MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	January 20, 2022	Agenda Item 4**
Company	All Electric Utilities	
Docket No.	**E999/CI-16-521**	
	In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611	

Issues — Should the Commission order any of the suggested changes identified in the Distributed Generation Workgroup (DGWG)? The respective changes involve:

1. Group System Impact Studies
2. Interconnection queue management
3. DER dispute resolutions processes
4. Other issues related to the DER interconnection process

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Relevant Documents	**Date**
MN PUC, MN DIP v. 2.3 (attached to Commission Order)	April 19, 2019
Staff Briefing Papers, Summarizing DGWG Subgroups	May 12, 2021
MN PUC, Notice of Comment Period	July 16, 2021
Compliance Filings	
Xcel Energy (Q1)	May 17, 2021
Xcel Energy (Q2) Public Comments	August 16, 2021

MN PUC, C Burrow	June 28, 2021
MN PUC, D Holden	August 6, 2021
<u>Initial Comments</u>	
Institute for Local Self-Reliance (ILSR)	August 24, 2021
Department of Commerce	August 25, 2021
All Energy Solar	August 25, 2021
Interstate Renewable Energy Council (IREC), INC.	August 25, 2021
Nokomis Energy	August 25, 2021
Xcel Energy	August 25, 2021
Novel Energy Solutions with attachments A and B	August 25, 2021
Otter Tail Power Company	August 25, 2021
City of Minneapolis	August 25, 2021
Minnesota Power	August 25, 2021
Minnesota Solar Energy Industries Association (MnSEIA)	August 25, 2021
Fresh Energy with attachments 1-5	August 25, 2021
Dakota Electric Association	August 25, 2021
<u>Letters of Objection</u>	
Department of Commerce – Letter	September 24, 2021
MnSEIA, Fresh Energy, IREC	September 28, 2021
Xcel Reply to Objections	October 12, 2021
<u>Reply Comments</u>	
PUC – Pivot Energy *(dated August 25, 2021)*	September 24, 2021
Solar United Neighbors	September 30, 2021
ILSR	September 30, 2021
All Energy Solar	October 1, 2021
Nokomis Energy	October 1, 2021
MnSEIA	October 1, 2021
Xcel Energy	October 1, 2021
Novel Energy Solutions	October 1, 2021
Department of Commerce	October 1, 2021
IREC	October 1, 2021
Otter Tail Power Company	October 1, 2021
Fresh Energy with attachments 1 and 2	October 1, 2021
Dakota Electric Association	October 1, 2021
Minnesota Power	October 1, 2021
<u>Late Filed</u>	
Xcel Energy – Letter, MISO Affected System Study Agreement	December 17, 2021
Xcel Energy – Letter, DER Limits and Other Utilities	January 11, 2022

Contents

I. Statement of the Issues

Should the Commission order any of the suggested changes identified by the Distributed Generation Workgroup (DGWG)? The respective changes involve:

1. Group System Impact Studies (Cluster Studies)
2. Interconnection queue management
3. DER dispute resolutions processes
4. Other issues related to the DER interconnection process

II. Background

The May 12, 2021 Staff Briefing Papers summarize the Distributed Generation Workgroup (DGWG) progress discussed at the Commission's May 20, 2021 Agenda Meeting which resulted in the additional comments before the Commission in this proceeding.

On June 28 and August 6, 2021, the Commission received two public comments expressing frustration with delayed interconnection timeframes.

By August 25, 2021, Institute for Local Self Reliance (ILSR), Department of Commerce-Division of Energy Resources (Department), All Energy Solar (AES), Interstate Renewable Energy Council (IREC), Nokomis Energy (Nokomis), Xcel Energy (Xcel), Novel Energy Solutions (NES), Otter Tail Power (OTP), City of Minneapolis (City), Minnesota Power (MP), Minnesota Solar Energy Industries Association (MnSEIA), Fresh Energy, and Dakota Electric Association (DEA) filed Initial Comments. A public comment by D. Holden was also submitted.

Letters of objection to October 2021 implementation of two Xcel Energy proposals from initial comments were received. On September 24, 2021, the Department filed a letter objecting to Xcel Energy's proposal to pay up to $15,000 per customer for distribution upgrade costs for residential Solar*Reward customers going into effect without formal approval by the Commission. In reply comments, Xcel Energy withdrew early implementation in response to the Department's objection and asks the Commission to approve the proposal. On September 28, 2021, MnSEIA, Fresh Energy, and IREC jointly filed an objection to Xcel Energy's notice of intent, in Initial Comments, to implement the Company's Technical Planning Limit (TPL) by Oct. 1st. On October 12, 2021, Xcel Energy replied maintaining the Company had the authority to implement the TPL, but withdrew implementation until Commission review. Both issues are discussed further below.

Between September 24 and October 1, 2021, ILSR, AES, Nokomis, MnSEIA, Xcel, NES, Department, OTP, Fresh Energy, DEA, and MP filed Reply Comments. Pivot Energy and Solar United Neighbors (SUN) also filed comments.

Between December 17, 2021 and January 11, 2022, Xcel Energy filed two letters outside the comment period in this docket. The letters outlined the Company's plan and agreement with MISO on Affected System Study Agreements for Transmission Studies and provided additional detail, including other utilities and states' experience, with DER limits like the TPL.

Staff Summary of Key Concepts

Queues are addressed in MN DIP 1.8. A utility maintains a single, administrative queue of interconnection applications for review based on when a complete interconnection application was submitted, and may manage the queue geographically (e.g. feeder, substation). Queue position is used to determine cost responsibility for necessary upgrades and establishes conditional interconnection capacity for the customer contingent on meeting technical requirements. If the utility and customer(s) agree, interconnection applications for System Impact Studies may be studied in clusters; otherwise, they will be studied serially. MN DIP does not further clarify what studying either "in clusters" or "serially" means, and these are open, debated topics in this docket, specifically as it relates to Xcel Energy, as described later.

MN DIP Sections 2-4 and associated Attachments describe interconnection review and studies. A DER interconnection is screened (Simplified/Fast Track) or studied (**System Impact Study or SIS**) by the utility to identify potential safety, reliability or power quality concerns which can impact a local section of the utility's distribution system (e.g. secondary system or feeder) or the risk for impact, usually with larger DER or in aggregate with existing distributed generation, may occur at the substation which interfaces with the bulk electric system. If the review identifies potential impacts to another utility's distribution grid or the transmission system, the application undergoes an **Affected System Study**. Xcel Energy proposes implementing **mandatory cluster studies** in specific instances and filed an agreement between the Company and MISO for a **MISO Affected System Impact Study**.

Depending on the concerns identified, a utility may require changes with the interconnection application (e.g. reduced capacity, power factor changes) or the customer to pay for **distribution upgrades** (e.g. transformer, reconductoring, protection equipment). Depending on grid conditions, loading, existing distributed generation, and other factors, certain areas of a utility grid may have limited or no hosting capacity or **known capacity constraints** which increases the likelihood of the application triggering costly upgrades. An example that will be discussed later is Xcel's use of a **DER Technical Planning Limit** (TPL) which effectively limits the total capacity of a feeder or substation to a percent of the equipment rating plus the daytime minimum load (DML) with the intent of creating a capacity buffer. Xcel also discusses a policy to work under the DER TPL where the total available capacity is split between an **Open DER Capacity Limit** which encompasses all DER, and a **Small DER Capacity Reservation** which only encompasses DER under 40kW and that meet the 120% of onsite consumption rule.

Alternatively, a number of factors not related to grid capacity limits can result in large, local (feeder/substation) queues, such as incentive programs, neighborhood efforts, utility resource limitations, long timeframes for ahead in queue projects, etc. (**non-capacity constrained.)**

MN DIP requires interconnection customers to pay the actual costs of interconnection but allows for cost sharing under certain circumstances. Numerous parties offer **cost-sharing** proposals to allow for distribution upgrades to be recovered more broadly than solely from the individual interconnection customer whose project triggered the upgrade.

III. Party Comments

In this section, staff summarize the record covering six primary topics: a) interconnection queue management b) cluster studies; c) DER technical planning limit, d) small DER capacity reservation; e) cost sharing proposals; and f) dispute resolution. These topics are intertwined and party support or opposition to one topic may be conditioned on another topic. For instance, all parties support cluster studies in concept, but have not agreed on implementation details, guidelines, or assumptions. Relatedly, while many of the topics before the Commission have technical aspects, there are also policy considerations woven into the proposals offered by the various parties. Lastly, nearly all of the proposals are suggested for Xcel Energy and the Company's unique situation with significantly more DER both awaiting review and interconnected to their distribution system.

A. Interconnection Queue Management

On Hold and Interconnection Review

To date, most utilities are meeting or beating the MN DIP timeframes; however, Xcel Energy customers face longer timeframes in areas where either: 1) existing distributed generation or grid conditions results in capacity-constrained feeders and substations necessitating more complex utility study ("known capacity constraints") and/or 2) areas with high volume of new interconnection applications.

Xcel Energy instituted an "on hold" status for interconnection applications waiting in queue for sequential, rather than parallel, utility review. Xcel Energy pauses MN DIP review timeframes for these applications until the application is released from "on hold". As of October 2021, Xcel Energy reported 300 interconnection applications on hold – 59 were customer-sited solar and 241 were Community Solar Gardens (CSG).[1]

Fresh Energy offers the following analysis of "On Hold" Applications (as of August 2021) where MNDIA stands for an Interconnection Agreement:[2]

Table 1: August 2021 "On Hold" Lengths in Xcel Territory

Years until MNDIA for new applicant	Number of Substations	Number of Feeders	Number of Applications
Less than 4 years	42	59	83
4-8 years	13	16	87
More than 8 years	11	7	146
Total	**66**	**82**	**316**

Table 2: Size Range of Projects "On Hold" by Track

[1] Page 1: Xcel Reply (10/01/2021)

[2] Fresh Energy Initial, p. 7

MN DIP Process Track	Applications On Hold	Min. Capacity (kW)	Max. Capacity (kW)
Fast Track	110	23.51	1000
Simple	37	3.747	19.988
Study	169	1000	1000

IREC argues Xcel Energy's "on hold" approach is an "improper interpretation of MN DIP [resulting] in a massive queue backlog, with most projects in Xcel's queue facing substantial delays, in violation of MN DIP."[3] Solar developers and others agree.[4] AES notes, as of August 2021, the total number of Applications "on hold" had increased 86% since January 2021.[5] AES highlights impacts on several customers of errors in the Company's manual "on hold" implementation.[6] Nokomis proffers Xcel is underestimating MN DIP timeframe performance by omitting on hold projects in MN DIP quarterly reporting. If "on hold" projects were included, Nokomis argues Xcel's reported interconnection timelines would double.

Some commenters offer various timeframes for the Commission to require Xcel Energy to end the use of "on hold" treatment of applications:

- Nokomis suggests an immediate end[7]
- AES requests the Commission require Xcel Energy remove all customer-sited DER application from "on-hold" within three months.[8]
- IREC and Fresh Energy suggests a phase out within a year. Fresh Energy proposes quarterly compliance reporting[9], and IREC suggests aggressive action by the Commission if Xcel Energy does not comply.

Commenters offer many possible solutions for "on hold" projects: 1) parallel review; 2) earlier triggers to start next in-queue review; 3) review treatment dependent on whether the queue has a known capacity constraint or not; 4) mandatory group studies (discussed above); 5) more engineering staff; 6) proactive upgrades to the distribution system; 7) shortening the MN DIP allowable timeframe for a customer to sign the IA; and 8) requiring applications in known capacity constrained area to pay an additional fee.

Nokomis and others argue the MN DIP requires "serial" administrative queues, but parallel engineering study. Nokomis recommends revised MN DIP language for the Commission to clarify projects ahead in queue are to be treated as operating generating capacity – reverting to

[3] IREC Reply, p. 2
[4] Nokomis Initial, p. 2; Novel Energy Solutions Initial, pp. 2-4; MnSEIA Initial, p. 8; Fresh Energy Initial, pp. 7-8; Pivot Initial, p. 2
[5] AES Initial, p. 2
[6] AES Initial, p. 8
[7] Nokomis Initial, p. 2
[8] AES Reply, p. 8
[9] Fresh Energy Reply, p. 5: "add to its quarterly compliance filings in this proceeding a discussion of its work to implement the Commission's transition period directions, changes to known capacity constraints, the number of projects on hold in constrained and non-constrained locations, and any other relevant information."

how Xcel dealt with the queue prior to MN DIP.[10] Nokomis notes Xcel previously approved more Interconnection Agreements in a quarter than the Company does in a year under the MN DIP. See *Extend Parallel Review* below for more details.

MnSEIA and ILSR suggest hiring more engineering staff would help and acknowledge Xcel's increased staffing effort thus far.[11] NES notes a high level of staff turnover acknowledging Xcel interconnection engineers have been exemplary, but turnover results in constant rehashing of conversations and, occasionally, markedly different opinions.[12] ILSR and IREC both argue Xcel should do more to proactive rather than reactive planning for DER upgrades.[13]

Xcel Energy disagrees with commenters and notes ongoing Interconnection Applications in areas where the Company's hosting capacity maps show limited, or no capacity (red) and monthly queue reports list some areas face delayed interconnection review of multiple years. Xcel Energy maintains the change from parallel to serial review from pre-MN DIP to MN DIP applications is needed to prevent re-studies that waste engineering resources and result in inaccurate cost estimates. Further, Xcel argues the Company's serial review provides necessary information (load characteristics, location and operational characteristics of DER, etc.) and is consistent with the intent of the FERC Small Generator Interconnection Process (SGIP) language adopted in the MN DIP.[14] The Company cites a 2010 FERC Order for a similar issue at the transmission level confirming California ISO uses the same sequential review and moved to mandatory cluster studies.[15]

Xcel Energy identified actions the Company has taken to improve queue management to-date: 1) bringing in twenty new staff positions to work on DER process; 2) clarified engineering practices; 3) finalizing online application portal improvements; 4) publishing more data in the public queue about queue lengths; 5) updated website; and 6) allowing small, simplified interconnection applications (<40 kW) behind larger interconnection applications in the queue to move ahead if there are no material impacts to the projects ahead in the queue.[16] The Company is also working on hosting capacity analysis improvements; implementation of advanced inverters (discussed further below); and examination of high DER penetration technical issues with EPRI, industry experts, and stakeholders.[17]

The Department et al support Xcel Energy use of parallel review for eligible <40 kW Applications.[18] Other utilities do not object to Xcel Energy's approach, but do not support making it mandatory in the MN DIP. Dakota Electric, Minnesota Power, and Otter Tail Power note the current, serial review process in MN DIP works for the number of DER and

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[10] Nokomis Initial, pp. 2-4; NES supports at p. 1 of Reply.
[11] MnSEIA Reply, p. 3; ILSR Reply, pp. 4
[12] NES Initial, p. 12
[13] ILSR Reply, p. 5
[14] Pages 7, 11-12: Xcel Reply (10/01/2021)
[15] Page 8: Xcel Reply (10/01/2021)
[16] Xcel Initial, pp. 14-16
[17] Xcel Initial, p. 30
[18] Fresh Energy Initial, p. 8

Interconnection Applications they process.[19] If the Commission proceeds to require parallel review, Dakota Electric asks the Commission to consider a modification or clarification of the MN DIP with "particular attention… to the potential interaction of cost causation between smaller and larger DER projects within a parallel approach.[20]

The Department supports gathering more information about the impact of parallel processing for 40 kW and under projects, and proposes Xcel Energy track and report on:[21]

> a. Number of projects <40Kw that failed Initial Review Screens, Supplemental Screens, and required Upgrades by
>
> > i. Per quarter in the year before parallel screening was implemented;
> >
> > ii. Per quarter after parallel screening was implemented;
>
> b. Identify/tag applications screened in parallel;
>
> c. Additional analysis on the potential impact to interconnection costs of switching to parallel processing.

Extend Parallel Review

Fresh Energy and Nokomis suggest expanding Xcel Energy's parallel screening process to all Fast-Track projects (up to 5 MW) as soon as possible.[22] The Department and IREC support Fresh Energy and Nokomis's recommendation where there is no known capacity constraint.[23] Fresh Energy notes 53% of "on hold" applications are on non-constrained substations, and 114 of those applications are in queues of 8 or more.[24]

Xcel Energy opposes expanding parallel review to more projects arguing it will lead to increased restudies and wasted engineering resources. The Company highlights that, between 2015 and 2021, pre-MN DIP projects resulted in over 200 restudies (15% of all studies) with costs absorbed by all Xcel ratepayers.[25] Xcel states the Commission already recognized that accuracy was a tradeoff for speed, and that one of the MN DIP's intents is increased cost estimate accuracy.[26]

Nokomis disagrees noting developers pay for restudies under the MN DIP and over 700 MW of Community Solar Gardens pre-MN DIP were interconnected via parallel review. Nokomis suggests an additional fee to add a project to the queue at a constrained feeder would properly allocate development risk and streamline long queues on known capacity constrained feeders.[27] Xcel Energy notes after the IA is signed (trigger for next in queue review to begin)

[19] DEA Initial, p. 5; OTP Reply, p. 2; MP Initial, pp. 2-3
[20] DEA Initial, p. 6
[21] Department Initial, p. 4
[22] Fresh Energy Initial, p. 8 Nokomis
[23] Department Reply, p. 6; IREC Reply, p. 6
[24] Fresh Energy Reply, p. 2
[25] Xcel Reply, p. 11
[26] Xcel Reply, p. 11
[27] Nokomis Reply, pp. 6-7

some ahead-in-queue withdraw requiring restudy for the next project – 20 instances since MN DIP went into effect – and the Company absorbs the restudy cost.[28]

Trigger for Next In Queue Review (Semi-Parallel)

Some parties recognize an alternative to parallel review in areas of known capacity constraints may be warranted. Xcel defines "known capacity constraints" as substations where aggregate DER capacity is greater than or equal to 90% of the transformer rating, or feeders where aggregate DER capacity is greater than or equal to 90% of the feeder rating.[29] IREC notes capacity constraints consider both active and queued generation which means some early-in-queue projects may be able to proceed without triggering expensive upgrades. IREC recommends the Commission require Xcel to file an assessment addressing how much DER will cause capacity-constraint for each queue, what upgrades would be required to accommodate more DER, and an explanation of how the Company reached those conclusions. IREC argues this and party comment is needed to test Xcel's determination of what constitutes a capacity constraint.[30] Xcel Energy argues this theoretical analysis would not help and summarizes the resource-intensive analysis of mitigations for 95 feeders with no hosting capacity in the 2019 Hosting Capacity Analysis Report.[31]

The primary debate is what MN DIP step should trigger next in queue review: Interconnection Agreement signed or a complete System Impact Study or a step in-between. Today, Xcel Energy requires the ahead in queue to have signed the Interconnection Agreement to trigger review of next in the queue for all projects greater than 40 kW and smaller projects when there is a known capacity constraint. Xcel Energy believes waiting until the MN DIA is signed grants the level of certainty required to determine impacts and assignment of costs.

If parallel review is not reinstated, MnSEIA and Pivot Energy support moving the trigger to begin review on next in queue up to when the ahead-in-queue has a completed System Impact Study or begins the Facility Study and notes the latter should save approximately 64 Business Days (over 3 calendar months) per project.[32] Alternatively, setting the trigger at a completed Facility Study would shorten the current timelines by approximately 50 Business Days per project. IREC agrees an earlier trigger is needed and proposes the completion of the ahead-in-queue's System Impact Study as a "stopgap measure" to address a "crisis" with Xcel's current interconnection queues while working on the longer-term solution of mandatory group studies.[33]

Fresh Energy charts out queue management proposals by constraint status, application track, and a transition (2022) and longer-term (2023 and beyond) timeframe that include parallel screening, semi-parallel studies (triggered at delivery of SIS or final screens), one-by-one

[28] Page 6: Xcel Reply (10/01/2021)

[29] Xcel has explained that "transformer rating" does not necessarily mean the nameplate rating of the transformer. Instead, the rating is based on the limiting element, which may be a lower rating.

[30] IREC Reply, p. 9

[31] Xcel Reply, pp. 22-24

[32] Pivot Energy Initial, p. 2

[33] IREC Reply, pp. 2, 5-10

processing, and mandatory group studies.[34] The Department recommends adopting Fresh Energy's proposed semi-parallel process for interconnection applications where there is a known capacity constraint until a process for performing cluster studies has been finalized.[35]

Xcel Energy disagrees with all proposals for earlier triggers noting that starting engineering review when the IA has been presented (versus signed) would have resulted in 77 restudies.[36] As an alternative, Xcel Energy proposes to cut in half the timeframe for an Interconnection Customer to sign an Interconnection Agreement from 30 to 15 Business Days. Pivot supports this change.[37]

To reduce review timeframes and "on hold" applications, Xcel Energy offers cluster studies and three additional solutions that do not change serial review: 1) the DER technical planning limit; 2) the DER reservation cap on a feeder for future, small DER; and 3) a fund for up to $15,000 upgrades for small, residential DER using Solar*Rewards account.[38] These proposals are discussed below.

B. Cluster Studies

Xcel Energy describes cluster studies:[39]

> Cluster studies are a method of interconnection study in which several projects are studied simultaneously rather than in series, and where associated Distribution Upgrade and Network Upgrade costs (such as those in Attachment 6 to the MN DIA) are spread across the projects studied. Additionally, Cluster Studies may provide a step toward addressing the deep interconnection queues, delays associated with them, and significant upgrade costs that some DER developers are currently experiencing.

At the conclusion of the DGWG Cluster Study Subgroup from November 2020 to June 2021 the recommendation to the Commission was to wait until a cluster study pilot had been completed. However, Xcel claims that their "effort to facilitate a voluntary study pilot [has] not been fruitful".[40] In the period between the end of the DGWG and the end of the Initial Comment Period, Xcel changed their thinking – they now propose to amend the MN DIP to make cluster studies mandatory under certain conditions.[41] However, most of the parties in the record that had initial comments on the Cluster Study topic spoke mostly to the potential design, implementation, reporting, and concerns of a voluntary cluster study pilot run by Xcel. The parties addressed Xcel's mandatory cluster study proposal in their respective reply comments.

Cluster Study Pilot

[34] Fresh Energy Reply, pp. 3-4
[35] Department Reply, pp. 5-6
[36] Page 6: Xcel, Reply, 10/01/2021
[37] Pivot Energy, Initial, p. 2
[38] Xcel Reply, p. 3
[39] Pages 24-25: Xcel Initial, 8/25/2021
[40] Page 25: Xcel Initial, 8/25/2021
[41] Page 25: Xcel Initial, 8/25/2021

There was near unanimous support for the general idea of a cluster study process with shared study and upgrade costs. However, several parties (ILSR, NES, MnSEIA, Fresh Energy, and the Department) desired that the voluntary cluster study pilot include projects in capacity-constrained areas. They, along with IREC, believe that the pilot would not be very useful if the only areas studies were in the non-constrained areas. IREC supports omitting pilots altogether and mandating cluster studies in certain areas is the better route to take. IREC urges the Commission to adopt a group study process for certain queues while also exploring a proactive upgrade process.[42] NES and AES give general support to the positions of MnSEIA, Fresh Energy, and IREC.[43]

Fresh Energy requests that Xcel increase their reporting requirement to include the following:

> A compliance filing six months after the Order in this matter is published describing the participating applications, relevant feeder and substation characteristics, the time in which each phase of the study was completed, any group retention measures (deposits or penalties) used, the general cost allocation process used, and any disputes that arose.

In reply comments Xcel states that they are fine with these reporting requirements. [44]

Both Minnesota Power and DEA state that cluster studies seem to have promise, but they do not want to be involved in any changes to the MN DIP. Additionally, DEA expressed concerns over specific aspects of a group study approach. First, they are worried about free riders – specifically applicants that withhold their application until the upgrades paid for by a cluster study create more capacity for their project. The second is related to the cost allocation. If cost allocation is done based on DER kW rating as proposed by Xcel and discussed later, DEA asks about the “cases where same size DERs are in the study but one needs 2 miles of line rebuilt compared to .25miles”? They also worry about the cases when a cluster goes through the whole process but then one applicant withdraws their project leading to an upgrade cost that is not manageable by the rest of the remaining applicants.[45]

Xcel Mandatory Cluster Study Proposal

Xcel, like IREC and others, believes that mandatory cluster studies is a key part of the solution to long queues and projects in capacity-constrained areas that may have upgrades individual parties cannot bear alone. Xcel proposes three different types of cluster studies – Distribution Group Study, Transmission and Distribution Studies (TDS), and Voluntary Cluster Studies.[46] These studies are in addition to a MISO Affected System Impact Study (MISO ASIS). Xcel’s agreement with MISO on the MISO ASIS was included in the Company’s Dec. 17 letter in the docket.

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[42] Page 12: IREC, Initial, 8/25/2021
[43] Page 7: Novel Energy Solutions (8/25/2021)
[44] Page 9: Xcel Reply (10/01/2021)
[45] Page 14: Dakota Electric Association (8/25/2021)
[46] Attachment C: Xcel Initial (8/25/2021)

Distribution Group Study

The “Distribution Group Study” is aimed at projects in non-capacity constrained queues that do not currently risk exceeding the DER TPL capacity or the Open DER Capacity Limit for the respective feeder or substation. The main objective of these studies is to more efficiently work through the interconnection queue as well as to save time and enable cost sharing for upgrades. Key details of a Distribution Group Study are as follows:

- Projects would not trigger the DER TPL or the Open DER Capacity Limit
- Three or more applications in sequential order in the same queue[47]
- Projects must be greater than 40kW in size
- Upgrades are limited to the distribution system (e.g., feeder upgrades, Voltage Supervisory Reclosing (VSR))
- Excludes upgrades like substation transformer upgrades or new feeders

Xcel proposes editing the MN DIP, adding MN DIP bullets 1.8.3.1 - 1.8.3.3, which relates specifically to the “Distribution Group Study” cluster study. This specific language can be found in Attachment A of these briefing papers. Fresh Energy notes proposed language in MN DIP 1.8.3.3 is ad hoc with no guidelines or timeframes and unacceptable for the 296 applications (as of August 2021) that would meet Xcel’s criteria for this study.[48]

Transmission and Distribution Study (TDS)

Transmission and Distribution Studies are aimed at projects in capacity constrained areas that would trigger the DER TPL or Open DER Capacity Limit – cases where more substantial upgrades like a new feeder or substation transformer are required. Projects in these types of areas are where Xcel currently requires a “Phase 2” System Impact Study. Key details of a TDS:

- Project would trigger the DER TPL or Open DER Capacity Limit
- Projects may not be in the same queue, but are in a relevant geographic area
- The TDS is conducted once per year if two or more applications qualify
- If only one application over six months, it may be studied in a non-cluster format
- Considers capacity upgrades (i.e., new feeder bays, transformer replacements)

Xcel proposes editing the MN DIP, adding MN DIP 1.9 – 1.9.8, which would address these TDS studies. The specific language can be found in Attachment A of these briefing papers.

Voluntary Cluster Studies

At any point an Interconnection Applicant or group of Applicants may suggest a cluster study of two or more projects, including other in-queue applications. These cluster studies may be added to either the Distribution Group Studies or Transmission and Distribution Studies queues,

[47] Staff note: Page 5: Xcel Initial, Attachment C at 4.2(a) states five applications are needed. This should be clarified.
[48] Page 6: Fresh Energy Reply (10/1/2021)

but may not mix the application types or include DER applications below a 40kW nameplate rating.

Xcel Cluster Study Process and Guidelines

Xcel provided their guidelines to these studies in Attachment C of their initial comments. The process for each type of cluster study is summarized below.

<table>
<tr><th>Distribution Group Study</th><th>Transmission and Distribution Study (TDS)</th></tr>
<tr><td>- Xcel identifies Interconnection Applications that are eligible for a cluster study.

- Xcel provides a good faith cost estimate of the Cluster Study which includes the following steps of a Distribution Group Study:

- Step One of SIS
Completed in 30+ days
Cluster Study Step 1 SIS report
Within 10 days Active Cluster Study Projects choose to withdraw or continue with the study
- Step Two of SIS if required (repeat of Step One)
If there were no withdrawals after Step One proceed to Step Three
- Any withdrawals at this point result in a Cancelled Study

- Step Three (MN DIP Facilities Study)
Timeline: 45 days multiplied by # of projects
Allocates costs for association upgrades
- Xcel Provides MN DIA to each Project with indicative cost estimates

- Remaining applicants proceed to required upgrades or;
- Any withdrawals at this point result in a Cancelled Study</td><td>- Xcel identifies Interconnection Applications that are eligible for a cluster study.

- Xcel provides a good faith cost estimate of TDS Cluster Study which includes:
Substation and Transmission Study; and
Distribution Group Study
- Xcel conducts a Substation and Transmission Study
Timeline: Conducted once per year, no general timeframe for study completion given study scope variability
Xcel provides a Substation and Transmission SIS noting capacity constraints, continuity of service and transmission system upgrades with nonbinding, good faith cost estimate for capacity upgrades
Within 10 days, Active Cluster Study Projects choose to remain in the study or withdraw their applications
If any withdrawals, Xcel may conduct a second Substation and Transmission Study
- Xcel conducts Distribution Group Study for Active Cluster Study Projects as described in left column.</td></tr>
</table>

Key Considerations

The cost allocation for the SIS, Facilities Studies, and upgrades are to be allocated to each of the Active Cluster Study Projects based on a proportion of the kW AC nameplate capacity of each Interconnection Application to the total nameplate capacity of all Active Cluster Study Projects. Costs for metering and Interconnection Facilities (such as typically represented in Attachment 2 to the MN DIA) will be assigned directly to each Interconnection Application.

Xcel includes provisions within the cluster study guidelines that should an Interconnection Applicant withdraw their application after the first SIS report (Step One), the second SIS report (Step Two), during the Facilities Study (Step Three), or fails to timely sign and fund its MN DIA then the applicant will be barred from applying on the studied feeder for one year.
If any of the remaining Active Cluster Study Projects fail to timely choose to go forward with all of the cluster Upgrades, then the Cluster Study shall end with no useable results. The next in queue project(s) among the remaining Active Cluster Study Projects will then be studied under the serial review process.

Response to Xcel Proposal

There is widespread agreement for the idea of mandatory cluster studies. Most parties even claimed that cluster studies are one of the best long-term solutions to managing the queue and overcoming the challenge of costly upgrades. IREC, MnSEIA, Fresh Energy, NES, ILSR, and the Department all support the notion. However, there is also widespread agreement that Xcel's proposal won't work as written. The disagreements revolve around the studies not being codified in the MN DIP, Xcel having full discretion on the study design and implementation, a lack of clarity on timelines, cost allocation, and cost transparency.

Xcel Discretion; Call for Oversight

The primary issue amongst the parties is that the parameters and design elements of Xcel's proposal are not being added to the MN DIP and is instead listed in their Cluster Study Guidelines document in Attachment C in their initial comments. These guidelines are not set in stone and are subject to change at Xcel's discretion as time progresses. This includes being able to dictate which projects are subject to a group study analysis, determine how quickly customers have to comply with various tasks, and the ability to cancel a study at their discretion. IREC and Fresh Energy posit that the risk and uncertainty is too great with Xcel being in full control of the process. NES and MnSEIA don't trust Xcel to run the studies without Commission oversight.

Timeline, Cost Allocation and Transparency

One of the issues commonly cited in Xcel's proposal are the proposed timelines. IREC claims that they're undefined and subject to change and thus do not prove that the process would be timelier than the current process where projects are serially studied. [49] Several parties

[49] Page 3: IREC, Reply, 10/01/2021

supported the notion of having "defined timelines" decided during a Cluster Study DGWG process and then codified into the MN DIP. Additionally, IREC claims that the proposed cost-allocation method is unclear, specifically about the cases where projects drop out of the study before the study's completion.[50] The goal of greater clarity on cost-allocation was shared among many parties. Some parties request even greater transparency with regards to the itemized costs of upgrades.

Cluster Study Working Group

In order to resolve several of these issues that parties have with Xcel's proposal, many of the parties (Fresh Energy, IREC, MnSEIA, and the Department) suggest the Commission order the creation of a stakeholder Working Group dedicated to the design and implementation of cluster studies. The key topics that the parties wish to clarify in the Working Group include:

- Circumstance when utility is required to perform group study (IREC)
- Rules for how mandatory groups are formed (notice, timing, etc.) (IREC, Fresh Energy, Department)
- Description of the studies to be performed in a group study, including identification of when individual assessments may be required (IREC)
- Defined timelines for all utility and customer steps of the process, and definition of what happens if timelines are not met (IREC, Department, MnSEIA)
    - Timelines for group studies should be in alignment with those used by other states. (IREC)
- Description of what happens when projects drop out after the group study process has started. This includes defined opportunities for projects to drop out, and deposits or other penalties to deter dropouts later in the process. (Department)
    - Group Retention Strategies (Fresh Energy)
- Provisions for sharing of both study and upgrade costs (IREC, Fresh Energy, Department)
- Rules for how existing applications may be transitioned into the group study process and how the process may change after the initial queue backlogged is cleared. (Fresh Energy)

IREC asks the Commission to place a defined end-date on the working group, suggesting a 90-day period. MnSEIA suggests a 60-day period and the Department suggests either a 60-day or 90-day period. The Department suggests using a matrix to determine where there is and isn't consensus to help facilitate the process after which the matrix is presented to the Commission.[51] IREC and MnSEIA support a notice, initial, and reply comment period, and an agenda meeting to formally resolve the remaining issues.

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[50] Page 4: IREC, Reply, 10/01/2021

[51] Page 5: Department of Commerce Reply (10/01/21)

C. DER Technical Planning Limit

Xcel's current status quo allows DER interconnections up "to a point where reverse power flow … [reaches] equipment thermal limits by allowing DER to interconnect up to Daytime Minimum Load (DML) plus 100 percent of the equipment rating of either the substation transformer or feeder."[52] Xcel states that this practice runs the risk of "generation reaching the thermal limits of the system" should the system experience a drop in DML.

In order to achieve its obligation of providing adequate, safe, and reliable energy at reasonable rates Xcel claims that it needs more stability and flexibility on its system. In order to achieve this flexibility Xcel proposes a DER Technical Planning Limit (TPL) which caps the total capacity of a particular feeder or substation as a function of its respective equipment rating and DML. Projects that exceed the DER TPL can still be interconnected but would include upgrades to preserve the TPL.[53] Originally, Xcel proposed setting the DER TPL equal to just 75% of the equipment without account for DML. However, several parties objected to this and Xcel now proposes setting the DER TPL equal to 80% of the equipment rating plus the DML.[54]

$$DER\ Technical\ Planning\ Limit = (E_r \times 80\%) + L_{DML}$$

Where:
DER Technical Planning Limit = Maximum Allowed DER on Feeder or Substation Transformer
E_R = Limiting Equipment Rating
L_{DML} = Daytime Minimum Load

Xcel found that DML is variable in nature but on the majority of feeders and substations it accounts for 20% or less of the equipment rating. Xcel thus believes that setting the equipment rating in the DER TPL to 80% provides enough margin to avoid the majority of the risk[55]. Citing Minn. Stat. § 216B.01 and Minn. Stat. § 216B.1611, Xcel highlights that that the purpose of distribution interconnection guidelines is to "establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources." Additionally, the Technical Interconnection and Interoperability Requirements (TIIR) states that "the [utility] must maintain a level of engineering judgement in order to interconnect the wide range of technologies over a variety of Area EPS and DER characteristics and designs." Xcel argues these statutes and requirements justify modifying the Company's DER interconnection procedures and implement a DER Technical Planning Limit (DER TPL) without the need to edit the MN DIP.[56]

Xcel maintains they have this authority because the implementation of the DER TPL is engineering judgment and thus in the realm of their power to exercise.[57] In fact, Xcel had plans

[52] Page 18: Xcel, 8/25/2021
[53] Page 19: Xcel, Reply, 10/01/202
[54] Page 21: Xcel, Initial, 8/25/2021
[55] Page 20: Xcel, 8/25/2021
[56] Page 17: Xcel, 8/25/2021
[57] Page 14: Xcel Reply, 10/01/2021

to implement the DER TPL on October 1st, 2021.[58] In response, MnSEIA, Fresh Energy, and IREC filed a Letter of Objection on September 28, 2021 requesting the Commission stay the implementation of the DER TPL until it can be formally addressed by the Commission[59]. While Xcel maintains that they have the authority to implement the DER TPL without Commission approval, on October 12, 2021 Xcel responded to the objection and acquiesced with the request and suspended the implementation of Planning Limit.[60]

Xcel does think that parsing the DER TPL into "Open DER Capacity Limit" and a "Small DER Capacity Reservation", which will be discussed later, does have public policy implications, and thus requires an edit to the MN DIP.[61]

Response to Xcel Proposal

Many parties, including IREC, MnSEIA, Fresh Energy, AES, NES, the Department, Nokomis, and SUN, oppose implementation of the DER Technical Planning Limit as designed by Xcel. The reasons for their opposition are many but can be categorized into the belief that: 1) this change can't be unilaterally implemented by Xcel and warrants Commission approval, 2) Xcel has not provided enough technical justifications for the changes nor proved that the risks are significant enough to justify significant counter measures, and 3) that the change will significantly reduce the total DER capacity available. There are additional concerns as well as suggestions to better mitigate the risks offered by some parties. Minnesota Power thinks that a DER capacity planning limit of some sort is worth exploring but does not see it as an issue that needs an immediate Commission decision.[62]

Commission Permission

Several parties, IREC, MnSEIA, Fresh Energy, NES, and Nokomis, claim that Xcel does not have the authority to unilaterally implement a practice like the DER TPL without Commission permission. IREC states that the Commission recently approved and updated individual utility Technical Standards Manuals (TSM) in 2020 which established a process for submitting, approving, and updating the TSMs. IREC posits that the

> Commission emphasized that the establishment of significant technical standards and requirements … in the TSMs must be done through a process that allows 'interconnection customers to be able to access and voice concerns with a utility's TSM.' As a result, the Commission established clear requirements for updating TSMs that would ensure that the Commission, not Xcel, ultimately makes the formal determination on any significant technical standards (which should be memorialized in the TSM) that stakeholders object to.[63]

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[58] Page 5: Xcel, 8/25/2021
[59] Page 4: Letter of Objection, MnSEIA, Fresh Energy, IREC, 9/23/21
[60] Page 2: Xcel Reply to Letter of Objection, 10/12/21
[61] Page 23: Xcel, 8/25/2021
[62] Page 2-3: Minnesota Power, 8/25/2021
[63] Page 15: IREC, Reply, 10/01/2021

IREC goes on to say that they understand that utilities need some discretion when dealing with individual applications or faced with new technologies or circumstances but that the TPL is neither designed for an individual application nor a new technology or circumstance and thus requires revisions to the MN DIP, technical standards, and Commission approval.[64] Fresh Energy makes a similar point – that "interconnection standards and procedures are regulated by the Commission and previous Commission orders in this docket make it clear that changes to the MN DIP, TIIR, or a TSM must come before the Commission and are subject to review" citing the Commission's August 13, 2018 Order in the current docket.[65] Fresh Energy says that the TPL is a market-changing policy and should not be considered under Xcel's scope of engineering judgement." MnSEIA also claims that the TPL is a policy rather than technical issue.[66]

Additionally, Nokomis and MnSEIA cite that Xcel's attempt to implement the TPL without Commission approval is disrespectful to everyone who participated in the DGWG and "demonstrates the Company's disregard for stakeholder feedback and Commission oversight in this matter".[67]

In response, Xcel maintains that it has the ability to implement the TPL using its engineering judgement and obligation to provide safe, adequate, and reliable system and cites recent Commission action on Formal Complaints by DER developers (Docket No. 21-160 and 20-892).[68] The Company mentions that the distribution system has natural limitations and compares the need for the capacity margin granted by the TPL to the practice of having a reserve margin on the overall generation fleet that was deemed acceptable to the Commission in the 21-160 docket.[69] Xcel suggests that since it is an engineering judgement it must merely ensure the practice is not arbitrary or discriminatory, as outlined as a threshold by Commissioner Schuerger in Docket 20-892, and the Company believes that the TPL meets that threshold. Further, Xcel claims that the TIIR supports their position using the quote from the requirements:[70]

> "The Area EPS Operator must maintain a level of engineering judgment in order to interconnect the wide range of technologies over a variety of Area EPS and DER characteristics and designs. The Area EPS Operator shall follow applicable industry standards and good utility practice when applying engineering judgment"

Adding that the TIIR gives broad discretion to the Area EPS Operator to provide technical guidance

> "Where this TIIR document does not provide technical guidance, the Interconnection Customer needs to review the Area EPS Operator's specific TSM document, the Area EPS

[64] Page 16: IREC, Reply, 10/01/2021
[65] Page 8: Fresh Energy Reply, 10/01/2021
[66] Page 5: MnSEIA Comments Reply, 10/01/2021
[67] Page 7: MnSEIA Reply 10/01/2021; Page 5: Nokomis, Reply, 10/01/2021
[68] Page 15: Xcel Reply, 10/01/2021
[69] Page 14: Xcel, Reply, 10/01/2021
[70] Page 16: Xcel, Reply, 10/01/2021

Operator's web site, or contact the generation interconnection coordinator at the Area EPS Operator."

Using the decision from Docket 21-160 Xcel further emphasizes that the Commission has recognized that "the MN DIP does not require every practice of the Company be in the TIIR".[71] Nokomis disagrees with Xcel's interpretation of the August 13, 2021 Commission Order (Docket 21-160) arguing it "was not an invitation for Xcel to seize power from the Commission to establish industry-wide capacity constraints, simply by brandishing the words 'safety' and 'reliability.'"[72]

MN DIP Contradiction

IREC and MnSEIA point out a seeming contradiction regarding Xcel's assertion that the TPL does not require Commission approval or an update to the MN DIP.[73] MnSEIA posits that the Company is being "sly" by adding TPL language to Xcel's proposed MN DIP edits about cluster studies in their proposed MN DIP edits. MnSEIA continues that if the Company would not need to add the language "the overall DER Technical Planning Limit may be defined by the Area EPS Operator" if they in fact believed they did not need Commission approval. IREC claims this is another example of Xcel adding policy changes not designated in the MN DIP comparing it to their practice of "on-hold" and "Phase 2" studies and that the Commission should end Xcel's ability of acting outside of the Commission rules. In response, Xcel claims that the proposed modifications to the MN DIP relate not to the TPL as a whole but their "Open DER Capacity Limit" and "Small DER Reservation Capacity" policies that are housed within the TPL and require Commission approval.[74]

Reduction in Total DER Capacity

IREC, Fresh Energy, MnSEIA, AES, and SUN all express that the TPL would significantly reduce the total available DER capacity on the system.[75] Fresh Energy asserts that the TPL does not serve the MN DIP's goal to "give maximum possible encouragement of distributed energy resources consistent with protection of the ratepayers and the public."[76] Before Xcel revised their TPL to be 80% equipment rating plus DML, they had proposed 100% equipment rating minus the DML. Through an Information Request, Fresh Energy calculated that the total loss of capacity would be 13%. Responding to their new TPL specifications, MnSEIA states that subtracting a flat 20% of equipment instead of subtracting DML would be significantly more limiting.[77] IREC calculated that it would result in a reduction of total available capacity by 2-3 GW which they say was corroborated in Xcel's September 24, 2021 Office Hours where they

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[71] Page 16: Xcel, Reply, 10/01/2021

[72] Page 6: Nokomis Energy Reply, 10/01/2021

[73] Page 17: IREC, Reply, 10/01/2021; Page 6: MnSEIA, Reply, 10/01/2021

[74] Page 14: Xcel, Reply, 10/01/2021

[75] Page 13: IREC, Reply, 10/01/2021; Page 3: Solar United Neighborhoods, Initial, 8/30/2021; Page 1: All Energy Solar Reply, 10/01/2021
Page 17: Fresh Energy, Initial, 08/25/2021; Page 3: MnSEIA, Initial, 8/25/2021

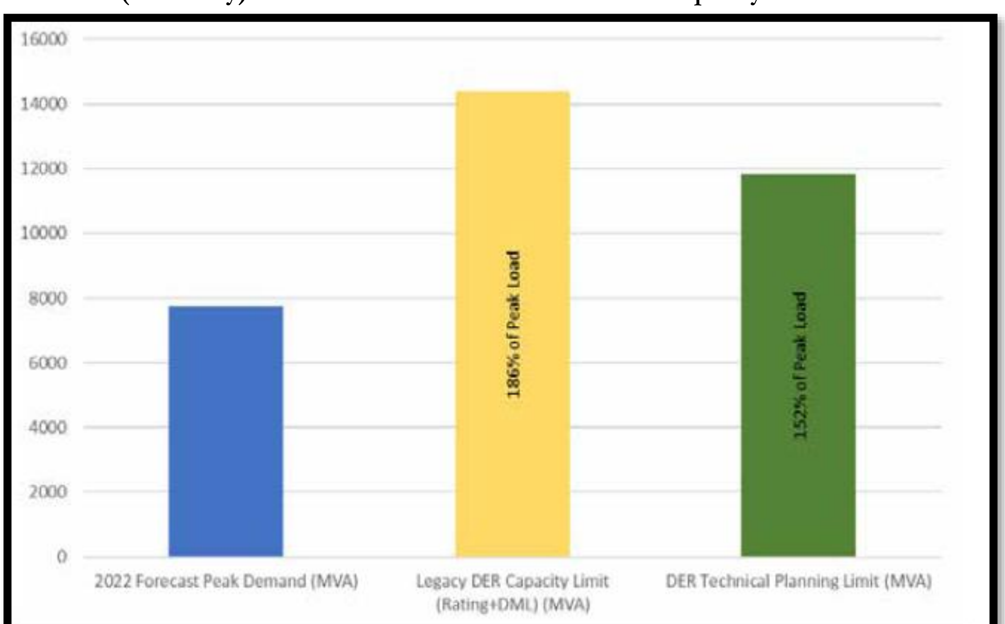
[76] Page 17: Fresh Energy, Initial, 08/25/2021

[77] Page 7: MnSEIA, Reply, 10/01/2021

referenced a 2.6 GW reduction.[78] Additionally, IREC offered the following chart to correct a "misleading" Xcel graphic used to represent the TPL that ignored the previous capacity of 100% equipment rating plus DML.

In response, Xcel disagreed with Fresh Energy's claim that the TPL is counter to the MN DIP's goals and state that when reviewing the impact of the TPL, it is necessary to look at the overall picture, not just the reduced megawatts.[79] Xcel acknowledged that there will be a net reduction in capacity without equipment upgrades but posits that the "real measure" should be how much load/demand can be served by DER. When the TPL is compared to demand, there remains more than enough DER capacity to serve load. Xcel points out that the potential interconnection of DER would cover around 152% of the forecasted peak demand.

NSP Load (MN Only) and Potential DER Interconnection Capacity



Technical Justifications

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[78] Page 13: IREC, Reply, 10/01/2021
[79] Page 20: Xcel, Reply, 10/01/2021

Xcel's main justifications for implementing the DER TPL is that in order to fulfill its obligation to provide its customers with safe and reliable energy and services they must reduce the risk of reaching equipment limits on the system due to DML loss, achieve more system flexibility, and mitigate the risk of curtailing installed DER. Xcel believes the TPL achieves these requirements. [80] The Company claims that with a DER TPL "the system will be less vulnerable to impacts from sudden changes in customer load, such as those that we have seen in some areas during the COVID-19 pandemic, or due to weather or energy-efficiency gains." [81] Xcel suggests that a TPL will eliminate "what if" scenarios and make the interconnection process more predictable.

In response, IREC, AES, Nokomis, NES, MnSEIA, and Fresh Energy all claim that Xcel has not provided enough technical justifications to warrant a system-wide capacity limit. The aforementioned parties understand that loss of DML and the need for operational flexibility are real issues and should be addressed in some capacity, but that Xcel has not demonstrated that they are occurring or that they are great enough to necessitate a 20% reduction in capacity across the board.[82] NES goes on to say that the margin appears to be arbitrary and capricious as Xcel has now changed the value more than once. NES stresses that "the impacts of this number have huge impacts on the program, as effectively the number selected is equivalent to the total capacity reduction of the entire program".[83]

Load Reduction

IREC claims that the risk of load reduction is the "only [issue] that Xcel [provided] any real explanation of in its comments" and IREC does not contest that this could be an issue. IREC does question if Xcel is responding to this risk in an appropriate way.[84] IREC asks the following questions to determine this question:

> Has there ever been a case where a sufficient amount of load has suddenly dropped off, causing existing generation to exceed the thermal ratings? Is there evidence that this is likely to occur in the future (if so, what is that evidence)? Finally, if it is likely to occur in the future, under what conditions and with what frequency? Xcel does not bother to address any of these questions in its comments.[85]

IREC goes on to point out that in Fresh Energy's IR 31 which asked how many times Xcel experienced a "reduction in load on the NSPMN system such that existing distributed generation exceeded the load on the circuit and caused a system impact that had to be remedied", Xcel's response was not able to point to a single time where load reduction resulted in generation causing a system impact because it does not track that information.

[80] Page 14: Xcel, Reply, 10/01/2021

[81] Page 15: Xcel, Reply, 10/01/2021

[82] Page 8: Fresh Energy, Reply, 10/01/2021; Page 2: All Energy Solar Reply, 10/01/2021; Page 6: Novel Energy Solutions, Reply, 10/01/2021; Page 7: MnSEIA, Reply, 10/01/2021

[83] Page 6: Novel Energy Solutions, Reply, 10/01/2021

[84] Page 20: IREC, Reply, 10/01/2021

[85] Page 20: IREC, Reply, 10/01/2021

In another IR 32, Fresh Energy found that 31 of Xcel's feeders experienced "decreases in DML over the past three years, ranging from -1kVA to -5,198 kVA [with] Xcel's typical feeder DML [being] 1,850 kVA."[86] IREC points out that in "none of these cases is Xcel saying the load drop caused generation to exceed the thermal rating of equipment or otherwise cause system impacts."[87] IREC also claims that it's not clear if these were sudden losses or if they were predictable and had potential to be planned for. Additionally, based on the information gathered from IR 32, Fresh Energy claims that it is highly unlikely that the typical feeder saw a 15-20% drop while some of the feeders likely saw DML drop by significantly more than 20%. Based on these findings, FE suggests that the TPL is too broad of a cut and a more precise measure is required to deal with the challenge.

Furthermore, IREC points out that in IR 34 Xcel said that it "does not forecast or estimate minimum load growth or shrinkage by feeder or substation" nor do it consider transportation and building electrification policies into considerations for load forecasts. Based on this information, IREC concludes that Xcel has no reasonable basis that load reductions will increase in frequency or magnitude in the future[88].

Operational Flexibility

Xcel compares the TPL's potential function to their distribution system planning practice of having a 25% feeder capacity reserve so that load can be shifted to other feeders during contingencies. Fresh Energy claims that this comparison is misleading because "reconfiguring feeders so that customers do not lose power during an outage or other contingency is a high priority"[89]. Whereas DER is "taken offline during outages or contingencies" and that DER customers are not requesting a change to that practice. IREC also believes that there are ways that reconfiguring on a case-by-case basis is the more precise method to achieve operational flexibility and that temporary curtailment in the case of an emergency would be preferrable to the TPL.[90]

Additionally, IREC casts doubt that the risks Xcel says they face warrant such a broad cut to the system and they must first prove that these risks are significant enough that they cannot deal with them on a case-by-case basis.[91] IREC suggest that Xcel could have proposed a TPL that varied by feeder and their respective loads and long-term DML reliability. IREC claims that there are ways to predict which feeders are at risk for load loss such as if it is a mixed feeder or highly industrial feeders. Xcel could also use available data to see potential energy efficiencies across feeder types and whether they'd be offset by load growth. Given their belief that DML can be predictable to a degree, IREC suggests that "it would be reasonable to assess any planning limit as a percentage of DML rather than the equipment thermal capacity. For example, if a feeder could reasonably be expected to have a 10% loss of load, then the planning limit could be 100% of equipment rating plus 90% of DML."

[86] Page 9: Fresh Energy, Reply, 10/01/2021
[87] Page 20: IREC, Reply, 10/01/2021
[88] Page 21: IREC, Reply, 10/01/2021
[89] Page 9: Fresh Energy, Reply, 10/01/2021
[90] Page 22: IREC, Reply, 10/01/2021
[91] Page 24: IREC, Reply, 10/01/2021

IREC emphasizes that they want further investigation to "determine the realistic level offload reductions that should be planned for, and whether or not those reductions would actually result in a risk to the distribution system by overheating conductors or transformer loss of life." IREC proposes that Xcel can simply continue to use the screens from the MN DIP and the System Impact Study to identify these types of risks.[92]

Alternative Solutions

AES supports the Commission hiring an independent third party to "evaluate Xcel's proposed TPL to ensure that it is justifiable and the best solution for a future where demand for DER is going to increase".[93] IREC makes a similar suggestion to investigate whether the risks are substantial and whether a broad tool like the TPL is the best solution.[94] AES also points to other areas of the country where this issues has been navigated giving an example of Massachusetts working with battery manufacturers to create a program called ConnectedSolutions which allows utilities to access the battery systems of residents and businesses to help offset reduce peak energy demand. They also point to Xcel's operation in Colorado where they practice pairing battery storage with renewable energy.

Dakota Electric, AES, and Novel Energy Systems all suggest that this type of capacity issues could be better dealt with by being more proactive with their distribution upgrades via the IDP process.[95] NES claims that whatever DER considerations Xcel has been making in its IDP process, it has "not resulted in sufficient investment in capacity constrained areas before they became constrained." NES says, "the Commission must ensure that Xcel is appropriately considering load growth ***and*** local desires for self-generation." IREC, Fresh Energy, and MnSEIA have similar sentiments that Xcel must be more proactive via the IDP process although not in direct reference to the TPL proposal.

As mentioned earlier, Fresh Energy and IREC believe temporary curtailment would be a better alternative than implementing the TPL. Lastly, Fresh Energy says that it may be worth establishing a DGWG on the topic to explore the risks currently faced and the impacts and effectiveness of the proposed TPL[96]

IREC goes on to claim that Xcel creating a planning limit "reveals underlying inadequacies in Xcel's technical capabilities when it comes to reviewing interconnection applications."[97] IREC posits that Xcel's position that the TPL will make the interconnection more streamlined and predictable is just another way of saying the process will be easier because the TPL will "ensure that fewer projects have an opportunity to interconnect." IREC believes that the MN DIP, modeled after the FERC equivalent, had drafted timelines for projects much larger and more complex than the ones Xcel is seeing and it is Xcel's lack of staffing capabilities and expertise

[92] Page 25: IREC, Reply, 10/01/2021
[93] Page 2: All Energy Solar Reply, 10/01/2021
[94] Page 25: IREC, Reply, 10/01/2021
[95] Page 6: Novel Energy Solutions, Initial, 8/25/2021; Page 8: Dakota Electric Association, Reply, 10/01/2021; Page 2: All Energy Solar Reply, 10/01/2021
[96] Page 9: Fresh Energy, Reply, 10/01/2021
[97] Page 26: IREC, Reply, 10/01/2021

causing delays and missed timelines. IREC recommends, a recurring theme from parties throughout this docket, that the Commission require Xcel to acquire the staffing and technical capabilities to meet the required timelines.[98]

TSM TIIR Transparency

IREC states that Xcel may find it not necessary to "include its own technical policies in the TIIR or TSM because they have largely focused to date on the requirements for the interconnection customer connecting to the distribution system."[99] But IREC asks that the Commission "consider what is accomplished by not requiring clear publication and an opportunity for Commission review of significant, and non-standard, technical policies such as [the TPL]." IREC points out the Docket 20-892 order on April 16, 2021 required the formation of DGWG to discuss:

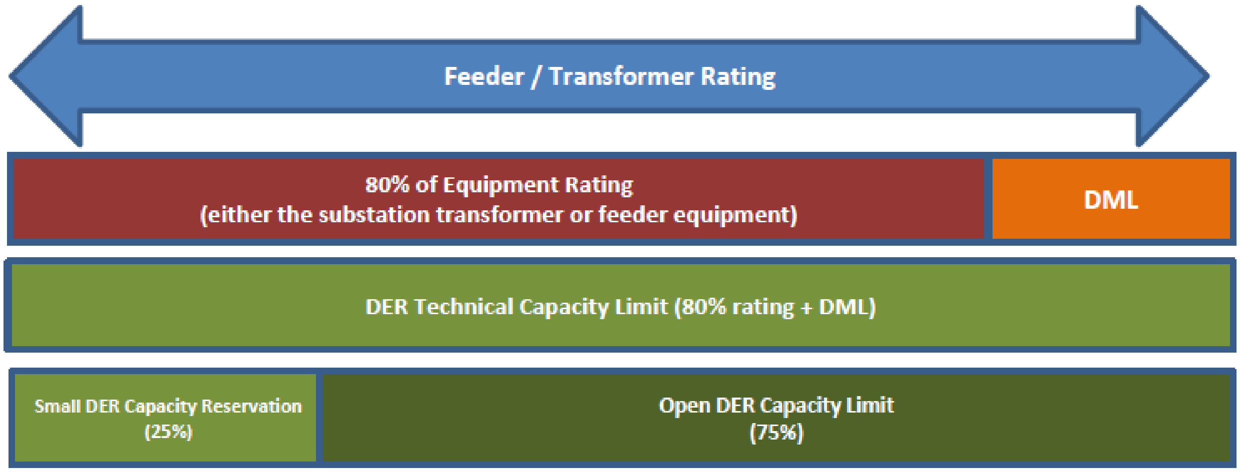
> "More transparent communication about how Xcel's distribution system design standards, policies and business practices related to distributed energy resource interconnections constitute good utility practice; including rationale when updates or changes to the standards, policies, or business practices occur. The subgroup should consider at a minimum: referencing in the Technical Specifications Manual, publishing on the website, and/or hosting trainings of developers among other options."

IREC states that there was no consensus on this topic and suggests that the Commission decide on how best the communicate these policy changes and to give the Commission the chance to evaluate the reasonableness of the changes.[100]

D. Small DER Capacity Reservation

Once Xcel has implemented the DER Technical Planning Limit, it proposes to then break down the total TPL into two segments – 75% for the "Open DER Capacity Limit" and 25% for the "Small DER Capacity Reservation".[101] The "Open DER Capacity Limit" portion would allow for interconnection of DER systems of any size and the "Small DER Capacity Reservation" (Small DER) portion would allow for DER systems under 40kW that comply with the 120 percent rule.[102] The proposed MN DIP changes for this policy are in Attachment A. Xcel maintains that while the DER TPL is a technical change, and thus does not need a MN DIP modification, the Small DER reservation has policy components and so does require a MN DIP change.[103]

[98] Pages 27-28: IREC, Reply, 10/01/2021
[99] Page 16: IREC, Reply, 10/01/2021
[100] Page 17: IREC, Reply, 10/01/2021
[101] Page 21: Xcel, Initial 8/25/2021
[102] Page 21: Xcel, Initial 8/25/2021
[103] Page 23: Xcel, Initial 8/25/2021



Xcel points out that large solar installations have continued to expand in Minnesota and that various state policies and market conditions are driving growth of larger DER systems like community solar gardens. The Company reiterates that one of its goals for interconnection is to "facilitate fair and equitable interconnection of all sizes of DER" and the Company worries that due to the policy and market forces driving CSG growth, smaller DER may "effectively be squeezed out of the market and prevented from being installed on specific feeders."[104] Xcel says that they have made improvement to this process by evaluating smaller systems simultaneously (parallel review) when there is no material impact on those projects that are ahead in queue which has helped on most feeders. However, some areas, like Northfield, are full and even Small DER must be put on hold and may have substantial upgrade costs in order to interconnect. Xcel wants to prevent more cases likes Northfield from happening and believe a Small DER Capacity Reservation is a viable solution.

Xcel claims that "the Commission has the authority and responsibility to establish a Small DER Capacity Reservation."[105] Xcel believes that "without explicit parameters that allocate the capacity, the first projects to saturate a feeder with DER would prevent others from installing DER on a given feeder, without incurring significant costs" and that the Commission's quasi-judicial and quasi-legislative role allows the Commission to decide these parameters. Xcel adds that "under state statute, 'rates' … shall not be unreasonably preferential, but 'any doubt of reasonableness should be resolved in favor of the consumer.'"[106] Xcel goes on to say that failing to act in a timely way would effectively be favoring Community Solar Gardens over Small DER.

Response to Xcel's Proposal

IREC, DOC, AES, Nokomis, NES, MnSEIA, Minneapolis, and ILSR oppose implementation of a Small DER Capacity Reservation as proposed by Xcel. The reasons why include the belief that it is unnecessary, discriminatory, reduces even more capacity for CSG, and that the cap is too arbitrary/not justified and too broad of a solution for what it is believed to be a narrow problem.

[104] Page 22: Xcel, Initial 8/25/2021
[105] Page 24: Xcel, Initial 8/25/2021
[106] Page 24: Xcel, Initial 8/25/2021

Some parties, like IREC, NES, and FE, are not against a reservation cap in principle but don't believe that Xcel has proven that a cap is necessary, why it must be so large, or why it is better than other proposed solutions.[107] IREC claims that Xcel has not given a good enough reason to justify why 25% specifically was chosen for the reservation cap and that it is likely substantially more capacity that is necessary.[108] MnSEIA echoes that this number appears arbitrary and blunt.[109] Fresh Energy states that when combined with the TPL, total capacity for open DER on a typical feeder would be reduced by 37.5%.[110] The City of Minneapolis, NES, MnSEIA, and IREC also believe the loss of capacity for open DER would be too great for the solution Xcel is trying to solve.[111]

Additionally, Fresh Energy and MnSEIA say this policy is not properly balancing needs of different DER market segments and should be more tailored to "load [conditions] and DER forecasts and other anticipated changes in electrical conditions, and adjusted to the characteristics of each substation and feeder."[112] IREC even claims that the proposal "is facially discriminatory in its intent to exclude certain customers from this opportunity" and Fresh Energy offers similar sentiments.[113] NES posits that the proposal "pits community solar garden developers against on-site developers when there are other approaches that can result in a more collaborative resolution."[114]

MnSEIA, Fresh Energy, and ISLR find the proposed cap to be unnecessary and too blunt when compared to other solutions.[115] The Department also claims that the reservation capacity limit is unnecessary or will fail in its goal. The Department says that where "capacity is already constrained, the Department does not expect reserving capacity for smaller projects will reduce the constraint, and where capacity is not constrained, reserving some for smaller projects appears unnecessary."[116] Fresh Energy supports this statement and says that in practice this policy would create a second queue for reserved capacity.[117]

In response, Xcel acknowledges that some areas are already too constrained for the capacity reservation but that their intent to prevent more areas from getting to that point.[118] The Company goes on to say that "implementing this change will provide for a fair and equitable

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[107] Page 19: Fresh Energy, Initial, 8/25/2021; Page 6: Novel Energy Solutions, Reply, 10/01/2021; Page 32: IREC, Initial, 8/25/2021
[108] Page 29: IREC, Reply, 10/01/2021
[109]Page 7: MnSEIA, Reply, 10/01/2021
[110] Page 10: Fresh Energy, Reply, 10/01/2021
[111] Page 1: Minneapolis, Initial, 8/25/2021; Page 6: Novel Energy Solutions, Reply, 10/01/2021; Page 7: MnSEIA, Reply, 10/01/2021; Page 28: IREC, Reply, 10/01/2021
[112] Page 20: Fresh Energy, Initial, 8/25/2021; Page 12: MnSEIA, Reply, 10/01/2021
[113] Page 29: IREC, Reply, 10/01/2021; Page 20: Fresh Energy, Initial, 8/25/2021
[114] Page 5: Novel Energy Solutions, Initial, 8/25/2021
[115] Page 7: MnSEIA, Reply, 10/01/2021; Page 3: Institute for Local Reliance, Reply, 10/01/21; Page 10: Fresh Energy, Reply, 10/01/2021
[116] Page 3: The Department, Initial, 08/24/2021
[117] Page 10: Fresh Energy, Reply, 10/01/2021
[118] Page 28: Xcel, Reply, 10/021/2021

opportunity for most of our customers to interconnect DER systems in areas where these conditions do not already exist."

Xcel also claims that tailoring the TPL and Small DER reservation to individual feeders and substations is very difficult because it is challenging to project DER growth on that granular of a level. They claim that there are some models as discussed in their 2019 IDP Initial Filing but that these models also have several shortcomings, including "including the challenges in making granular adoption forecasts for individual circuits, challenges in verifying consumer behavior, and scarce information about the physical premises that impact actual potential."[119] Instead, the Company believes that the Small DER capacity reservation combined with the DER TPL addresses "concerns regarding specific review based on characteristics of each substation and feeder" and that the TPL uses the "actual equipment ratings at a specific location."

Some parties, like DEA, NES, and AES, all believe that this policy would only be a temporary solution and that the capacity would eventually fill up and the area would face an upgrade that is too costly to overcome.[120] Additionally, AES claims that in the scenario where CSG fills up the 75% of the TPL before the reservation capacity, then voltage issues, rather than thermal issues will be the challenge and a reservation capacity does not address this challenge.[121] Fresh Energy, NES, and DEA believe a better approach would be proactive infrastructure investment through the IDP.[122]

AES again recommends hiring a 3rd party to investigate if this solution is the most proper to address the issue.[123] Xcel responded to AES the record is sufficient and the Commission has enough information to make a decision.[124] Nokomis states that a capacity reservation is not a real solution as it is a response to the issues caused by Xcel's "on-hold" process and that the policy is Xcel's attempt to "codify what the "on-hold" process is attempting to do: dramatically slow further deployment of DER in Minnesota."[125]

E. Cost Sharing Proposal

Three separate cost sharing proposals were offered:

- Xcel Energy proposes using Solar*Rewards funds for certain customers' distribution upgrades.;
- Fresh Energy, IREC and TruNorth propose an applicant fee (based on kW) for all small DER that is pooled to fund distribution upgrades;

[119] Page 21: Xcel, Reply, 10/021/2021
[120] Page 6: Novel Energy Solutions, Initial, 8/25/2021; Page 3: All Energy Solar, Reply, 10/01/2021; Page 6: Dakota Electric Association, Initial, 8/25/2021
[121] Page 3: All Energy Solar, Reply, 10/01/2021
[122] Page 10: Fresh Energy, Reply, 10/01/2021; Page 6: Novel Energy Solutions, Initial, 8/25/2021; Page 6: Dakota Electric Association, Initial, 8/25/2021
[123] Page 3: All Energy Solar, Reply, 10/01/2021
[124] Page 29: Xcel, Reply, 10/021/2021
[125] Page 4: Nokomis Energy, Initial, 8/25/2021

- Dakota Electric outlines an ongoing monthly capacity or energy based fee for DER customers to recover proactive and needed upgrades for DER.

Xcel

Xcel proposes up to $15,000 per new, residential Solar*Rewards interconnection application for distribution upgrades using Solar*Reward funds. The Company proposes an annual budget of $250,000 based on recent experience and expects to fund roughly 50 projects at an average cost of $5,000. Under this program Xcel will "fund the 'shared' system components such as transformers, which generally serve more than one customer" otherwise known as Distribution Upgrade costs as defined by the MN DIA attachment 6.[126] Likewise, "customers who require an upgrade to their Interconnection Facilities (MN DIA attachment 2), such as individual residential service lines, metering, etc., will continue to be required to pay the full cost of those upgrades as they do today."

When the Company proposed this change via the Solar*Rewards program's negative check off provision, the Department objected and sought Commission consideration. MnSEIA supports this approach and extending the budget with cost recovery through the rate base but wants more consideration of the $15,000 limit. MnSEIA notes without legislation Solar*Rewards funding will sunset in 2024 and drop by half to $5 million in 2023.[127]

Xcel posits that this program will require a new provision to the Solar*Rewards tariff and will be inserted on tariff sheet 9-49:

> g. For projects Deemed Complete on or after October 1, 2021, notwithstanding the requirement to follow the MN DIP, a Solar*Rewards application for a residential customer for a customer who is on a residential electric rate (including A01, A02, A03, or A04) does not have to pay the following interconnection costs up to a cap of $15,000 per premise: Distribution Upgrade costs that would otherwise be associated with Attachment 6 of the MN DIA; and, transformers shared by one or more other customers that may otherwise be associated with the Interconnection Facilities in Attachment 2 of the MN DIA. To the extent the costs associated with this provision exceed those expected by the Company in aggregate in a given year, the Company has the discretion to require a customer to pay for such Distribution Upgrade costs.

Response to Xcel Proposal

The Department is against Xcel's proposal because they believe that all of Xcel's customers should not be subsidizing Xcel's solar customers.[128] While the Department recognizes that there are some environmental benefits that benefits all customers, the economic benefit from rooftop solar installation goes to the customer installing the generation.

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[126] Page 28: Xcel, Initial, 8/25/2021

[127] Pages 8-9: MnSEIA Reply (10/1/2021)

[128] Page 4: Department of Commerce, Reply, 10/01/21

MnSEIA applauds this proposal and supports allowing the utility to rate base the upgrade costs because MnSEIA believes that it would "encourages residential and small business customers to install distributed generation (DG) and DER, and recognizes the system-wide benefits of DG and DER."[129] However, as with other parties, MnSEIA thinks that all system-wide upgrades for small projects should be eligible for utility funding. In the absence of a proposal that would cover all small DER, MnSEIA supports Fresh Energy's proposal. MnSEIA goes on to say that if both Xcel's and Fresh Energy's proposals are approved, then Fresh Energy's proposal should be amended to account for all non-Solar*Rewards projects and have the interconnection fee proportionally reduced.[130] Lastly, MnSEIA requests that Xcel substantiate how they came up with $15,000 as the upper limit for the proposal.

Fresh Energy says that it could support Xcel's cost-sharing proposal if it was accompanied by some transparency measures but also has some concerns about the longevity of the proposal if it's tied to Solar*Rewards as well as the proposal limiting customer eligibility.[131] NES supports Xcel's cost-sharing proposal generally but has a few questions about its parameters.[132] In addition, NES questions why the Solar*Rewards proposal is intertwined with the DER TPL stating that the cost-sharing proposal should not be held back by trying the approve TPL.

All Energy Solar also believes they could support Xcel's proposal with some key changes to it and also has some similar concerns to Fresh Energy.[133]

On equity concerns, Fresh Energy thinks that both proposals (Xcel's and Fresh Energy + IREC) increase access to customer-sited DER to all potential customers but especially the low-income DER customers. Fresh Energy also points out that under Xcel's proposal the cost of the Solar*Rewards upgrades is shifted to Xcel's full customer base. IREC and the Department echo these concerns questioning if it's the most equitable use of those funds.[134] FE points out that solar customers in Minnesota tend to be higher income and the portion of the Solar*Rewards program that is income-qualified is small, meaning that the higher-income solar customers may be subsidized by the Xcel's full customer base. However, Fresh Energy does say that the total "cost of the program is quite small compared to Xcel's overall distribution budget."[135]

Eligible Customers

Fresh Energy points out that while tying the proposal to the Solar*Rewards program may help streamline administrative tasks and communication, the Solar*Rewards program does have a sunset date with AES and MnSEIA also sharing this concern.[136] IREC asks the Commission to establish a "more agnostic program" due to the fact that Solar*Rewards is not guaranteed to

[129] Page 8: MnSEIA, Reply, 10/01/2021
[130] Page 9: MnSEIA, Reply, 10/01/2021
[131] Page 11: Fresh Energy, Reply, 10/01/2021
[132] Page 5: Novel Energy Solutions, Reply, 10/01/2021
[133] Page 4: All Energy Solar, Reply, 10/01/2021
[134] Page 30: IREC, Reply, 10/01/2021; Page 4: Department of Commerce, Reply, 10/01/21
[135] Page 11: Fresh Energy, Reply, 10/01/2021
[136] Page 9: MnSEIA, Reply, 10/01/2021; Page 4: All Energy Solar, Reply, 10/01/2021

exist in perpetuity.[137] Fresh Energy also distinguishes that under Xcel's proposal all it is only the residential Solar*Rewards customers who are eligible and not other segments of the Solar*Rewards program like non-profit, multi-family, or CSG, nor are other customers who would otherwise qualify but are not a part of the Solar*Rewards program. MnSEIA and NES concur with that sentiment and questions if those DER could be included into Xcel's eligibility.[138] Fresh Energy acknowledges that some proposed changes to the Solar*Rewards program would reduce the production incentive and "thus allow the same budget to serve more customers, this may be a less acute concern going forward, but recently, incentives have often run out mid-year." The issue of running out of funds mid-year is something that AES is also concerned about.[139]

To balance these concerns, Fresh Energy questions whether any of these eligible criteria should be altered, whether $15,000 is the proper number, or if income-qualified customer should have a greater upgrade allowance. Fresh Energy proposes that their cost-sharing proposal may avoid these types of challenges as described but does have its own challenges like requiring yearly updates and tracking accounting processes and costs which may be administratively burdensome to Xcel. IREC also asks the Commission to "consider whether there is a more equitable approach [than under Xcel's proposal] that would enable a broader swathe of customers to reduce their bills through the use of solar energy."[140]

Additionally, IREC worries about the few projects that require an upgrade that $15,000 would not cover. IREC believes a cost-sharing proposal like their own and Fresh Energy's would be better capable of handling a situation like this but requests the Commission "establish a path forward to ensure that higher-cost upgrades can also be done."[141]

<u>All Energy Solar Proposal</u>

All Energy Solar wishes to expand the eligibility pool of Xcel's proposed cost-share program to include non-Solar*Rewards applications that meet similar eligibility criteria and to expand the 120% rule to 150% (AES claims Xcel's solar production calculation doesn't adequately account for shade or snow coverage).[142] Additionally, AES believes that "Xcel should not limit eligible customers to only those that applied for by a specific date" that all applications "should be eligible no matter what review stage the interconnection process they are in".

AES also requests that non-shared distribution upgrades be eligible under the proposal as well. AES submitted an IR to Xcel "asking them to provide a breakdown of the costs between shared and nonshared distribution equipment" but Xcel responded that they do not track that information and that it would be too burdensome for them to do so. In response, AES questions how Xcel justifies excluding those upgrades from the proposal. AES posits that the expanded customer and upgrade eligibility would not be excessive in cost relative to the budgeted

137 Page 30: IREC, Reply, 10/01/2021
138 Page 5: Novel Energy Solutions, Reply, 10/01/2021
139 Page 4: All Energy Solar, Reply, 10/01/2021
140 Page 31: IREC, Reply, 10/01/2021
141 Page 31: IREC, Reply, 10/01/2021
142 Page 4: All Energy Solar, Reply, 10/01/2021

$250,000 and $387,519 per year in the two cost-sharing proposals. Lastly, AES is in agreement with the Fresh Energy that under these proposals, a Facilities Studies will no longer be necessary, and Xcel should therefore forego the step in the MN DIP.
The redline edits to Xcel's Solar*Rewards proposal:

> *g. For an interconnection application Deemed Complete on or after October 1, 2021, notwithstanding the requirement to follow the MN DIP, a Solar*Rewards application for a residential customer who is on a residential electric rate (including A01, A02, A03, or A04) does not have to pay the following interconnection costs up to a cap of $15,000 per premise: Distribution Upgrade costs that would otherwise be associated with Attachment 6 of the MN DIA; and, distribution equipment shared by one or more other customers that may otherwise be associated with the Interconnection Facilities in Attachment 2 of the MN DIA. To the extent the costs associated with this provision exceed those expected by the Company in aggregate in a given year, the Company has the discretion to require a customer to pay for such Distribution Upgrade costs.*

In summary:

- All open, current, and future interconnection applications are eligible
- Eligible applications include both Solar*Rewards Residential and Commercial, as well as non-Solar*Rewards applications that are within 150% consumption offset
- Distribution equipment, both shared and nonshared are eligible
- Xcel will opt to forego a facilities study for these applications

If the Commission decides not to incorporate AES's edits, they ask the Commission to approve both Fresh Energy and Xcel's proposal. At a minimum, AES supports passing Fresh Energy's proposal.[143]

Fresh Energy, IREC and TruNorth

Fresh Energy along with IREC and TruNorth created a cost-sharing proposal that would charge a flat fee to each DER application under 40kW.[144] These parties agree that

> By pooling costs, DER customers that may be faced with large upgrade costs as a result of grid conditions may be able to move forward. This would reduce friction, delay, and queue churn, enable a streamlined facilities study process, and potentially allow these customers to interconnect in areas that currently have capacity constraints.

The goals of a cost-sharing program for small DER include: 1) reducing geographic disparities that currently exist in interconnection costs, 2) enable greater equity of access to on-site DER by reducing the potential barrier of high interconnection costs, 3) reduce disputes and enable streamlining of several interconnection process steps, 4) facilitate a faster-moving queue, less queue churn, and enable small projects to be screened in parallel with ahead-in-queue projects

[143] Page 6: All Energy Solar, Reply, 10/01/2021
[144] Page 11: Fresh Energy, Initial 8/25/2021

in a greater number of locations, 5) enable small projects to interconnect in some capacity-constrained areas due to greater latitude to accept upgrade costs.[145]

The pool of money gathered from the flat fee would be used to pay for "supplemental screening fees and distribution system interconnection upgrades aside from substation level equipment." Fresh Energy estimates that the total cost for all 2020 upgrades under this program would be $300,000-$455,000 with an initial fee of $100-$150 per application. Fresh Energy believes this is a reasonable fee and expects to update the total each year based on previous year costs and forecasted DER application for the following year. Additionally, Fresh Energy believes there may be a "timing advantage by enabling projects to skip the facilities study phase altogether" which would be a great benefit because "speeding the interconnection process for residential projects that are sized to load is a high priority for many DGWG members".[146]

Response to Fresh Energy Proposal

The Department prefers Fresh Energy and IREC's cost-sharing proposal over Xcel's because they think the costs are more directly assigned to the cost-causing group (solar installers).[147] Xcel believes that their proposal through the Solar*Rewards program is the appropriate way to support small residential DER development and oppose the proposal as suggested by Fresh Energy.[148] The company points out that by asking every small DER system customer to pay a fee to fund upgrades it "would result in having 99 percent of small DER system customers (based on Q2 2020 information) to pay for Distribution Upgrades that were never needed in order to subsidize projects for the one percent of projects that are being built in constrained areas." Xcel does not believe this to be a fair approach.

Additionally, the Company says that this proposal would be an administrative burden to run. The suggested holding and managing of disbursements, monitoring projects, and dedicating resources to estimating costs would be "unduly burdensome and costly to the Company."[149] Xcel also claims that this proposal "could also lead to short-falls or overages between collected and dispersed amounts that will require clear rules of the road to handle." The Company claims these requirements goes beyond their role as the interconnection agent and may even cost more to adequately run than the cost of the upgrades it's meant to facilitate.

Xcel says that the Facilities Study can't be skipped, as suggested by Fresh Energy, and that it is necessary step for the Company to complete field verification, design the system, verify costs, and complete the construction details necessary for interconnection".[150] But the Company does mention that the Facilities Study under its proposal would be intended to have a shorter overall timeframe but specific timelines would be difficult to establish due to the variable nature of distribution upgrades.

[145] Page 11: Fresh Energy, Initial 8/25/2021
[146] Pages 11-12: Fresh Energy, Initial 8/25/2021
[147] Page 4: Department of Commerce, Reply, 10/01/21
[148] Page 30: Xcel, Reply, 10/01/2021
[149] Page 30: Xcel, Reply, 10/01/2021
[150] Page 31: Xcel, Reply, 10/01/2021

The Department prefers Fresh Energy and IREC's cost-sharing proposal over Xcel's because they think the costs are more directly assigned to the cost-causing group (solar installers).[151] On the other hand, MnSEIA prefers Xcel's Solar*Rewards proposal and using the rate base to pay for distribution upgrades, but suggests the Fresh Energy et al. cost sharing model may also be needed.[152] Dakota thinks the Fresh Energy-IREC proposal is a good first step in addressing cost-recovery but believes it's too early to make a decision and suggest that more discussion is needed.[153] Specifically, the utility has concerns about the annual update to the interconnection fee – what if one year is greater or lesser than average due to some externality and likewise for the number of interconnections? DEA also says that it could cause other externalities like a rush for interconnections in December because of a greater fee the following year. Finally, they question if non-exporting systems will also be a part of the proposal.

Transparency Measures

Fresh Energy posits that regardless of how the cost-sharing proposal is funded (general distribution budget or DER customers) that increased transparency into the types and costs of upgrades are a must.[154] To do this FE proposes that the Facilities Study results include "itemized cost estimates for each major component of proposed distribution upgrades, network upgrades, and/or interconnection facilities" as well as indicate whether a "smaller system size and/or different settings would avoid the need for major upgrades and if so, identify that size or setting(s) and itemize the potential reduction in upgrade costs." These changes would take effect within 60 days of this order. Xcel would also provide a detailed report of the costs incurred and technical rationale for each upgrade should the Company seek cost recovery for distribution upgrades from Solar*Rewards customers or request to charge a fee to certain DER customers to cover interconnection upgrades. AES, IREC and the Department also support these transparency measures to keep utilities accountable and to prevent gold-plating from occurring.[155]

Additionally, the "Department recommends Xcel be required to take into account the depreciated value of existing equipment being replaced or upgraded as part of its estimate of the flat fee and be ordered to track and report all upgrades and associated costs for its Solar*Rewards program."[156]

IREC recommends the Commission first address the big picture of small project upgrade costs here to determine the best, overall path forward and then separately decide if Xcel's proposal adequately addresses the issue.[157] Ultimately, Fresh Energy and IREC strongly recommends the

[151] Page 4: Department of Commerce, Reply, 10/01/21
[152] Page 8: MnSEIA Reply (10/1/2021)
[153] Page 4: Dakota Electric Association, Reply, 10/01/2021
[154] Page 12: Fresh Energy, Reply, 10/01/2021
[155] Page 28: IREC, Initial, 8/25/2021; Page 6: All Energy Solar, Reply, 10/01/2021; Page 5: Department of Commerce, Reply, 10/01/21
[156] Page 5-6: Department of Commerce, Reply, 10/01/21
[157] Page 32: IREC, Reply, 10/01/2021

Commission adopt a cost-sharing solution for small projects and believes that either proposal is viable.

Proactive Upgrades

Both MnSEIA and Solar United Neighborhoods share a sentiment that upgrades "for behind-the-meter DER would be more properly accounted for in Integrated Distribution Planning, and should accordingly be incorporated into the utility's cost recovery mechanisms" and that "such a policy should align incentives, and would alleviate the friction between the utility and DER customers."[158] And that the policy should also "recognize the long-term need to invest in the dynamic, two-way grid that will support the DER needed to meet the state's clean energy goals."

The City of Minneapolis and the ILSR appreciate the intent of lowering the cost barrier for small DER with cost-sharing proposals but they question why Xcel is transferring the costs of upgrading their distribution system on to their customers.[159] The City goes on to say that it's most "economically efficient for the utility to maintain a grid that anticipates these customer and policy preferences rather than performing upgrades one by one" and that the "public relies on Xcel to invest in this critical infrastructure in a way that promotes the use of distributed energy resources and provides cost savings." ILSR echoes the City in asking "why should customer-generators bear these costs in the first place?"

Utilities
Minnesota Power is generally supportive of exploring cost-sharing measures but does not currently need such a system.[160] Otter Tail Power does not recommend any changes to the cost-causer methodology.[161]

Dakota Electric Association Cost Sharing Proposal

While DEA does not recommend adopting any cost-sharing proposal at this time, DEA did create a cost-sharing proposal for all DER projects. Dakota notes that the utility is currently in the "free capacity" phase of DER adoption and not yet in the situation of having to deal with high-cost transmission upgrades but is currently contemplating how to proactively approach the challenge.[162] Dakota believes that changing the process for how utilities are compensated for distribution system upgrades and annual system costs may be worth considering using the example of a monthly fixed or energy charge for excess energy exported to the distribution system may be a way to mitigate or resolve many of the current issues Dakota Electric and other utilities are facing while encouraging more DER integration and fairly allocating upgrade costs among DER applicants."

[158] Page 4: MnSEIA, Initial, 08/25/2021; Page 3: Solar United Neighborhoods, Initial, 8/30/2021
[159] Page 2: Minneapolis, Initial, 8/25/2021; Page 2: Institute for Local Reliance, Reply, 10/01/21
[160] Page 2-3: Minnesota Power, Initial, 8/25/2021
[161] Page 2: Otter Tail Power, Reply, 10/01/2021
[162] Page 6: Dakota Electric Association, Initial, 8/25/2021

DEA offers to alter how distribution upgrades are paid by allowing "the ability for a distribution utility to capitalize the costs of the distribution system upgrade, and then charging a monthly rate for the DER [itself]" rather than have the applicant pay upfront for just the equipment upgrade. The utility says this would "levelize costs to the consumer and DER developer."[163] Dakota claims this would support efficient planning. The utility points out that "presently, there is no recovery method for a utility to address both system deficiency needs and upgrades which support future DER interconnections." For example, "if the utility would upgrade a line or portion of their system ahead of time, when the DER application comes in, there is no method to recover the costs of the upgrade. The existing users of the distribution system will pay for 100% of an upgrade that they may not need." DEA proposes if utilities were "compensated by the DER systems in the same way that they are compensated by users of energy, then the utility would have support for planning and upgrading the system to support forecasted DER integration". DEA goes on to say that a monthly fee to all users a distribution system, including DER users, would ensure "everyone would pay their share."

Dakota reiterates that DER and Small DER interconnections costs do not end after installation. The utility emphasizes that

> "there are on-going distribution system costs caused by DER interconnection which are not recovered through a one-time interconnection payment. If these on-going costs are not considered, then other ratepayers will assume these costs and DER developers, and those members using DER, will not pay their fair share of costs."

F. Dispute Resolution Process

The Commission requested comment on whether any of the changes discussed by the DGWG were needed to the MN DIP Dispute Resolution Process (MN DIP 5.3). The MN DIP dispute process applies to all Interconnection Customers with 10 MW and less operating in parallel with the utility grid – from the homeowner to the CSG developer. While the MN DIP outlines a process similar to the 2004 interconnection standards of mediation prior to engaging the Commission, the MN DIP 5.3.8 allows either party at any time to file an informal or formal complaint before the Commission. An Independent Engineer dispute resolution project for Xcel Energy's CSG program was eliminated with the implementation of the MN DIP.

Not unsurprising given the increase in DER applications, higher DER penetration in areas, extended interconnection timelines, and the rollout of the new MN DIP process, informal DER interconnection complaints peaked in 2019 and 2021 saw an influx of docketed Formal Complaints by DER developers related to interconnection.

Two parties recommended new dispute resolution processes (Xcel Energy and MNSEIA) and other parties provide comment and modification on those proposals.

Xcel Energy Proposal

[163] Page 7: Dakota Electric Association, Initial, 8/25/2021

Xcel Energy recommends an edit to MN DIP 5.3.8 to require mediation prior to engaging the Commission and a time limit on disputes[164]:

5.3.8 After first complying with sections 5.3.1 through 5.3.7, ~~At any time,~~ either Party may file a complaint before the Commission pursuant to Minn. Stat. §216B.164, if applicable, and Commission rules outlined in Minn. Rules Ch. 7829. However, in no event may any complaint or dispute for any interconnection issue or alleged violation of MN DIP be filed with the Commission against the Area EPS Operator more than one year after the act or omission that forms a basis of the complaint or dispute.

Xcel proposes a two-track implementation of this change consistent with the proposal the Company made in response to the Commission's February 18, 2021 Order in the 2019 Quality of Service Plan (Docket No. E002/M-12-383):

- **Expedited process** of 10 business days for non-technical issues (e.g., program administration, application portal functions, and similar)
- **Regular MN DIP process** of up to 43 business days, with option for mutual extension, for technical and more complicated interconnection issues (e.g., review screens, study results, and required distribution system upgrades and their costs)

Xcel suggests both tracks begin with submitting an online Notice of Dispute form which would constitute the written notice required in MN DIP 5.3.3. The Company highlights the expedited process includes a conversation rather than relying on written communications, and new technology and staffing should reduce the timeframe for this process. Xcel notes the current process with written communications between the customer, CAO and Xcel can take 2-3 weeks.[165] If the dispute was not resolved within the business days of its track, then the Complainant could go to the Commission or Consumer Affairs Office (CAO) for assistance resolving the dispute. Xcel also requests a 1-year limitation to bring a dispute which MnSEIA agrees is reasonable and could reduce spurious and retaliatory complaints.[166]

All Energy Solar, Novel Energy Solutions, and MNSEIA all oppose Xcel's proposed expedited process, noting it does not resolve the underlying issues for complaints and adds administrative work and delay for the complainant.[167] MnSEIA highlights the Commission's February 18, 2021 Order (Docket 12-383) required Xcel Energy, in part, to work with stakeholders to develop a different mechanism or tariff, outside of the Company's Quality Service Plan (QSP) customer complaint metric, to resolve solar installation issues before they became QSP complaints – providing transparency for tracking and accountability to the MN DIP timelines.[168] MnSEIA argues Xcel's proposals lacks third party oversight, will lengthen timelines by adding extra hurdles before the CAO informal complaint process, and by only counting unresolved disputes

[164] Page 33: Xcel Initial (8/25/2021)
[165] Page 41: Xcel Reply (10/1/2021)
[166] Page 10: MnSEIA Reply (10/1/2021)
[167] All Energy Solar Initial, p. 6; Novel Energy Solutions, p. 9
[168] Page 9: MnSEIA Initial, p. 9

to the Company's customer complaint metric would result in less transparency and accountability.

The Department and Fresh Energy support an expedited process for non-technical issues and an online Notice of Dispute form, but, like MnSEIA and AES, not limiting the customer's ability to engage CAO early in the dispute process.[169]

If the Commission adopts Xcel's proposal, All Energy Solar recommends the Commission require Xcel to provide reports on the number of complaints received, types of complaints, time to resolve the complaint, and if the underlying issue was addressed. Xcel committed to similar monthly reports to CAO in their filing.[170] MnSEIA supports Xcel's proposed monthly summary of issues raised and what remains unresolved; however, not at the loss of CAO oversight of ongoing disputes. The Company intends for the expedited process to clarify what constitutes a QSP customer complaint and recognizes customers may choose to engage CAO directly.[171] MnSEIA counters "deferring the ability of interconnection customers to make a complaint places them on a lower tier than other utility customers."[172]

MNSEIA Proposal

MnSEIA offers a counter proposal that keeps CAO engaged throughout the dispute process:[173]

1) Submitted "Pre-Dispute Form" or "Request for Issue Resolution" that Xcel proposes mark the beginning of either dispute resolution track are also copied to the CAO;
2) CAO may intervene at any time in either track;
3) the "Interconnection Dispute Process – Technical" track not preclude the non-utility party from filing an informal complaint with the CAO at any time; and,
4) Expedited Process track may preclude CAO complaints until its conclusion.

Xcel counters that CAO oversight imagined in the MnSEIA proposal would remain in the Company's expedited process, but a fair dispute resolution process starts with parties attempting to resolve the issue before engaging mediation.[174] Xcel defers to CAO on whether being copied on ongoing conversations between the Company and customer is desired.[175]

Other Proposals

Otter Tail Power and Dakota Electric are not experiencing dispute resolution issues currently. Dakota Electric suggests the DGWG should continue to attempt to create an independent dispute resolution process for technical issues, noting:[176]

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[169] Department Reply, p. 6
[170] Page 7: All Energy Solar Reply (10/1/2021); Page 39: Xcel Reply (10/1/2021)
[171] Page 43: Xcel Reply (10/1/2021)
[172] Page 10: MnSEIA Reply (10/1/2021)
[173] Pages 12-13: MnSEIA Initial (8/25/21)
[174] Page 42: Xcel Reply (10/1/2021)
[175] Page 43: Xcel Reply (10/1/21)
[176] Dakota Electric Initial, p. 12; Reply, p. 5.

> [Dakota Electric] supports creating an independent, unbiased technical review process and a queue or policy review process, so that these issues can be addressed with decreased risks of appeal to the Commission.

NES recommends reinstating the Independent Engineer (IEs) dispute resolution process for technical disputes. Xcel opposes noting the difficulty the Department had securing IEs and the lengthy review of the dispute (up to nine months.)[177]

All Energy Solar suggests Xcel host monthly stakeholder meetings to discuss the underlying issues. Xcel Energy currently hosts quarterly discussions for on-site solar projects which is in addition to the CSG stakeholder workgroup. The Company also appreciated MnSEIA's suggestion for an informal survey and plans to incorporate one into the next meeting.[178]

G. Miscellaneous

Transparency – upgrade costs/Xcel-MISO Transmission

Upgrade Cost Transparency
Several parties have submitted that they want more transparency as well as oversight regarding the distribution upgrade costs Xcel says are required for interconnection. Fresh Energy claims that Xcel has not been consistent with information it does provide – sometimes Xcel will provide a cost for distribution upgrades, transmission upgrades, and substation-related upgrades while in most cases customers typically receive a very brief description of the upgrades that Xcel has deemed required and one total cost number for all of the work.[179] All Energy Solar claims that there are cost discrepancies for similar equipment upgrades between Xcel, other utilities, cooperatives, and municipalities where Xcel's pricing is "exponentially higher" than the rest. [180] Additionally, All Energy Solar states that there is a "serious discrepancies in costs" even between their Xcel-specific projects. All Energy Solar provided an attachment detailing the cost discrepancy they've experienced over the last two years.

Itemized

Fresh Energy, AES, and MnSEIA all support requiring Xcel to provide more detailed itemized cost estimates among other information to developers. Fresh Energy specifically asks the Commission to require that Xcel provide an itemized cost estimate for each major component of proposed distribution upgrades, network upgrades, and/or interconnection facilities as part of the Facilities Study results.[181] Additionally, they ask that Xcel provide information indicating if a smaller system size and/or different settings would avoid the need for major upgrades and if so, identify that size or setting(s) and itemize the potential

[177] Page 42: Xcel Reply (10/1/2021)
[178] Page 40: Xcel Reply (10/1/2021)
[179] Page 24: Fresh Energy, Initial, 8/25/2021
[180] Page 7: All Energy Solar, Initial, 8/25/2021
[181] Page 12: Fresh Energy, Reply, 10/01/2021

reduction in upgrade costs [182]. Fresh Energy requests that this information be required whether or not the upgrade costs are recovered by developers, Solar*Reward customers, or from rate payers.

AES requests the Commission play a more active role in ensuring fair pricing by requiring Xcel make the "data for the type of upgrades, itemized invoices, and length of time between the date of identifying an upgrade is needed, and the date of construction … readily accessible to the Commission for review at any time." [183]

Some parties posit that if one of the major cost-sharing proposals like those in the cluster study policy or in the proposals put forth by Xcel and Fresh Energy dedicated to the cost-sharing of small DER upgrades, that the cost for distribution upgrades must be much more comprehensive and detailed. Fresh Energy stated that this type of transparency is a requirement if any type of cost-sharing approach is implemented[184] and All Energy Solar has expressed similar sentiments.[185]

Xcel does not believe requiring itemized invoices, as requested by AES and Fresh Energy, is reasonable or in the public interest and that the Commission should deny this request[186]. Xcel claims that this type of information is commercially sensitive, and a part of confidential contracts negotiated with each of their suppliers, and that it would be a violation to these contracts should they reveal this information. They further explain that the materials purchased in these contracts are used enterprise-wide and not exclusively for the interconnection of CSG or DER projects. Xcel warns that breaking these contracts could result in higher costs to their entire customer base as well the developers.

Additionally, Xcel claims they already provide category-level invoice details for CSG-related projects and would be willing to provide similar information for other DER projects. Xcel says that the level of information sought by commenters would be administratively burdensome to provide and would likely lead to disputes – taking away resources they claim would be better allocated toward connecting more DER to their system.[187]

In light of the requests for more transparency, Xcel offers that they would be willing to provide a summary explanation for the cases where the final costs of a project vary by more than 25% from their most recent cost estimate[188]. They claim the biggest variables to "cost changes typically occur due to timing of installation (winter vs. summer), requested changes by the developer, changes to in-service dates, mobilization changes due to developer schedules or readiness and other factors that vary by project".

Cost Guides

[182] Page 12: Fresh Energy, Reply, 10/01/2021
[183] Page 6: All Energy Solar, Reply, 10/01/2021
[184] Page 12: Fresh Energy, Reply, 10/01/2021
[185] Page 7: All Energy Solar, Initial, 8/25/2021
[186] Page 36: Xcel, Reply, 10/01/2021
[187] Page 38: Xcel, Reply, 10/01/2021
[188] Page 38: Xcel, Reply, 10/01/2021

Fresh Energy also requests that Xcel and all rate-regulated utilities "develop and publish on their websites a cost guide for typical DER upgrades within 30 days of this Order, update it as needed, and notify the Commission in this docket whenever the guide has been updated." [189] It is their hope that this information can inform interconnection customers' decisions about siting, project sizing, and financing and that when combined with information gathered from Xcel's Hosting Capacity Analysis the DER customer decision making process will be significantly accelerated.[190]

Furthermore, Fresh Energy wants all rate-regulated utilities to publish an Accounting Treatment Guide for DER Interconnection Costs [191]. They want this guide to explain how the utilities "consider factors including depreciation, salvage value, and tax implications of contributions in aid of construction in costs assessed for interconnection." Staff confirms Xcel Energy provided the same Accounting Treatment for Costs of Distribution Upgrades document in Att. D of the Company's Reply as was initially provided on February 22, 2019 in the Company's MN DIP tariff implementation docket (E002/M-18-714) and again in a Formal Complaint docket last year.[192]

Xcel requests the Commission reject Fresh Energy's ask for a generalized cost guide akin to what the Company provides in Colorado[193]. They claim that the cost guide in Colorado is in absence to the more robust and more detailed indicative cost estimate provided in the MN DIP SIS study. Xcel believes that cost estimates are too variable in Minnesota and that a generalized cost guide would not be useful and may only lead to more disputes.

NES call for investigation

> NES requests a contested case for a Commission investigation of Xcel's Interconnection Practices under Minn. Stat. 216B.17 citing: 1) disputed material facts; 2) challenges with Xcel engineer retention; 3) ongoing, missed MN DIP timeframes.[194] NES acknowledges they may not participate as a party or intervenor given the legal costs, but believe state agencies should fully engage to determine what is going on with Xcel's interconnection process. Xcel Energy responds to NES's allegations and argues there is no basis for a separate investigation.[195]

Advanced Inverters

> AES highlights the importance of the Commission issuing its Notice as soon as possible when IEEE 1547-2018 certified equipment is readily available to begin use of the technology that can assist with capacity constraints in high DER penetration areas.[196] Xcel Energy is working

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[189] Page 13: Fresh Energy, Reply, 10/01/2021
[190] Page 13: Fresh Energy, Reply, 10/01/2021
[191] Page 13: Fresh Energy, Reply, 10/01/2021
[192] Att. D: Xcel Energy Reply (10/01/2021); Attachment A: Xcel Energy, Reply, 8/23/21 (Docket No. E002/C-21-126)
[193] Page 38: Xcel, Reply, 10/01/2021
[194] Pages 11-17: NES Initial (8/25/2021)
[195] Pages 31-35: Xcel Reply (10/01/2021)
[196] Page 9: AES Initial Comments

on an implementation plan for advanced inverters and will share it with stakeholders when it is complete (anticipated at the end of 2021).[197]

IV. Staff Analysis

Action by the Commission on the issues presented here is necessary to provide relief to interconnection customers and utility staff facing frustratingly long queues and interconnection timelines. Staff commends commenters who provided real world insight and data analysis of MN DIP implementation; as well as constructive solutions-based proposals to challenges. This approach and commitment are what has made the DGWG's efforts and Minnesota's interconnection update a model nationally.

As the Commission considers amendments to the MN DIP, staff notes the MN DIP is a generic, statewide interconnection standard that strives to be easily understandable and non-discriminatory, among other things.[198] To that end, staff encourages the Commission and parties to avoid adding provisions for a specific utility to the MN DIP, and rather use an approach like MN DIP 1.8.4 where a threshold triggers additional requirements or permissions (i.e. 40 applications per year means the utility most post a monthly queue on the Company's website.) Staff suggests such approach will allow the standards to better stand the test of time in balancing statewide consistency with accounting for different system requirements. Similarly, staff cautions against adding untested detail to the MN DIP and offers that companion guidance enabled by the MN DIP strikes the balance of transparency and oversight with maintaining a generic, statewide standard.

A. Interconnection Queue Management

Notably, developers and Xcel disagree on who pays for restudy when an ahead-in-queue project is withdrawn. The MN DIP does not expressly address restudy; rather, it states the Interconnection Customer is responsible for a study fee based on the utility's actual costs.[199] This is an important point to clarify. When faced with years of delay, developers argue they are willing to assume the risk and cost of restudy. However, when projects one-by-one run into distribution upgrades on a capacity constrained feeder and withdraws, the next-in-queue studied in parallel faces the initial study costs and potentially a restudy to reach the same conclusion. Where high risk of restudy exists, serial – and ideally group or cluster – study is preferable. That said, where restudy risk is low, extending parallel review could help improve review timeframes. The question for the Commission is what step in the process for the ahead-in-queue and/or queue conditions mitigates that risk. A complicating factor when high distribution upgrade costs or restudy risk exists is that the more parallel the study is the less accurate the cost estimate to the interconnection customer is. This can increase the risk of projects withdrawing at, or after, the step of signing the interconnection agreement. Xcel Energy, nor Minnesota, is unique in facing this interconnection challenge as DER penetration

[197] Page 30: Xcel Energy Initial
[198] Page 1: MN DIP Forward
[199] Page 2: MN DIP Att. 6 System Impact Study Agreement, Cl. 9-10

increases to the point of triggering high-cost distribution upgrades. There is no silver bullet, but, as Xcel and others note, well-designed cluster studies can help.

Interconnection queues and lengthy review timeframes are a serious issue. In addition to rolling out a mandatory cluster study pilot, staff recommends the Commission consider requiring Xcel to move the next-in-queue review trigger to earlier than a signed IA in the near term to test: 1) whether this results in faster review timeframes or wasted time and resources, and 2) whether interconnection customers are willing to pay study fees based on actual costs when restudy costs are included. Staff also suggests that parallel studies on feeders in unconstrained areas may be worth implementing to reduce the queue length. Capturing lessons learned and real-world experience is a crucial aspect of identifying interconnection best practices whether ultimately codified in the MN DIP or just encouraged. The Department recommends reporting for Xcel's current extended parallel review for up to 40 kW which could be adapted if the Commission considers other proposals in this area. From staff's perspective, a change to the MN DIP to address this issue is not needed at this time.

B. Cluster Studies

Parties agree cluster studies are part of the solution to congested queues. Parties do not agree with the details of Xcel Energy's proposed mandatory approach. While staff agrees a change to the MN DIP 1.8.3 is likely needed to support mandatory, rather than permissive, group studies, staff cautions against prematurely memorializing cluster study details in the MN DIP. The Commission could approve language allowing mandatory studies, allow Xcel to pilot the Company's proposed guidelines in the near term, and ask stakeholders and the Company to work toward addressing outstanding issues to improve the guidelines within a 180-day timeframe. Staff also notes that several parties emphasized *conditional support,* insisting that increased transparency regarding the costs and justifications of upgrades would be necessary for them to agree to a cluster study process. The Commission has heard the arguments on both sides regarding itemized costs and lack of cost transparency before in Formal Complaints and the DGWG. Parties are at an impasse that seems untenable and important to find a workable path forward on other proposals in this docket.

Staff recommend the Commission adopt a variance to MN DIP 1.8.3 to allow Xcel to pilot mandatory cluster studies (both DPS and TPS), require the Company to report on the pilot findings after 6 months, and engage with a working group by sharing early findings to improve the mandatory cluster study pilot such that the Company can incorporate workgroup recommendations in the 6 month compliance filing on the pilot. If the Commission takes this approach, you should consider whether you want to put any limitations on the mandatory cluster process the Company has proposed if it is operated as a pilot; namely, whether the Commission wants the Company to reconsider the DER TPL or small DER capacity reservation or also pilot more itemized cost estimates or cost guides. Staff believe the Commission could adopt the mandatory cluster study pilot and some of the queue management proposals discussed next to expand Xcel's tool kit to address frustration associated with long queues and timeframes. Any Minnesota electric utility, including Xcel, can proceed with voluntary group studies under existing MN DIP language.

Staff acknowledge Xcel's Dec. 17 letter with a MISO Affected System study provides detail that was not transparent prior in the MN DIP related to Affected Systems studies and the shared jurisdiction for DER interconnection applications that may impact the transmission system. Staff is unclear whether other utilities or stakeholders have been consulted or reviewed the MISO ASIS, how the ASIS impacts or fits with TDS cluster studies, and what sort of shared learning will occur between MISO, Xcel and the DGWG if and when Affected System studies are needed.

C. DER Technical Planning Limit

Staff commends Xcel Energy for staying implementation of the DER Technical Planning Limit after an objection was filed. Utilities make planning assumptions in design and operation of distribution grids to maintain safety and reliability, and the Commission typically only engages in review when a complaint alleges good utility practice or engineering judgment was not used. In recent Formal Complaints, rather than determining what the study assumption should be used the Commission has considered whether the practice was arbitrary or discriminatory and required the utility to make it public and address stakeholder feedback to ensure a sound assumption.[200] The Commission could apply that same standard in considering this issue. Staff agrees no change to the MN DIP is needed on this topic.

While staff suggests deferring to the Company's engineering judgment, Commission oversight extends beyond urging transparency and addressing issues raised in Formal Complaints. The Commission, utility, and stakeholders should consider how good utility practice changes over time to utilize grid modernization tools and equipment investments designed, in part, to improve grid operations and utility planning; including in prudency review of said investments. Broad "rules of thumb" like the TPL are conservative estimates necessary when the utility does not have visibility or awareness of the distribution grid (e.g. Xcel utilizing a 20% assumption for daytime minimum load in hosting capacity analysis until the Company was able to capture more accurate readings at the feeder level using SCADA investments). As ratepayer funds are spent on distribution grid modernization and upgrades, the expected benefit is better utilization of the grid to serve all customers whether via reliable electric service, DER interconnection, or participation in beneficial rates and programs. Minnesota, in many ways, has been on the forefront of this new frontier and benefits from the experience of distribution cooperatives, like Dakota Electric, and Xcel Energy with high DER penetrations and ongoing customer expectations for more. In addition to continuing discussions on these issues in the DGWG and utility-specific stakeholder groups, this is a topic ripe for ongoing consideration in Integrated Distribution Plans and cost recovery dockets.

As Xcel's January 11 letter demonstrates Xcel and Minnesota however are not alone in the challenges facing distribution utilities and grids with high volumes of applications and DER

[200] Xcel includes an information sheet on the TPL in Att. B to Xcel Reply (10/1/21)

penetration and we can learn from other utilities and states. Given the timing of this letter, staff notes other parties may have additional examples or detail to Xcel's helpful summary.

D. DER Reservation Cap

The Commission will want to consider whether statute allows for a reservation of utility hosting capacity for certain types of DER. Staff is aware some customers, sometimes with non-export applications, have been frustrated when attempting to install a DER to offset their load has led to distribution upgrades because, in essence, their load is already being "offset" by a DER in the area. Staff wonders if the TPL (or a version of it) could help with these instances if DER sited with load were allowed to exceed the TPL. Regardless, staff does not support modifications to the MN DIP with the level of specificity suggested by Xcel until there is more agreement at the DGWG, policy guidance from the legislature, or record development on the disputed issues.

E. Cost Sharing Proposals

Cost sharing proposals are another example of an important piece of the puzzle when a utility faces higher penetrations of DER which calls into question policy considerations around fairness and affordability.

Staff recognizes the Department's oversight role of the Solar*Rewards program and cautions proceeding with Xcel's proposal if the Department opposes it. Staff acknowledges this approach could help customers in communities, like Northfield, where hosting capacity is severely limited, but it comes at the cost to other customers who want to interconnect solar where hosting capacity exists (fewer incentive recipients). Xcel's cost sharing approach blurs cost causer pays principles by using funds from all ratepayers that have already been assigned to DER customers (via incentive payments) who may or may not trigger upgrades. Staff has some concern this proposal doubly benefits some DER customers, who both receive a Solar*Reward incentive and up to $15,000 for distribution upgrades, while later DER customers may not have access to either benefit even if their DER is at a location more beneficial to the grid. That said, staff does not oppose piloting Xcel's proposal, perhaps with a cap of $250,000, if the Department agreed. Staff takes no position on whether non-Solar*Rewards projects should be eligible but recognizes there may be efficiency using the Solar*Rewards program for implementation of this pilot.

Fresh Energy's proposal follows the cost causer pays principle with the flat fee administered to new DER customers and has the Department's support. The proposal is also more inclusive than Xcel's proposal as it is not limited to residential Solar*Rewards customers. The tradeoffs with this proposal are that it would be more administratively burdensome to Xcel and would effectively have DER customers in unconstrained areas, that would not require a distribution upgrade, subsidize the DER customers interconnecting in constrained areas.

Several parties were open to either or both of these cost-sharing proposals and expressed interest in expanding the scopes of the plans to make more DER projects eligible for cost-sharing - most notably, AES's proposal to expand Xcel's eligibility. However, many of the parties are open to different cost-share designs, emphasizing that they simply desire *a* cost-share design to be implemented. Staff seconds this opinion. Staff also notes that similar to the conditional support for cluster studies, several parties requested more cost-transparency (such as justified itemized costs) if a cost-sharing proposal were to be moved forward.

Staff recommends that Xcel work with the Department to determine if their cost-sharing proposal will work and, in the meantime, develop a cost-sharing proposal similar to Fresh Energy's proposal, but extend implementation in 4Q 2022. Staff does not think it is realistic to implement the Fresh Energy proposal within 60 days of the Commission's order given the program design, billing, and tracking details. A plan within 60 days of the order with implementation before the end of 2022 seems more realistic while recognizing the urgency some customers are experiencing and if adopted with the Xcel Solar*Rewards cost sharing pilot may provide a longer term solution.

F. Dispute Resolution Process

Staff does not support a change to the MN DIP at this time. Xcel is correct that CAO first inquires with a customer, whether an interconnection customer or not, if they attempted to resolve the issue directly with the utility which is the best practice and encouraged in MN DIP 5.3. Staff also agrees with Xcel, the Department, and Fresh Energy that an online Notice of Dispute form and expedited process for non-technical issues is worthwhile. That said, staff cautions the Commission not to make decision about QSP customer complaint definitions in this docket. Xcel Energy's proposal was filed in the QSP docket and has opposition as summarized in this docket. Xcel seems to see the primary purpose of spelling out the expedited process for non-technical issues is to clarify what counts as a QSP customer complaint.

Staff appreciates AES, MnSEIA, and Xcel Energy identifying ongoing opportunities to address disputes in stakeholder meetings and informal surveys. The Commission has encouraged this type of collaborative effort to identify and address interconnection issues since the DGWG began in 2017 – whether in the DGWG or in Xcel's many other stakeholder forums.

Lastly, staff supports Dakota Electric's proposal for the DGWG, or if more appropriate utility-specific stakeholder groups, to create independent, unbiased technical review process and a queue or policy review process. Staff sees this as an Independent Engineer 2.0 process, something NES supports, where some of the challenges that plagued that early effort can be addressed while recognizing the ongoing need for independent, or trusted, technical expertise to inform the issues that are raised in the details of this proceeding and in the increasing number of Formal Complaints the Commission has saw in the past year.

V. Decision Options

A. Interconnection Queue Management

1. Require Xcel to phase out the "on-hold" practice of staying project timeframes to perform serial review of interconnection applications.
    a. Immediately *(Nokomis)* **(OR)**
    b. For all customer-sited DER applications from "on-hold" within three months *(AES)* **(OR)**
    c. Over the course of a year with quarterly compliance reporting *(IREC, Fresh Energy)*

2. Require Xcel to expand its parallel processing to all Fast-Track projects within 30 days of this Order. *(Fresh Energy, Nokomis)*
    a. Applied only to areas where there are no known capacity constraints *(Department, IREC)*

3. Require Xcel to move the trigger to begin reviewing the next-in-queue project when the ahead-in-queue has:
    a. Completed a System Impact Study *(Fresh Energy, MnSEIA, Pivot Energy)* (**AND**)
        i. until queue crisis is managed or until mandatory cluster studies is implemented *(IREC)* (**OR**)
    b. Begun the Facilities Study *(MnSEIA and Pivot Energy Alternative)* (**OR**)

4. Reduce the timeframe the Interconnection Customer has to sign an Interconnection Agreement from 30 to 15 Business Days. *(Xcel, Pivot Energy) (Staff Note: requires a change or variance to MN DIP 5.1 for non-Simplified applications and MN DIP 2.3.1 for Simplified.)*

5. Require Xcel to increase tracking and reporting on the parallel processing of 40kW and under projects to include: *(Department)*
    a. Number of projects <40Kw that failed Initial Review Screens, Supplemental Screens, and required Upgrades by
        i. Per quarter in the year before parallel screening was implemented;
        ii. Per quarter after parallel screening was implemented;
    b. Identify/tag applications screened in parallel;
    c. Additional analysis on the potential impact to interconnection costs of switching to parallel processing

B. Cluster Studies

6. Approve Xcel's MN DIP additions to 1.8.3 addressing mandatory cluster studies. *(Xcel)* (**AND?**)

    a. Approve Xcel's proposed MN DIP 1.9 addressing a DER Technical Planning Limit and Open DER Capacity Limit *(Xcel) (accomplishes Decision Option 22)* (**OR)**

7. Deny Xcel's MN DIP revision proposal as it relates to mandatory cluster studies. *(IREC, MnSEIA, Fresh Energy, NES, ILSR, the Department)* (**OR**)

8. Grant Xcel Energy a variance to MN DIP 1.8.3 to pilot mandatory cluster studies for areas with three or more > 40 kW applications that cannot be reviewed in parallel. *(Staff)* (**AND, OR)**

9. Create a Working Group to discuss key topics of a cluster study convened by
   a. The Commission *(IREC)* **(OR)**
   b. Xcel *(Department)*

10. The Working Group would be conducted over a period of
    a. 60 day period *(Department)* **(OR)**
    b. 90-day period *(Department, MnSEIA, IREC)*
    c. 180-day period *(Staff)*

11. The Working Group would discuss and file a report with an issues matrix detailing all resolved and unresolved issues, a description of party positions and recommended decision options along with any references to record documentation on the following topics: *(Department modified by Staff):*

    a. Circumstance when utility is required to perform group study *(IREC)* **(AND, OR)**
    b. Rules for how mandatory groups are formed (notice, timing, etc.) *(IREC, Fresh Energy, Department*) **(AND, OR)**
    c. Description of the studies to be performed in a group study, including identification of when individual assessments may be required *(IREC)* **(AND, OR)**
    d. Defined timelines for all utility and customer steps of the process, and definition of what happens if timelines are not met *(IREC, Department, MnSEIA)* **(AND, OR)**
    e. Timelines for group studies should be in alignment with those used by other states. *(IREC*) **(AND, OR)**
    f. Description of what happens when projects drop out after the group study process has started. This includes defined opportunities for projects to drop out, and deposits or other penalties to deter dropouts later in the process. *(Department)* **(AND, OR)**
    g. Group Retention Strategies *(Fresh Energy)* **(AND, OR)**
    h. Provisions for sharing of both study and upgrade costs (*IREC, Fresh Energy, Department)* **(AND, OR)**
    i. Rules for how existing applications may be transitioned into the group study process and how the process may change after the initial queue backlogged is cleared. *(Fresh Energy)* **(AND, OR)**
    j. Topics identified by findings from Xcel's mandatory cluster study pilot *(Staff)* **(AND)**

12. Direct Xcel to provide the following reporting on any voluntary pilot Group Study processes it implements: *(Fresh Energy, Xcel)*
    a. A compliance filing six months after the Order in this matter describing the participating applications, relevant feeder and substation characteristics, the time in which each phase of the study was completed, any group retention measures (deposits or penalties), the general cost allocation process used, and any disputes that arose.
    b. A presentation at the next Solar*Rewards Community stakeholder meeting that follows submission of this report, to be given by Xcel with input from participating applicants about the process and lessons learned.

C. DER Technical Planning Limit

13. Approve Xcel's authority to implement the DER Technical Planning Limit. *(Xcel)* (**OR**)

14. Deny the implementation of Xcel's DER Technical Planning Limit. *(IREC, MnSEIA, Fresh Energy, AES, NES, the Department, Nokomis, and SUN)* (**AND**)

15. Direct the Executive Secretary to procure an independent third party to evaluate if the DER TPL is the best solution for a future where demand for DER is going to increase. *(AES)*

16. Require Xcel to discuss any specific issues that arise as a result of reduced DML on feeders with high DER capacity, or specific issues related to DER and operational flexibility, in its quarterly compliance filings in this docket. *(Fresh Energy)*

17. Establish a DGWG subgroup to explore the risks currently faced and the impacts and effectiveness of the proposed TPL *(Fresh Energy)*

18. Require Xcel to acquire the staffing and technical capabilities to conduct studies, even in complex cases, within the required timelines. *(ILSR, MnSEIA, IREC)*

19. Require Xcel to provide, within 60 days of the date of the order, a full technical assessment of each of the capacity constrained locations that identifies the technical issues, details possible upgrades or other remedies for mitigating the constraint and estimated costs and timelines for implementing those solutions *(Department, Fresh Energy, IREC, ILSR)*
    a. Direct Executive Secretary to issue a notice of comment period and set a comment schedule after Xcel's Known Capacity Constraint report is filed, to allow stakeholders to comment on the completeness of the assessment, the merits of various solutions Xcel presented, and to offer alternative solutions. *(Fresh Energy)*

20. Direct all rate-regulated utilities seeking to make a substantial interconnection process change – even if it does not explicitly require a MN DIP amendment – to file a notice in this docket explaining the issue, citing concrete examples, providing workpapers or background documentation if relevant, and explaining in detail their proposed change. The notice must be submitted at least 30 days before the utility's proposed implementation date. If no party comments or submits a notice of intent to comment within 30 days, the change will be accepted, otherwise the Commission will open a notice of Comment Period to consider the proposed change. *(Fresh Energy)*

21. The Commission will evaluate whether utilities with known capacity constraints that delay or limit interconnection could make proactive investments or changes to encourage DER while protecting ratepayers in rate-regulated utilities' biennial Integrated Distribution Plans or, if applicable, Hosting Capacity Analysis reports. *(Staff modification of Dakota Electric, AES, NES, IREC, Fresh Energy, MnSEIA)*

D. Small DER Capacity Reservation

22. Approve Xcel's MN DIP 1.9.1 edit, allowing 25% of the DER Technical Planning Limit to be reserved for Small DER (net-metered DER systems 40kW or less that comply with the 120% rule). *(Xcel)* (**OR**)

23. Deny Xcel's MN DIP 1.9.1 edit. *(Department, IREC, AES, Nokomis, MnSEIA, NES, the City, ILSR)* (**AND**)
    a. Should Xcel opt to bring forward another capacity reservation proposal in the future: *(Fresh Energy)*
        i. The amount of the capacity reservation should be based on expected DER growth and other anticipated changes in electrical conditions.
        ii. The amount of the capacity reservation should be adjusted to the characteristics of each substation and feeder.
        iii. Xcel will include supporting documentation to demonstrate why the capacity reservation is needed and why each proposed reservation amount is justified

24. Direct the Executive Secretary to procure an independent third party to evaluate if the Small DER Capacity Reservation is warranted. *(AES)*

E. Cost Sharing

25. Approve Xcel's cost-sharing proposal by accepting the Solar*Rewards tariff edits on sheet 9-49. *(Xcel, MnSEIA):*

    a. Approve an expanded version of Xcel's cost sharing proposal as proposed by All Energy Solar. *(AES proposed tariff modification)*
    b. Approve Xcel's cost sharing proposal but include non-Solar*Rewards customers that are 40kW or smaller and meet the 120% rule. (*MnSEIA, NES, Fresh Energy - requires a tariff modification by Xcel)*
    c. Cap the pilot at $250,000 *(Staff)*

26. Approve the cost-sharing proposal for Xcel customers with 40 kW or less DER created by Fresh Energy, IREC, and TruNorth to be implemented within 60 days of this Order. *(Fresh Energy, IREC, AES)* (**OR**)

    a. Approve an altered version of Fresh Energy's cost-sharing proposal that excludes the eligible customers under Xcel's cost-sharing proposal*. (MnSEIA) (must include Decision Option 25)*

27. Approve the cost-sharing proposal for Xcel customers with 40 kW or less DER created by Fresh Energy, IREC, and TruNorth with a plan by the Company to implement by the end of 2022 within 60 days of this Order. *(Staff alternative modifying Decision Option 26)*

28. Require Xcel to take into account depreciated value of existing equipment being replaced or upgraded as part of its estimate of the flat fee, and track and report all upgrades and associated costs for its Solar*Rewards program. *(Department)*

29. Require Xcel to have the Facilities Study include itemized costs for distribution and network upgrades and interconnection facilities, as well as an indication if a smaller system size would avoid major upgrades. To be implemented within 60 days of the order. *(Fresh Energy AES, IREC, Department)*

30. Require Xcel to file a comprehensive report on the cost-sharing program one year from the implementation date, which will inform the Commission's decision about whether to continue or modify the program. *(Fresh Energy)*

F. Dispute Resolution Process

31. Approve Xcel's MN DIP 5.3.8 edits. *(Xcel)*
    a. Require Xcel to provide reports on the number of complaints received, types of complaints, time to resolve the complaint, and if the underlying issue was addressed. (AES)
    b. Customers with a complaint about a missed timeline may file a complaint with the CAO at the same time they complete Xcel's Notice of Dispute Form. *(Fresh Energy)*

32. Approve Xcel's proposal to clarify an expedited, non-technical dispute resolution process. *(Xcel) (This issue was also raised in Docket No. E002/M-12-383)*

33. Request the DGWG to propose an independent, unbiased technical review process and a queue or policy review process with the goal of reducing appeals to the Commission. *(Dakota Electric)*

34. Direct the Executive Secretary and Xcel to provide information on the updated dispute process on relevant webpages, including a link to the Notice of Dispute Form and a statement that customers may file a complaint with the CAO after filing a Notice of Dispute Form with Xcel. *(Fresh Energy)*

35. For complaints regarding issues other than compliance with MNDIP timelines, customers can file a complaint with the CAO after the corresponding resolution period (10 business days for non-technical, 20 business days for technical disputes) if they are not satisfied with the response or resolution received. *(Fresh Energy)*

36. In future quarterly MN DIP compliance filings to the Commission, Xcel should provide: *(Fresh Energy)*
    a. The number of nontechnical and technical dispute notices received that quarter
    b. The number of nontechnical and technical disputes resolved that quarter
    c. A breakdown of all dispute notices received that quarter by issue area
    d. A discussion of work planned, ongoing, or recently completed to address issues highlighted by nontechnical and technical customer disputes
    e. Any other relevant information

G. Miscellaneous

37. Require Xcel to provide a detailed report of the costs incurred and technical rationale for each upgrade should the Company seek cost recovery for distribution upgrades from Solar*Rewards customers or request to charge a fee to certain DER customers to cover interconnection upgrades. *(Fresh Energy AES, IREC, Department)*

    a. Direct the Executive Secretary to monitor itemized costs to evaluate appropriateness and intervene if necessary. *(AES)*

38. Require Xcel, upon request, to provide additional detail regarding cost changes over 25 percent relative to the most recent cost estimate. *(Xcel)*

39. Require all rate-regulated utilities to develop and publish on their websites a cost guide for typical DER upgrades within 30 days of this Order, update it as needed, and notify the Commission in this docket whenever the guide has been updated. *(Fresh Energy)*

40. Require all rate-regulated utilities to publish Accounting Treatment Guide for DER Interconnection Costs within 30 days of the order. *(Fresh Energy)*

41. Convene an accountability subgroup to provide recommendations to the Commission on utility accountability for MN DIP compliance. *(IREC)*

VI. Attachment A

Xcel Energy proposed additions to

MN DIP 1.8.3, proposed new MN DIP 1.9, and redline revisions to MN DIP 5.3.8

A. Xcel Energy proposes adding the following MN DIP provisions to MN DIP 1.8.3 to address mandatory cluster studies:

1.8.3.1 (Applicable to Xcel Energy only) Notwithstanding the provisions of 1.8.3 above, an Interconnection Application will be subject to a mandatory cluster study as set forth in MN DIP 1.9, or as set forth in 1.8.3.2 or 1.8.3.3 below.

1.8.3.2 (Applicable to Xcel Energy only) Interconnection Applications not subject to MN DIP 1.9, shall be subject to a mandatory cluster study (called Distribution Group Study), provided that no Interconnection Application can be subject to a mandatory cluster study if the Interconnection Application is for a project that is less than or equal to 40 kW, when all of the following conditions are met:

1.8.3.2.1 When there are three or more Interconnection Applications in sequential order in the same queue;

1.8.3.2.2 When the Area EPS Operator determines that the Upgrades needed for interconnection are expected to be limited to the distribution system (e.g., feeder upgrades, Voltage Supervisory Reclosing (VSR) or other protection modifications), and to not include a need for a substation transformer upgrade or a new feeder.

1.8.3.3 (Applicable to Xcel Energy only) The Distribution Group Study process may need to have different processes than what would ordinarily be part of the MN DIP process, and therefore will be handled on an individual case basis as designed by the Area EPS Operator, and not subject to MN DIP timelines and processes prior to the signing and funding of the MN DIA.

B. Xcel Energy proposes a new MN DIP 1.9 to address DER Technical Planning Limit and mandatory cluster studies:

MN DIP 1.9 (Applicable to Xcel Energy only)
<u>Mandatory Cluster Study When DER Technical Planning Limit or</u> Open DER Capacity Limit<u> is Exceeded</u>

At any time after an Interconnection Application has been deemed complete, but before a System Impact Study has begun, the Area EPS Operator may apply a screen for the **DER Technical Planning Limit.**

1.9.1 The overall **DER Technical Planning Limit** may be defined by the Area EPS Operator (e.g., the aggregate nameplate capacity of all DER installed or ahead in queue plus the project being studied may not be more than Daytime Minimum Load (DML) plus 80% of the equipment rating of either the substation transformer or feeder). The first 75% of the **DER Technical Planning Limit** for the feeder and/or substation DER capacity is available for all DER, including Community Solar Gardens, **Small DER** (as defined below), and all other DER on a first come first serve basis. This first 75% is called the **Open DER Capacity Limit**.

The remaining 25% of the **DER Technical Planning Limit** for the feeder and/or substation is exclusively reserved for net-metered DER systems 40 kW or less that comply with the 120% rule (**Small DER**). The 120% rule shall be calculated consistent with how the Area EPS Operator applies the similar rule in its Solar*Rewards Community program. To clarify, this has the following stepped approach:

- First, the DER Technical Limit is applied to system (feeder/substation);
- Then, 25 percent of the remaining capacity would be "reserved" for Small DER;
- The remaining 75 percent of capacity would be available for all system sizes on a first come, first served basis, however, Small DER will be counted towards this category only after the 25 percent Small DER
- Capacity Reservation is reached.

1.9.2 If a **non-Small DER** Interconnection Application exceeds the **Open DER Capacity Limit**, or if a **Small DER** Interconnection Agreement exceeds the **DER Technical Planning Limit**, then the Interconnection Application will be removed from the queue for the feeder originally assigned to it and be put into a different queue that will apply to those Interconnection Applications that exceed the **Open DER Capacity Limit** and/or **DER Technical Planning Limit.** The Interconnection Applications in this type of queue will be subject to **Transmission and Distribution Studies (TDS)** and would be studied in the relevant geographic area pertaining to the address of the proposed DER in the Interconnection Application. The type of queue these are placed in is called a **DER TDS Queue**.

1.9.3 The Area EPS Operator may have a number of **DER TDS Queues** in different geographic areas based upon use of its judgment as to what Interconnection Applications should be part of that same **DER TDS Queue** for purposes of studying new feeder(s) and/or new substation(s) and other transmission facility upgrades in order to allow DER interconnections.

1.9.4 If there are two or more Interconnection Applications that exceed the Open DER Capacity Limit in any specific **DER TDS Queue** then each will be subject to a mandatory cluster study that will be triggered about once a year, but in no event not earlier than the completion of all other cluster or serial studies in that particular **DER TDS Queue**. If there is just one Interconnection Application that has exceeded the Open DER Capacity Limit in any specific **DER TDS Queue** and after six months no other such Interconnection Application has been added to that **DER TDS Queue**, then it may be studied not as part of a cluster, but in no event earlier than the completion of all other cluster or serial studies in that particular **DER TDS Queue**. **Small DER** projects are not subject to the mandatory cluster study set forth in this MN DIP 1.9. The completion of a cluster or serial study for these purposes shall be marked by each Interconnection Application ahead in the **DER TDS Queue** either being cancelled or being the subject of a signed and funded MN DIA.

1.9.5 If any Interconnection Customer refuses to participate in this type of cluster study on the **DER TDS Queue**, or does not timely sign and fund a statement of work for this type of study, the associated Interconnection Application shall be cancelled by the Area EPS Operator.

1.9.6 The cluster study process to be followed for a **DER TDS Queue** may need to have different processes than what would ordinarily be part of the MN DIP process, and therefore will be handled on an individual case basis as designed by the Area EPS Operator, and not subject to MN DIP timelines and processes prior to the signing and funding of the MN DIA.

1.9.7 The Area EPS Operator may make adjustments to various study guidelines applicable to the **DER TDS Queue**, focused on improving the process, and based on feedback from stakeholders. A study transition plan will be developed to transition from studying projects serially to cluster studies.

1.9.8 Adding new substation transformer banks expressly for a **DER TDS Queue** is not contemplated as part of the initial implementation of this process.

C. Xcel Energy proposes the following redline changes to MN DIP 5.3.8:

5.3.8 After first complying with sections 5.3.1 through 5.3.7, ~~At any time,~~ either Party may file a complaint before the Commission pursuant to Minn. Stat. §216B.164, if applicable, and Commission rules outlined in Minn. Rules Ch. 7829. However, in no event may any complaint or dispute for any interconnection issue or alleged violation of MN DIP be filed with the Commission against the Area EPS Operator more than one year after the act or omission that forms a basis of the complaint or dispute.