factors such as economics, customer and industry trends, and the weather in our various scenarios. Additionally, we are currently considering methods for how to measure forecast accuracy, and we are constantly looking for ways to improve our forecasting abilities. With that being said, the more time we spend comparing forecasts to actuals and striving for forecasting to be perfect is time we are not spending on maintaining and modernizing our distribution system. It is important to have robust and methodologically sound forecasting, so we do not over- or under-build our system, and the forecast we submitted as part of our 2023 IDP is reasonable and based on sound statistical models and the best assumptions available at the time they were created.

We request that the Commission decline the Department's recommendations regarding LoadSEER and Fresh Energy's recommendation that the Company be directed to develop a commercial electrification forecast, as well as a more robust residential electrification forecast for the next IDP.

## B. Impacts of the Inflation Reduction Act (IRA)

The Department made two requests for more information about how our distribution system planning will evolve with the incorporation of impacts from the IRA and on the impacts of related planning assumptions on commercial and industrial customers, in particular. The City of Minneapolis recommended that we double our adoption rate assumption when factoring in IRA funding.

In response to the Department's Comments, the Company has a robust forecasting process that accounts for IRA impacts, which is based on trends that we monitor and updated accordingly. As we stated in *Appendix A1: System Planning* of our 2023 IDP, the IRA and (and other recent Federal and State legislation) have many opportunities for acquiring funding and tax incentives, which will impact how the Company and the energy industry at large will proceed with planning. The IRA in particular provides opportunities for utilities and our customers to capitalize on incentives for the development of renewable energy resources. We are continuously exploring these options and evaluating how they may impact our plans for the system. Specifically, in relation to our distribution system, we have incorporated incentives offered by the IRA into our forecasted adoption rates for EVs and solar.

In response to the City of Minneapolis, our forecast is based on trends that we monitor and update accordingly, as well as provisions in the IRA itself. For example, based on the IRA tax credit rules for EVs, many vehicles on the market do not qualify for the credit, and the eligibility requirements will continue to become more stringent each year. Economics is not the only thing that factors into an individual's decision to purchase an EV. The lack of charging infrastructure and long charging times are two prominent considerations for consumers looking to purchase a vehicle. Another trend we considered are recent announcements made by many auto manufacturers indicating that they are significantly scaling back their EV investments and shifting their focus to Plug-in Hybrid Electric Vehicles (PHEVs), due to a change in consumer demand. PHEVs typically consume significantly less electricity due to their dual fuel capability; therefore, the estimated consumption anticipated from EVs has the potential to change significantly due to changing appetite for plug-in hybrids, as well as improvements in vehicle fuel efficiency and changes in consumer demand for battery EVs. Because of these factors, it may be more appropriate to anticipate how the estimated consumption of EVs will be impacted by various factors rather than to base it on today's technology or historical vehicle sales trends.

While we agree that our system needs to be built and upgraded appropriately to accommodate likely expansions in EV and solar stemming from the IRA, based on the trends and factors we discussed above, we do not agree that doubling our forecast is appropriate, as doing so would not be based on any methodological approach to forecasting. If the Company were to arbitrarily adopt higher estimates for increases to the number of EVs, we would risk overbuilding and incurring needless costs and rate increases.

We request that the Commission decline the City of Minneapolis' request that the Company double our adoption rate assumptions when factoring in IRA funding.

## C. Load Flexibility

The GECs made recommendations for the Company to address impacts from time-of-use (TOU) rates on our IDP forecast and to continue refining the incorporation of demand response and load flexibility programs into our forecast. Our proposed TOU rates docket is pending before the Commission and has not yet been decided, making it premature to include TOU rates as part of this IDP. Additionally, as noted in the IDP, the Company will continue to monitor demand response and load flexibility opportunities and will forecast them as additional data is available.

We request that the Commission decline the GECs' recommendations for the Company to 1) to address any impacts from changes in rate design, in particular the use of 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.

# IX. PLANNED NET LOADING

The Comments submitted by the Department concluded that the Company's Planned Net Loading (PNL) methodology is reasonable. In addition, the Department recommended that the Company should not implement the 15 percent $D_{PV}$ in the next planning cycle for N-0 risk analysis. The Company agrees with this recommendation. In addition, Fresh Energy's Comments included several detailed questions regarding the PNL methodology and the 15 percent dependability factor. Also, GECs recommended that the Company continue to refine the PNL methodology, and specifically consider modifications to the dependability factor and explain in the next IDP any decisions made regarding it. We address Fresh Energy's and GECs' comments below.

It appears that there is some confusion regarding the concepts of net and native loading. These concepts are key to understanding the PNL methodology, and we discuss them in more detail below as we address Fresh Energy's detailed questions and GECs' suggestion to increase the dependability factor and to consider seasonal/differentiated dependability factors.

- *Native Loading* (unmasked, gross) is the actual demand including 0 percent dependability of DER impacts. This assumes we can't depend on DER to lower peak due to non-dispatchable generation source. This is a calculated value.

- *Net Loading* (masked) is the actual demand including 100 percent dependability of DER impacts. This is the load we see via SCADA at the substation. This considers all hours of the day, including when DER is not generating.
- *PNL* is calculated demand including partial DER impact. This assumes that we can depend on a percentage of DER impacts. The initial methodology only considers the impacts of solar PV. Future additions may include other DER types (Wind, Hydro, etc.).

It is important to note that net and native loading are the bounds of system loading that PNL must be within. This is because net and native load represent either 100 percent or 0 percent dependability of DER impacts, respectively. If the methodology produces a peak PNL that is less than the peak net load, then that PNL is effectively indicating that over 100 percent of DER is dependable. Similarly, if the methodology produces a PNL that is greater than the peak native load, then that PNL is effectively indicating that less than 0 percent of DER is dependable. Neither of these outcomes would make sense; therefore, the PNL, if implemented, must have a methodology that falls between the net and native loading bounds.

Fresh Energy asked the Company to explain why we are proposing to apply a 15 percent dependability factor to the PV generation impact and not the total nameplate capacity of PV generation. They also asked the Company to explain if using 576-hour time series in LoadSEER has been considered, and if doing so would facilitate the incorporation of LoadSEER results into the Company's capital investment plans or sensitivities.

We created the methodology around dependability of DER impacts on the distribution system loading, not around the dependability of the nameplate rating of DER. This is because, in an 8760 analysis, not all hours in the analysis result in the same level of solar generation; for example, some days in the simulated 8760 load shape might be cloudy, whereas other days might be sunny. By contrast, a 576 analysis, which has been used by some other utilities, centers around idealized 24-hour load shapes for each month. While a 576 analysis is a more simplified approach that focuses on studying possible system loading outcomes on peak day, it fails to capture the variety of weather, loading, and DER generation conditions that may arise throughout the course of a typical year. An 8760 analysis is a more granular approach that captures this variety while still providing insight into peak day conditions, is generally aligned with industry trends, and aligns with our forecasting processes in LoadSEER.

Fresh Energy also asked the Company to explain why the PNL methodology uses values for native and net peak load from different hours on different days, and why it uses a value for net peak load during an hour where solar production is zero.

Net load and native load are separate 8760 data sets for each feeder. In both cases, the DER impact, or lack of DER impact, persists throughout the 8760 data set as appropriate. In the case of solar PV, this means that the differences between the native load 8760 data set and the net load 8760 data set are primarily seen during daytime hours. When evaluating the net load 8760 data, the hour of the year with the greatest demand is the net load annual peak. Similarly, when evaluating the native load 8760 data, the hour of the year with the greatest demand is the native load annual peak. The annual peaks for each are then derived from the data regardless of how much the DER might or might not be generating at the time of the peak. To evaluate net loading only when DER is generating a specific amount or to consider only specific times of day would not be an accurate reflection or true to the basic concept of a net load annual peak.

As a result of this, the net and native annual peaks do not necessarily occur at the same exact time in each 8760 data set. For example, if a feeder experiences a native load annual peak during daytime hours, the load-reducing impact of solar PV generation may be so significant that the net load peak that same day occurs outside of daytime hours, after the solar PV is no longer generating. In this example, the solar PV does reduce the effective system loading to create a net load value that is less than the native load at the time of the native load annual peak. However, the net load annual peak that occurs outside of daytime hours represents the maximum system loading that occurs in the net load 8760 data set and is the peak demand for which the distribution system would need to be planned under net load conditions. Since customer demand and solar generation respond uniquely to different temporal and weather variables, the load-reducing impact of DER will vary each day; this means that not only will the net load annual peak and native load annual peak not necessarily occur at the exact same time, they might not even occur on the same day. A native load annual peak and a net load annual peak that occur at different times and on different days is an expected and normal possibility in an 8760 analysis and accurately reflects what has been observed historically on our distribution system.

In addition, Fresh Energy requested that the Company explain why the 15 percent dependability factor was derived from average winter PV output instead of average summer output, when the majority of the Company's feeders peak in the summer months. GECs also recommended that the Company continue to develop the PNL methodology and in the next IDP consider increasing the dependability factor and consider implementing seasonal or otherwise differentiated dependability factors.

The PNL concept effectively takes the net and native load concepts described above and finds an appropriate middle ground for planning the system by using the dependability factor. This is an important first step in the PNL process because it is important that the planning methodology considers realistic worst-case scenarios.[51] As described in *Appendix A1*, the dependability factor of 15 percent was derived using average winter solar PV output. Winter has lower generation on average due to limited sunlight. Although many feeders in our service territory currently peak in the summer, as electrification increases over the next 30 years, many feeders will likely begin to experience peak demands in the winter that are similar or greater than peaks in the summer. It is important that we plan for peaks that could occur throughout all times of the year, both summer and winter, and the PNL methodology has been developed in a way that is flexible and able to be applied in either case. Since feeders may change from summer to winter peaking throughout the course of the forecast, applying seasonally differentiated dependability factors would require unique values to be determined and applied for each feeder and for each year of the forecast. This would require a large effort by the Company and a significant amount of resources. With approximately 1,500 feeders and banks in our Minnesota service territory and 30 years of forecasted peaks, this would require 45,000 unique and individual dependability factors to be determined and applied.

We believe the Company's proposed PNL methodology is reasonable, and the Department agrees with this conclusion. We request that the Commission find that the Company's PNL methodology is reasonable and accept the recommendation that the Company should not implement the 15 percent $D_{PV}$ in the next planning cycle for N-0 risk analysis. We disagree with GECs' suggestion that the 15 percent dependability factor is overly conservative. We do not believe further consideration regarding increasing the dependability factor or using seasonal/differentiated dependability factors is needed, and request the Commission decline this request made by GECs.

## X. IDP AND IRP ALIGNMENT

The Department requested feedback on how to schedule the IDP to better integrate its inputs and outputs with other Commission processes, and the GECs requested that we supplement our discussion with further information or insights regarding coordination between the IDP and the IRP. In response to these requests, the Company would like to reiterate the timing challenges associated with attempting to align the IDP and the IRP, which have very different time horizons and planning

[51] Please refer to *Appendix A1: System Planning*, page 77 for further discussion on the downstream impacts of the PNL on observed overload risks.

cycle durations and cadences. The IRP indicates size, type, and timing of resource needs over a 15-year time horizon, while the IDP shows a five-year budget of discrete potential projects and investments. The five-year budget shown in the IDP is built every year on the forecast from the previous autumn – in other words, the IDP uses data from a year prior to its submission. Accordingly, we have already started our next distribution planning cycle using Fall 2023 data. This is significantly different in the IRP, where the modeling happens only one to six months in advance of the filing date every few years, with more recent data – generally forecast vintages from approximately three to six months before the filing date. To further complicate the situation, the next IRP can be due on any day of the year, depending on when the Commission approves the current one. However, even if the IDP and the IRP were due on the same day, we would not be able to fully align the forecast vintages because of the inherent differences in the purposes of the IDP and IRP and how they are conducted. However, the Company took measures to align forecast vintages between the IDP and the IRP where possible, as discussed and identified in Table E-3: Forecast Vintage Comparison of *Appendix E* in our IRP filed on February 1, 2024, in Docket No. E002/RP-24-67 (IRP).

Regarding the GECs request for explanation about the difference in the IDP and IRP forecast, particularly that the IDP forecast is approximately 14 GW in 2040 while the IRP is 12.5 GW, the primary driver of this difference is that the IDP forecast is an aggregate of feeder peaks that are non-coincident with the system peak, while the IRP forecast is coincident with the system peak. Additionally, using slightly different vintages of forecasts, as referenced in Table E-3 (mentioned above) of our IRP, plays a role in the difference. It is important that the distribution system is planned to the non-coincident feeder peaks. In a given year, not all feeders experience peak demand at the same time, or even on the same day; however, the peak demand for each feeder represents the maximum utilization of that feeder throughout the year, which determines the capacity that the feeder must be capable of providing regardless of the loading other feeders may be experiencing at that time.

## XI. MISCELLANEOUS

### A. IVVO

Both Fresh Energy and GECs requested that the Company re-evaluate Integrated Volt-Var Optimization (IVVO), including updating our analysis and assumptions and exploring ways to deploy IVVO in environmental justice areas.

As directed in Order Point 36 of the Commission's July 17, 2023, Order in our most recent electric rate case (Docket No. E002/GR-21-630), our IDP included a discussion on IVVO and whether it is in the public interest (see *Appendix B1,* pages 28-32). The Company decided not to move forward with IVVO because it was opposed by most commenters in the 2019 IDP and the Commission also declined to certify the project. When we requested IVVO certification in 2019, our analysis showed that the modeled costs outweighed the modeled benefits even under the most optimistic sensitivity. Since that time, there have been other technology improvements and increased load from electrification, and as a result, we estimate that the benefits from IVVO are even lower today than in 2019. Therefore, we do not believe that it is prudent or in the public interest to pursue IVVO further or to devote any additional time and resources for updated analysis, reevaluation, or investigation.

We request that the Commission decline Fresh Energy's and GECs' recommendation to re-evaluate IVVO.

## B. Alternative Tariffs

The Department requested feedback on whether discussion of alternative tariff structures belongs in the IDP. The Company does not believe that discussion of alternative tariff structures belongs in the IDP, as the IDP is for distribution planning, not for requesting that the Commission approve tariff changes, funding, projects, or rate design. Minnesota Statute, the Department of Commerce, and the Minnesota Public Utilities Commission have already established processes for customer programs and tariff requests, and discussion of alternative tariff structures belongs in those venues.

We request that the Commission decline the Department's request to discuss alternative tariff structures in the IDP.

## C. Energy Conservation and Optimization (ECO)

The Company is not supportive of Fresh Energy's recommendation to add requirements to the Company's ECO programs through the IDP process. Fresh Energy has recommended a near-term goal to expand behavioral, price-based, and pre-emergency demand response programs and a medium-term action plan to expand locational dispatch capabilities. As discussed below, these types of programs exist and are discussed in a different docket. As the purpose of the IDP is not to seek approval for programs, this discussion should remain in the dockets mentioned below.

First, the Company has already filed and received approval of behavioral and price-based demand response programs in our 2024-2026 Minnesota Energy Conservation & Optimization Triennial Plan.[52] In total, the Triennial Plan includes five distinct programs including a behavioral component as well as a price-based pilot for commercial customers. Additionally, the Company has submitted a modification to the ECO Triennial Plan to continue our Peak Day Partners pilot and add a Battery Program[53] that would allow for the Company to begin to control at a more granular level.

Second, as explained in more length in Section II.B. above, to utilize locational dispatch and expand our demand response resources in this fashion, an Aggregator DERMS is necessary. The Company is already taking steps to move forward with opportunities presented by these technologies. The Company finds no reason to create an action plan already in motion.

We request that the Commission decline Fresh Energy's recommendation to add requirements to the Company's ECO programs through the IDP process.

## CONCLUSION

We appreciate the opportunity to provide these Reply Comments. We respectfully request the Commission decline:

- the Department's recommendation for the Company to provide a CBA for each grid modernization project in the five-year action plan;
- the Department's recommendation to provide a complete accounting of all historical and all anticipated future grid modernization costs with the IDP;
- the Department's recommendation to refile *Appendix C: Action Plans*;
- the Department's recommendations regarding DI investments, including the request to refile the proposal for DI with a complete CBA;
- recommendations by parties requesting the Company to conduct CBAs for discretionary projects;
- 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;

[52] See *In the Matter of Xcel Energy's 2024-2026 Energy Conservation and Optimization Triennial Plan*, Docket No. G,E002/CIP-23-92, Department of Commerce, DECISION (December 1, 2023).
[53] See Docket No. G,E002/CIP-23-92, Modification Filing, Xcel Energy, (February 27, 2024).

- the Department's recommendations regarding NWAs, including their recommendation that we be required to consider NWAs for all non-asset-based distribution system projects;
- the City of Minneapolis' request for a comment opportunity for any NWA RFPs;
- 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;
- 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;
- the Department's recommendation to have reliability metrics concerning FLISR reported in our IDP;
- the GECs' request that the Company reconsider the PNL methodology and specifically consider increasing the dependability factor or using seasonal/ differentiated dependability factors;
- Fresh Energy's and the GECs' recommendation to re-evaluate IVVO;
- Fresh Energy's recommendation to add requirements to the Company's ECO programs through the IDP process;
- the Department's request to discuss alternative tariff structures in the IDP.

Additionally, we 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:

- the Company's proposal to discontinue IDP Requirement 3.A.9. as requested in our 2023 IDP;
- 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;
- our proposed modification to Xcel Energy's IDP filing requirements to remove the requirement that financial information be reported in IDP-specific categories;
- 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 $D_{PV}$ in the next planning cycle for N-0 risk analysis; and

- the Company's 2023 IDP.

Dated: March 22, 2024

Northern States Power Company

## CERTIFICATE OF SERVICE

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

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

xx electronic filing

**DOCKET NO. E002/M-23-452**

Dated this 22nd day of March 2024

/s/

________________________________

Christine Schwartz
Regulatory Administrator

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