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Minneapolis, MN 55401

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December 20, 2021

—Via Electronic Filing—

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

RE: IN THE MATTER OF A FORMAL COMPLAINT AND PETITION FOR RELIEF BY NOKOMIS ENERGY LLC AND OLE SOLAR LLC AGAINST NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY
DOCKET NO. E002/C-21-786

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits these Comments pursuant to the Commission's November 18, 2021 Notice of Comment Period regarding the above Nokomis Energy LLC and Ole Solar LLC (collectively, Nokomis) Formal Complaint and Petition for Relief.

Certain information in this filing has been marked as Not Public Protected Data. Some of this is information that Nokomis may consider to be its Not Public Protected Data. Other information has been designated as Not Public Protected Data of Xcel Energy because this data is classified as trade secret pursuant to Minn. Stat. §13.37, subd. 1(b). This information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Brandon Stamp at Brandon.J.Stamp@xcelenergy.com or (612)337-2076 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES DENNISTON
ASSISTANT GENERAL COUNSEL

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF A FORMAL COMPLAINT AND PETITION FOR RELIEF BY NOKOMIS ENERGY LLC AND OLE SOLAR LLC AGAINST NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

DOCKET NO. E002/C-21-786

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Comments pursuant to the Commission's November 18, 2021 NOTICE OF COMMENT PERIOD regarding the above Nokomis Energy LLC and Ole Solar LLC (collectively, Nokomis) Formal Complaint and Petition for Relief.

The Notice specified four topics for comment:

- Does the Commission have jurisdiction over the subject matter of the Complaint?
- Are there reasonable grounds for the Commission to investigate these allegations?
- Is it in the public interest for the Commission to investigate these allegations upon its own motion?
- If the Commission chooses to investigate the Complaint, what procedures should be used to do so?

The Company agrees that the Commission does have jurisdiction over the subject matter of the Complaint. We do not believe, however, that there are any reasonable grounds to further consider the Complaint nor is it in the public interest for the Commission to further investigate the MN DIP process-related issues as specifically raised in the Complaint. As explained below, we have complied with applicable laws and regulations and have used Good Utility Practice and proper engineering judgment on how to process interconnection applications under Minnesota's Distributed Energy Resource Interconnection Process (MN DIP). Instead, we believe the MN DIP process – and technical-related issues – should be more broadly addressed in other proceedings where the Commission is already considering those issues rather than in one-off disputes that are similar in nature to other projects also located in congested queues. There are fundamental issues with Minnesota's distributed energy framework that have manifested in this and other complaints. We strongly believe these issues need to be addressed, but that is best handled in other more broadly-applicable dockets.

The balance of these comments discusses the merits of the Nokomis Complaint, provides context for the Complaint, including the underlying circumstances that led to it, and discusses how other utilities and states have constructively addressed similar distributed generation resources (DER) congestion and queue-related issues raised in the Complaint and that the Commission is examining in Docket No. E999/CI-16-521 (16-521 Docket). We note that we also include the following Attachments with these Comments:

- Attachment A: Summary of experiences of Duke Energy in the Carolinas, and the states of Oregon and New York;

- Attachment B: Overview of MN DIP timelines;

- Attachment C: Chronology of filings in Docket 16-521 addressing multiple applications in the same queue under MN DIP;

- Attachment D: Excerpts from NREL article, "*Updated Small Interconnection Procedures for New Market Conditions,*" published December 2012; and,

- Attachment E: Public/Non-Public Redacted Supplemental Review results for Ole Solar application.

Finally, the Company notes that there could be an issue with Nokomis acting as a public utility, under Minn. Stat. § 216B.02, Subd. 4, within the Company's exclusive service territory given its claims that a Nokomis-owned solar system will serve our retail customer's electrical needs.

COMMENTS

The Nokomis Complaint reflects symptoms of DER congestion in certain parts of our distribution grid due to high Community Solar Garden (CSG) penetration that is reaching the capacity limits of the distribution system. We have attempted to resolve these overarching issues at the legislature as well as through discussions with stakeholders, however modification of the MN DIP interconnection rules will also be necessary. In responding to the Complaint in these Comments, we not only show how we have properly complied with MN DIP in processing applications, but we also provide background intended to inform the Commission on the actions we believe are necessary to solve the queue congestion issues. We are not asking that the Commission take action on these issues in this docket; rather, we believe they provide context for this dispute and are intended to inform the Commission of certain implications of the current MN DIP and CSG program design.

There are physical limits on how much DER can be accommodated at any given point on the distribution grid. And even in situations where it is physically possible to expand the system to allow more DER, doing so often requires more complex engineering analysis for applications and a greater investment by the customer. Such investments can include building new feeders, new substation bays, or entire new substations. Connecting CSG's on the distribution continues to increase in technical complexity as the level of DER penetration increases and as the interconnection queue gets more congested. Today, however, CSGs are clustered on a limited number of feeders (approximately 15 percent of all Company feeders), saturating them to capacity limits. This drives up the cost, complexity, and timing to interconnect additional CSGs and other DER to those feeders. This can also leave a customer-sited solar project with a frustrating wait for an answer on its application for interconnection, as has occurred here.

This situation is compounded when we continue to receive interconnection applications for the already congested feeders, which results in increasingly long interconnection queues. Each project in each queue will have a unique impact on the system and must be studied based on the system conditions that exist at the time of study and must consider modifications needed to accommodate those ahead in queue. Moreover, because of the saturation of DER in certain areas, as explained in our December 17, 2021 filing in the 16-521 Docket, the Midcontinent Independent System Operator (MISO) has now established a process to review DER interconnection applications that may impact the transmission network. When required, the MISO studies will add to the cost and timeline for processing DER interconnection applications on feeders associated with affected substations.

We are not the only utility or state to experience issues like these. Below, we discuss how Duke Carolinas, Oregon, and New York have addressed DER congestion and long queues. We also discuss a Proposed Decision from an Administrative Law Judge (ALJ) in California recommending the state's utilities commission significantly lower rates paid for DER generation. We believe that this information provides helpful context and perspective on possible actions that the Company and Commission may need to take. These states and utilities changed their processes and practices to recognize that continuing to operate as they had been will not resolve problems like long queues, and will not facilitate interconnection of DER at the levels contemplated in current public policies.

To that end, the Company has already proposed changes, currently pending in the 16-521 Docket to address underlying causal factors to queue wait times. The proposed MN DIP changes are foundational and necessary to address problems in the distribution queue. But, to truly resolve the issues related to DER that we have seen increasing in recent years, we also believe there is need to reduce the CSG subscriber Bill Credit rate, which is the primary underlying cause of DER congestion and long queue lengths. The high Bill Credit rate also causes upward pressure on customer bills – particularly low-income and residential customer bills – disproportionate to the amount of energy generated by CSG resources.

To be clear, we provide this information only as context for the deeper issues. While the issues identified in the Complaint are directly tied to other MN DIP-related matters currently pending with the Commission in the 16-521 Docket, we are not asking the Commission to address them here. Nor are we asking for Commission to address the Bill Credit rate in the current docket. Instead, we are contemplating a filing in a different, and more broadly-applicable, docket to request Commission action. We also continue to engage with stakeholders as well as pursue legislative action to try to address this issue but are uncertain if these efforts will be successful.

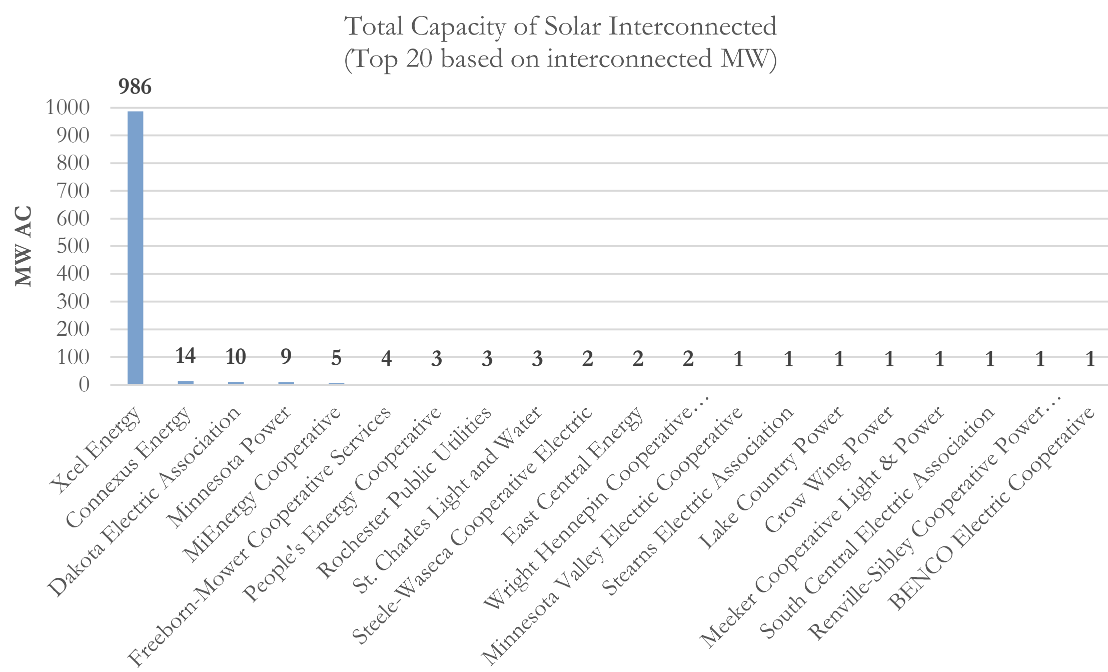
The Company has done nothing wrong with respect to the Nokomis application at issue in the Complaint. Further, the serial review process required by MN DIP and the Company's practices in implementing the MN DIP are not the sole cause of the problems that Nokomis and other solar developers are experiencing. Instead, the primary root cause for the saturated feeders, large number of applications in queue, and long wait times for study are in the CSG program structure itself and are the unintended consequences of many combined factors, including the unlimited aspect of the CSG program and the lucrative Bill Credit rate. As we discuss in these comments, we believe the Commission should dismiss the Nokomis Complaint and include the factual circumstances from this matter as it more holistically considers changes to MN DIP in the 16-521 Docket.

I. RAPID EXPANSION OF DER

Xcel Energy fully supports the development of DER and has nearly 1 GW of DER on our Minnesota system. As we transition away from coal and toward a low-carbon system that includes significant additional renewable resources, we need to consider all available opportunities to add clean energy. That includes both DER and significant amounts of utility-scale solar and other forms of clean renewable energy.

Based on data made available by Staff, [1] we have produced Figure 1 below which shows the total MW of solar interconnections for 20 utilities as of December 31, 2020, with similar scaling for each:

Figure 1



However, there are problems with the current structure of the state's CSG program, which overcompensates developers and incentivizes them to focus on interconnecting to a very small number of feeders. This leads to an environment where developers may bring issues to the Commission when they cannot make even the highly-compensated solar rates pencil out, or when the high concentration of interconnected projects and queued applications result in long timeframes to interconnect, even when the Company meets all milestones for processing interconnection applications.

The problems that are the subject of developers' complaints are in large measure unintended consequences of the MN DIP combined with the rapid expansion of DER in constrained areas, rather than the internal processes of Xcel Energy in processing interconnection applications. Developers may knowingly join a long queue and then be frustrated about the wait time due to the increasingly unworkable system and MN DIP process. In the case of the Nokomis Complaint, even an on-site DER application has been negatively impacted by the CSGs already interconnected or ahead in queue.

A. The High Bill Credits for CSG Subscribers Are a Root Cause of the Problems Being Brought to the Commission

While solar energy is an important part of the Company's clean energy strategy, energy from CSGs comes at a high cost for our customers compared to other solar resources. All Xcel Energy customers in Minnesota bear the cost for the expensive solar energy from CSGs. Moreover, residential and low-income customers disproportionately subsidize commercial and industrial customers, who are the primary subscribers to most of the CSGs and currently receive over 80 percent of the Bill Credits from CSGs.

The Company is required to purchase all of the energy CSGs produce at the pre-determined Bill Credit rate, which is more than double the cost for solar energy that is competitively bid at a market rate.[2] The lucrative Bill Credit rate has attracted a high volume of applications and our CSG program remains the largest CSG program in the nation. According to the Wood Mackenzie/SEIA US Solar Market Insight Q4 2021 report and associated data, Minnesota hosts 26 percent of the nation's installed community solar, outpacing all other states. Today, we have over 820 MW of interconnected CSGs, with over 450 MW in queue awaiting interconnection.

By the end of 2021, the Company will have paid out nearly half a billion dollars in Bill Credits to CSG subscribers in Minnesota. Over the next twenty to twenty-five years, the overall cost of this program in Bill Credits is expected to grow far above $2 billion. All of these costs flow through the fuel clause, and the vast majority are paid for by Minnesota retail customers as an additional cost included in their retail electric bills. Minnesota customers bear the cost of the program, in that all Bill Credit costs

[2] Comparison based on Xcel Energy's June 25, 2021 Reply Comments (at Appendix A p.26) in Docket No. E002/RP-19-368.

above MISO's LMP market are recovered from Minnesota customers. Other fuel costs are assigned to each jurisdiction based on the ratio of that jurisdiction's sales levels. For CSG Bill Credits, the costs at LMP market value are assigned to each jurisdiction based on sales ratios, and all Bill Credit costs above that are recovered from Minnesota customers. In 2020, Minnesota customers paid $146 million for the CSG program, including $130 million in costs above the MISO LMP market price. In 2021, the energy produced by CSGs accounts for about 3.5 percent of all energy produced for Xcel Energy in Minnesota, but the CSG Bill Credits account for about 20 percent of the overall cost of the fuel clause to our customers.

As a general matter, the Company uses competitive solicitations for additions of generation resources to create cost efficiencies that help keep customer bills low. Historically, the only exception to this related to certain small qualifying facilities, which have the right, under the Public Utility Regulatory Policies Act of 1978 (PURPA) to have a utility purchase the power they produce at the utility's "avoided cost," or other rate such as our A50 rate code for projects under 40 kW, or the cost the utility would have incurred to produce the power itself or contract from another source. Unlike these traditional approaches, which are designed to keep utility generation costs low, CSGs are expensive resources that would not have been selected through any competitive process and are pushing customer bills up in Minnesota. The CSG "Value of Solar" or "VOS" rates are in the range of about 2 to 2.5 times solar PPA rates, and the CSG "Applicable Retail Rate" or "ARR" Bill Credit Rate is even higher than this.[3] Because these rates are well above the market rate, developers from across the country have flocked to Minnesota to build and operate CSGs. With a half billion dollars in bill credits paid to this point, guardrails are needed to protect our customers from further financial burden that will persist and compound for at least 25 years if left unaddressed. These cumulative costs have the potential to harm all customers and increase their energy burden, while also impacting our ability to be competitive and attract new business and load to our service territory.

The growth for the Company's DER solar generation is largely driven by CSGs, which account for roughly 80 percent of DER solar generation on the Company's system. CSG installations have been rapidly increasing since 2015, when our Solar*Rewards Community program was launched. The size of the CSG program is far larger than we expected when the program was first proposed in legislation in 2013. At that time, there were only two distributed solar projects in Minnesota that were 1 MW or larger, and each project was considered significant enough to make news headlines. Today, new applications continue to come into the CSG program,

[3] Comparison based on Xcel Energy's June 25, 2021 Reply Comments (at Appendix A p.26) in Docket No. E002/RP-19-368.

fostering additional growth and increasing Bill Credit payouts. Currently, there is no limit in law or regulation on the size of the Company's CSG program.

Nokomis is a significant beneficiary of the high Bill Credits. Its web page notes that large industrial customers can save $564,000 on their energy costs by having a CSG subscription with them.[4] This is paid for with Bill Credits net of any costs charged by Nokomis. Also, Nokomis has disclosed that since 2017, it has developed 250 acres of CSGs in Minnesota.[5] If we assume that there are about 7 acres per 1 MW CSG,[6] then this indicates that Nokomis has already developed about 35 MW of CSGs in Minnesota.

The root cause of the high expense for the Bill Credits is the high subsidies built into the $/kWh rate paid by the Company for the energy produced by the CSGs. The costs of the Bill Credits will continue to grow as a result of the 25-year contract length for each CSG. Also, the $/kWh rate will also likely continue to grow under the two current Bill Credit methodologies which we describe below.

- *Applicable Retail Rate with REC Adder (ARR)*

The ARR methodology applies to almost all CSGs that were placed into service before 2021. Under the ARR, the rate changes annually, aligns with retail customers' overall cost for energy (not just generation), varies depending on customer class, and also includes an "adder" for the Company's acquisition of Renewable Energy Credits (RECs) so that the Company can claim credit for all renewable attributes from the solar energy produced. The current ARR generally ranges from $0.12770 to $0.158670 / kWh (or $127.7 to $158.67 /MWh). Because the ARR includes the overall cost of energy in retail bills, as the CSG program issues more Bill Credits, they are reflected in the fuel clause, a component of retail bills. This in turn will cause a higher ARR rate next year, which in turn will cause even higher Bill Credit rates the following years. Our April 1, 2016 comments in the CSG docket noted the "snowball effect" of the ARR and the upward pressure this would cause on the fuel clause.

- *Value of Solar (VOS)*

The other methodology for Bill Credits is the VOS, which applies to all CSG applications submitted after January 1, 2017. These applications started coming into commercial operation in 2019. The VOS rate applies a 25-year table of rates that show escalation of the VOS rate for each year the CSG is in operation. A new VOS table is added annually, detailing the bill credit rates in effect for CSGs whose applications are deemed complete during that CSG vintage year. The rates in the specific VOS tables change between years for various reasons, but all show escalation of rates. The 2017 VOS Vintage table has first year rates of $0.1033 /kWh (or $103.3 /MWh) but are set to annually increase so that by the last year of the 25-year contract the rate will be $0.1791 /kWh (or $179.1 /MWh). Accordingly, the bill credit rates will increase over the next 25 years for CSGs in service today. Additionally, as more CSGs come into operation under the VOS Bill Credit rate, there will be annual escalation in the Bill Credits paid and additional costs included in the fuel clause that in turn will further increase the bills of retail customers. There has also been additional compensation to the VOS, for the tables applicable to CSG applications submitted in 2019 through 2022, of an additional $0.015 / kWh (or $15/ MWh) to be paid for each residential subscription for the 25-year term of each CSG.

The vast majority of the CSG capacity subscribed and Bill Credits go to commercial and industrial customers – residential subscribers receive only about 17 percent of the Bill Credits, while about 83 percent of the Bill Credits go to commercial and industrial customers.[7] Yet, these costs are allocated in the fuel clause to all customer classes. This means that the residential customers are providing subsidies to the commercial and industrial customers. Also, very few low-income customers subscribe to CSGs. This means that low-income customers are providing subsidies to the commercial and industrial customers.

The excessive costs for distributed solar resources, and their burden on low-income and residential customers, are not unique to Minnesota. We note of interest the December 13, 2021 Proposed Decision issued by ALJ Hymes of the Public Utilities Commission of California, Rulemaking 20-08-020, which recommended that the export rates for net metered projects be reduced by 64-84%, and that the reduction would apply to new systems, and further apply to existing net metered systems after they have been in operation for 15 years. This decision noted the importance that the rates be based on avoided costs, that the current tariff structure is unsustainable and disproportionately burdens low-income customers and non-participants.[8]

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[7] https://www.xcelenergy.com/staticfiles/xe-responsive/Environment/Renewable%20Energy/2021.12.06%20SRCMN%20Dashboard.pdf

[8] See, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M430/K903/430903088.PDF . See, page 111 for the 64 to 84 percent estimate based on use of the Avoided Cost Calculator.

B. Queue Congestion Caused by Increasing CSG Applications

The explosive CSG growth alongside policy development has led several of the Company's feeders that ring the Twin Cities Metropolitan Area to become saturated with DER. This is partly due to CSG rules, which require CSG subscribers to be located in the county where the CSG is located or an adjacent county, naturally leading CSGs to be concentrated in certain areas adjacent to counties with larger customer bases and where lower cost land is available. The result of this has been that many projects now have been placed on hold to allow for studies of projects earlier in the same queue, and customers' smaller systems have encountered their own challenges, as we note in more detail below. The substantial growth in a short period of time and concentration of CSGs on a small portion of our distribution system has impacts. Notably, as a result of this DER saturation, it is taking increasingly more time and expense to determine how to safely and reliably interconnect each project. The Company is facing distribution grid and DER interconnection issues that very few other utilities in the U.S. have experienced or addressed.

We have been transparent with developers and the Commission about the volume and concentration of CSGs and about the extensive length of time it will take to serially review CSG applications in our many filings in the CSG docket and in the MN DIP docket. These issues have also been discussed in our DER Quarterly Workgroup meetings, and the information has been conveyed to developers through our online Hosting Capacity map and our public DER queue report that is updated monthly.

The high saturation of CSGs on some of these feeders is now having a higher impact on roof-top solar systems, which must wait their turn for study in queue because even a small system of 10 kW could potentially have material impacts on the ahead-in-queue applications. The irony is that one of the stated goals of the CSG program is that it would be a fallback option for those who could not install solar systems on their own property, but in some areas the CSG program is now preventing or delaying customers from installing roof-top solar on their own house or business such as is the case with the current application submitted by Nokomis here.

C. Other States Have Addressed These Issues

Minnesota is not alone in facing long queue lengths as a result of the serial review process, large number of DER applications, and other factors. Successfully addressing these issues will likely require a rigorous approach with a combination of actions. We discuss in Attachment A experiences of Duke Energy in the Carolinas, and the states of Oregon and New York with their long queue lengths and actions they have taken. We note that Duke Carolinas has a serial review process and had about 730 MW of

DER "on hold" in their interconnection queue. Oregon had a 90-fold increase in their DER interconnection applications. New York had over 1,700 solar projects in interconnection queues. We reiterate the point from our Introduction that we are not asking that the Commission take action in this docket on the approaches we outline below, but it is important to be aware of these different approaches to better understand the context of the current Complaint. Examples of changes that other utilities have implemented include the following:

- Duke Energy has implemented mandatory cluster studies, similar to our proposed mandatory Cluster Study process in the 16-521 Docket.
- Duke Energy's "Methods of Service Guidelines" does not allow DER generation backfeed across any field regulators. In Oregon, Community Solar interconnection applications are only allowed if the capacity of the proposed project, together with all other DER in local areas, is less than 100 percent of daytime minimum load. As discussed in Attachment A, these allow less DER compared to the Company's proposal for a DER Technical Planning Limit and an Open DER Capacity Limit in the 16-521 Docket.
- Oregon reduced the QF rates from $85 / MWh to $40 / MWh as part of their approach. In California, the ALJ Proposed Decision recommends a 64-84 percent reduction in export rates for DER. Our current CSG ARR Bill Credit Rate is up to $158.67 / MWh, and the VOS 2021 Vintage Bill Credit rate which is a levelized $110.40 / MWh, both of which are more than twice the market rate for solar power.
- Duke Energy no longer allows applications to progress where the System Impact Study shows that reconductoring greater in length than 0.5 miles would otherwise be needed.
- Duke Energy reduces nameplate capacity of 40 percent for certain projects in queue with an ability for parties to assign the remaining capacity.
- Duke Energy allows applications to be studied out of serial queue review order where doing so makes some projects more likely to be technically and economically viable. (Part of a Settlement Agreement).

D. Company Proposals in the 16-521 Docket

The Company recognizes that the current MN DIP process has problems, and we have proposed a number of suggested approaches to improve the process. These currently await Commission action. These proposals include mandatory Cluster Studies; application of an overall DER Technical Planning Limit; and an Open DER Capacity Limit. The DER Technical Planning Limit would initially be set so that the aggregate nameplate capacity of all DER installed or ahead in queue plus the project being studied may not be more than the Daytime Minimum Load (DML) plus 80 percent of the equipment rating of either the substation transformer or feeder. The Open DER Capacity Limit, implemented in conjunction with the DER Technical Planning Limit, would reserve capacity for net-metered DER systems 40 kW or less that comply with the 120% rule.

Nokomis has proposed abolition of the serial review process under MN DIP and switching to a parallel review for all interconnection applications in this same docket. Since the Nokomis Complaint is directly related to several other matters that are already in front of the Commission, we believe it is prudent for the Commission to consider these MN DIP-related matters holistically, provide further direction in the MN DIP docket, and dismiss the Nokomis Complaint for the reasons discussed in more detail below.

II. NOKOMIS COMPLAINT

A. Project Details

For the matter at hand, as detailed in the Complaint and its attachments, on June 4, 2021, Nokomis submitted an interconnection application under the MN DIP process for its proposed 1 MW customer-sited net-metered project. The location of the project, Ole Solar, is on the NOF071 feeder. At that time, the June 1, 2021 Public DER Queue report on our website, under the tab "Application by Feeder," showed that there were three applications "on hold" on feeder NOF071. The queue report also showed that, due to the MN DIP serial review process, the next application to be submitted on this feeder would be expected to take about 900 days (or 2.5 years) for an interconnection agreement to be issued. Under MN DIP, the expected time frame for a project that is first in queue and needs to be studied is about 300 days from date the application is Deemed Complete until it is issued an interconnection agreement. See, Attachment B, which details certain MN DIP timelines. With serial review, for a project later in queue, the generally expected time frame under MN DIP is 300 days per each application ahead of it, plus its own 300-day period, with a need to factor in additional time for MISO review.

After Nokomis's application for Ole Solar was Deemed Complete, the Company performed the Initial Review Screens, which the project did not pass. We then notified Nokomis that the application was placed "on hold" because there were unstudied projects ahead in queue and that it was expected to have a 600 Business Days delay to the application timeline. This 600 Business Day timeframe is roughly equivalent with the 900-day notice provided in the public queue report at the time that the application was submitted. This timeline is consistent with the MN DIP and is not related to any delay on the part of Xcel Energy.

Nokomis filed its Complaint to contest the 600 Business Day timeline, contending that our implementation of the serial review process, by putting this project "on hold," is not authorized by MN DIP. Generally, Nokomis argues that the serial review process used by the Company to study applications in queue is not consistent with MN DIP, and that the 600 Business Day expected delay shows that the Company is not using reasonable efforts to advance its interconnection application.

As discussed in the sections below, there are no reasonable grounds and no public interest to investigate the Nokomis Complaint, and the Company requests that the Commission dismiss the Complaint. The Company's conduct in processing interconnection applications in general, and the Ole Solar application in particular, is consistent with MN DIP.

The NOF071 feeder is a capacity-constrained feeder with high CSG saturation. The December 1, 2021 Public DER Queue Report shows that NOF071 is on the list of capacity constrained feeders (5.7 percent of all feeders are on this current list), and is on the list of feeders where aggregate DER exceeds daytime minimum load (15.3 percent of all feeders are on this list).[9] Table 1 below shows the Public DER Queue for feeder NOF071 as of December 1, 2021. The Ole Solar project is on row 17, and this row is highlighted below. There is a total of over 7 MW of operational DER generation ahead of Ole Solar, 1 MW ahead being constructed, 1 MW being studied (row 13), 2 MW of projects ahead in queue not yet being studied (rows 14 and 16), and less than 20 kW of projects behind in queue.

[9] These lists can be located on the Public Queue Excel spreadsheet under Known Capacity Constraints tab.

Table 1: Public Queue 12/1/21 for Feeder NOF071

Row #	Application Number	Project Type	Date Application Deemed Complete	Interconnection Process Track	Proposed DER capacity (kW AC)	Application Status	Customer Full Name
1	3127720	Solar*Rewards Community	1/4/2016 23:01	Pre-MNDIP	1000	Step 8: Active	Northfield CSG3, LLC
2	3127721	Solar*Rewards Community	1/4/2016 23:01	Pre-MNDIP	1000	Step 8: Active	Northfield CSG4, LLC
3	3127722	Solar*Rewards Community	1/4/2016 23:01	Pre-MNDIP	1000	Step 8: Active	Northfield CSG2, LLC
4	3127580	Solar*Rewards Community	1/4/2016 23:01	Pre-MNDIP	1000	Step 8: Active	Northfield CSG1, LLC
5	3127602	Solar*Rewards Community	1/4/2016 23:01	Pre-MNDIP	1000	Step 8: Active	Northfield CSG5, LLC
6	3127231	Solar*Rewards Community	12/5/2018 23:06	Pre-MNDIP	1000	Step 8: Active	Chub Garden LLC
7	3128525	Solar*Rewards Community	3/13/2019 23:08	Pre-MNDIP	1000	Step 8: Active	Hyacinth Solar, LLC
8	3498665	Solar*Rewards	2/5/2020 6:47	Simple	7.25	Permission to Operate	N/A
9	3897946	Solar*Rewards	9/28/2020 11:28	Simple	5	Permission to Operate	N/A
10	4124406	Solar*Rewards Community	11/5/2020 13:16	Fast Track	1000	Design and Construction	MN CSG 2019-77 LLC
11	4123251	Solar*Rewards	11/12/2020 9:40	Simple	5.584	Permission to Operate	N/A
12	4225667	Solar*Rewards	12/21/2020 10:18	Simple	2.03	Metering and Testing	N/A
13	4218616	Solar*Rewards Community	1/14/2021 12:25	Fast Track	1000	Initial Engineering Screens	DIVOCSG 17 LLC
14	4193986	Solar*Rewards Community	1/14/2021 14:17	Fast Track	1000	On Hold	SV CSG Northfield, LLC
15	4387001	Solar*Rewards	4/13/2021 9:06	Simple	4.886	Permission to Operate	N/A
16	4347588	Solar*Rewards Community	5/6/2021 15:57	Study	1000	On Hold	Johnnyvale Garden LLC
17	4498403	Distributed Generation	6/17/2021 17:37	Fast Track	1000	On Hold	N/A
18	4507616	Distributed Generation	7/8/2021 9:46	Simple	8.41	Facilities Study	N/A
19	4455139	Distributed Generation	7/13/2021 10:20	Simple	3.77	Metering and Testing	N/A
20	4709613	Distributed Generation	10/20/2021 11:06	Simple	7.672	Initial Engineering Screens	N/A

This Queue Report highlights that the underlying root cause for the long expected time frame to process the Ole Solar application is the high amount of CSGs already interconnected and ahead in queue on this feeder.

We address the specific issues noticed for comment by the Commission below.

B. Commission Jurisdiction

The Commission has jurisdiction over the subject matter of the Complaint, consistent with Minn. Stat. § 216B.09 (allowing the Commission to consider complaints with respect to services provided by utilities). The general nature of the complaint relates to the application submitted pursuant to MN DIP and under our MN DIP tariff, as developed in the 16-521 Docket. These applications are subject to the Company's tariffs that the Commission has approved. Our tariffs, and the MN DIP interconnection process are regulated by the Commission.

C. Analysis on "Reasonable Grounds" and "Public Interest"

The November 18, 2021 Notice requests comments on reasonable grounds to investigate the allegations raised in the Complaint as well as on public interest to investigate the allegations upon the Commission's own motion. The "reasonable grounds" standard applies to Formal Complaints under Minn. R. 7829.1800, Sub. 1, while the "public interest" standard applies to Investigations under Minn. Stat. 216B.17. Subd. 1, which allows the Commission to begin an investigation also on its own motion.

Our understanding is that the Notice includes both standards for the following situation. If the Commission were to determine that there are no reasonable grounds to investigate a Formal Complaint under Minn. R. 7829.1800, Sub. 1, depending on the facts, the Commission could find that there is public interest for an investigation. For example, in a hypothetical situation different from the facts here, the Commission could believe that the factual allegations suggest a violation of law, but because the issues involve policy or impact a large number of stakeholders or a whole program, the Commission may conclude that there are no "reasonable grounds" to allow the Complaint to proceed, but instead the Commission could still investigate the allegations on its own motion if it determines this is in the public interest under Minn. Stat. 216B.17. Subd. 1.

For the purposes of this proceeding, we do not think there are significant material differences between the "reasonable grounds" standard and the "public interest" standard. We believe there are neither reasonable grounds nor public interest for the Commission to investigate the Nokomis allegations. Accordingly, the remainder of these Comments use the terms "public interest" and "reasonable grounds" interchangeably.

D. The Interconnection Process in Minnesota

The MN DIP, which went into effect in June 2019, aims to (among other goals) provide a set of generic interconnection standards to allow for low-cost, safe, and standardized interconnection of DER. One such standard requires serial review of applications.[10] The number of applications submitted can exceed the current distribution capacity in some areas, as illustrated by the number of projects in queue for serial review or "on hold." An unintended consequence of the serial review requirement of MN DIP has contributed to deep application queues – and small DER applications getting "stuck" in these deep queues behind larger projects, and/or facing significant system upgrade costs to interconnect their systems. Eliminating the CSG adjacent county rule would not solve the problem of congested feeders; instead, it would exacerbate the problem by bringing this same problem to a whole new set of feeders.

Long queues on saturated feeders can even impact customer-sited net-metered projects that will operate in parallel with the Company, even though they do not plan to export energy to the Company. These projects are still subject to the MN DIP process and can materially impact those ahead in queue if studied out of queue order.[11] For example, the amount of generation to load could require different upgrades to be assigned to each project than if they were reviewed serially, or in some cases the first project studied could be able to get capacity by paying for upgrades, but the next project being studied may need to pay for a new feeder which would be substantially more expensive.

Even when the Company complies with the MN DIP timelines and the MN DIP process, there are challenges to the length of time projects later in the queue remain stagnant as other projects ahead in queue are reviewed. This volume of DER applications combined with the MN DIP serial review process have exacerbated

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[10] MN DIP requires the Area EPS Operator (i.e. Xcel Energy) to maintain a single, administrative queue and manage the queue by geographical region (i.e. feeder, substation, etc.). This means that all DER applications, including community solar gardens and on-site solar systems, are being studied serially based on their queue position (as noted in MN DIP 1.8.3).

[11] MN DIP 1.1.1 states: "*The Minnesota Distributed Energy Resources Interconnection Process (MN DIP) applies to any Distributed Energy Resource (DER) no larger than 10 MW interconnecting to, and operating in parallel with, an Area EPS distribution system in Minnesota.*" Consistent with this, the State of Minnesota Technical Interconnection and Implementation Requirements (TIIR), which includes Technical Requirements to implement MN DIP, states in section 1.2: "*1.2 Scope. The statewide TIIR applies to all DER technology sized at 10 MW and less in AC nameplate capacity that is interconnected at secondary or primary distribution voltages and is operated in parallel with an Area EPS. The TIIR applies to DER for any duration of parallel operation. Non-exporting DER that operate in parallel with the Area EPS are subject to these technical standards.*"

interconnection challenges and customer complaints. In addition, higher DER penetration areas require more complex engineering analysis for applications.

Engineering review of interconnection applications (projects) is essential before they are allowed to interconnect with the distribution grid. This ensures the additional generation can be added safely and have no adverse impacts on other customers or the overall reliability of the system. The serial review process, specifically, is appropriate because it allows us to determine the incremental changes we would need to make to our network to accommodate safe and reliable interconnection of a project.

At higher DER levels, system modifications for projects later in queue are sensitive to the system modifications made for projects ahead of them. Tighter capacity may require system upgrades for a later project, or a later project may benefit from an upgrade made for the project ahead of it. For this reason, a project must be put on hold until the serial interconnection review of the projects ahead in queue is complete and they have a signed interconnection agreement[12] or have withdrawn. This serial review provides critical information that we need to effectively study the next in queue project and also limits re-studies and queue "churn" by providing reliable data inputs into the next screen or study. In addition, placing projects on hold allows them to wait for possible capacity to open up. For example, there may be extensive voltage limitations for a larger DER ahead in queue, and this larger project in some situations may withdraw, opening up additional capacity for smaller DER or other large DER in queue in more favorable locations. However, this will not be known until each project is studied serially in queue order.

There are over 450 MW of projects in queue currently waiting for serial review. It seems that solar developers are not fully utilizing the tools available to identify (and thus, avoid) the already-constrained feeders, typically with deep existing queues. In an effort to help guide DER projects to the viable parts of our system, we regularly publish a hosting capacity map and tabular results as well as a monthly DER queue with a list of constrained feeders. Yet, we continue to receive new applications on these very congested feeders with long queues – and developers continue to express surprise or disdain when we inform them that there is a long queue ahead of their application.

Besides making fundamental program changes, such as reducing the Bill Credit rate for CSGs or otherwise decreasing or curtailing the number of applications, we believe

[12] The terms interconnection agreement and MN DIA are used interchangeably. The MN DIA is the interconnection agreement for projects subject to the MN DIP.

there are other actions that would address the current queue clog and help avoid a similar situation from occurring in the future on other feeders. We have proposed a change to MN DIP that would require groups of projects in queue for a specific feeder to be studied together as a "cluster" in certain circumstances and to also allow us to use our proposed DER Technical Planning Limit and Open DER Capacity Limit. The outcome of a Cluster Study would be the distribution system upgrades that are necessary to accommodate the group of projects. We have proposed making the Cluster Study mandatory because developers have been largely unwilling to voluntarily participate in a cluster study, especially if it involves multiple developers. They typically, and rationally, try to determine where in the queue they are, where the other projects in the potential study are located, and deduce if their project would benefit from this type of analysis. With each applicant acting in its own self-interest, it is unlikely that the voluntary method of Cluster Studies will ever gain traction to help address the current situation.

Together, our proposals would have several benefits. Mandatory cluster studies would facilitate faster review times than individual, sequential study of each project. It would also eliminate "queue squatting" by projects that do not want to lose their spot in line for space on a particular feeder – forcing them to decide to be part of the cluster outcome or get out of the queue so the other projects may progress. The DER Technical Planning Limit would allow us to have a reasonable margin to better fulfill our statutory obligations for safety, reliability and adequacy of service, and the Open DER Capacity Limit would provide increased certainty for smaller DER projects. While this will not resolve the issues surrounding the cost and bill impacts of the program or the cost of interconnection for all applicants, it would be an important step to help clear queues and give interconnection answers in a faster timeframe for parties later in queue.

E. Serial Review and On Hold Process Following the Queue Order Are Consistent with MN DIP

Absent reform, the Company is bound to following the MN DIP, as it has done in the case of Nokomis's application in question. The MN DIP specifically authorizes serial review and requires use of the queue process. MN DIP requires that queue position be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection, and to establish conditional interconnection capacity. Further, if a cluster process is not used, the interconnection application needs to be studied serially. Pertinent MN DIP provisions from tariff sheet 10-180 include:

1.8 Queue Position

...

1.8.3 The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.) This administrative queue shall be used to address Interconnection Customer inquiries about the queue process. If the Area EPS Operator and the Interconnection Customer(s) agree, Interconnection Applications may be studied in clusters for the purpose of the system impact study; otherwise, they will be studied serially.

Consistent with the use of the queue process, the MN DIP System Impact Study (SIS) Agreement (at tariff sheet 10-233) provides as follows:

7.0 If the Area EPS Operator uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all Distributed Energy Resources (and with respect to paragraph 7.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

7.1. Are directly interconnected with the Area EPS Operator's electric system; or

7.2. Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

7.3. Have a pending higher queued Interconnection Application to interconnect with the Area EPS Operator's electric system.

There are three applications in queue ahead of this Nokomis application for which interconnection agreements have not yet been issued. The Company reached out to each project to determine if they would be willing to participate in a Cluster Study. Under MN DIP 1.8.3, cluster studies are voluntary and require the consent of each party to the cluster study. Nokomis declined to participate in the Cluster Study as have the first (row 13 in Table 1 above) and second in queue project waiting to be studied (row 14 in Table 1 above). Accordingly, there was no agreement on a Cluster Study and therefore under MN DIP 1.8.3 a serial review process must be used.

As shown in the excerpts above from the SIS Agreement, when a SIS is performed, it must identify Upgrades associated with the projects ahead in queue or already interconnected. The only way to determine the Upgrades associated with the projects ahead in queue is to perform a SIS for each of those projects in serial order and have some level of confidence that the project will still proceed to interconnection by signing the interconnection agreement. This is the serial review approach that the Company has consistently applied to all MN DIP interconnection applications that exceed 40 kW, including the Nokomis Ole Solar project, and this fully complies with MN DIP. To do otherwise would potentially result in several rounds of study (which could also trigger further complaints to the Commission), and lead to us issuing interconnection agreements with indicative estimated costs far different from actual costs, if projects ahead in queue drop out and the scope of work changes as a result.

One of the goals of MN DIP was to get better indicative cost estimates at the time of the signing of the interconnection agreement, and that goal would be compromised by not adhering to the serial review process, unless parties have agreed to a Cluster Study.

The serial nature of the review requires that projects are studied one at a time. The results of the SIS for the first in queue project, showing the necessary Upgrades for interconnection, will then set a factual baseline needed to start the SIS for the next in queue project. This process is an inherent part of the MN DIP. Engineering review of interconnection applications (projects) is essential before they are allowed to interconnect with the distribution grid. This ensures that additional generation can be added safely, without adverse impacts on other customers or the overall reliability of the system. The serial review process with putting later in queue projects on hold, specifically, is necessary because it allows the Company to determine for each project the incremental changes we would need to make to our network to accommodate safe and reliable interconnection.

The Company uses the term "on hold" to describe this process, where a later-in-queue project must wait for the determination of what Upgrades will be made to our network to accommodate each of the ahead-in-queue projects before a SIS can be started for that particular project. Although the term "on hold" does not appear in the MN DIP, the on hold concept is inherently consistent with the MN DIP.

When the MN DIP was being developed in the 16-521 Docket, parties specifically addressed how to approach situations where multiple interconnection applications are in the same queue. That history is important here, as it further supports the Company's implementation of the serial review process when there are multiple applications in the same queue and waiting for ahead-in-queue projects to have signed Interconnection Agreements before proceeding to study the next-in-queue project. We provide in Attachment C a review of a chronology of filings on this issue. As shown in Attachment C, as the MN DIP was being developed, Parties interchangeably used the terms "serial" and "sequential" review to mean the same thing. The comments recognized that typically all projects would be processed sequentially. Further, Xcel Energy was consistent in noting that serial review would require that projects behind in queue would need to wait until projects ahead in queue had a signed Interconnection Agreement. Otter Tail Power referred to this waiting as being on hold.

The Joint Movants in that docket (Interstate Renewable Energy Council, Inc. (IREC), ELPC and Fresh Energy) recognized that projects later in queue, even small projects, may be delayed due to management of the queue, if there are several larger projects ahead in queue. The Joint Movants advocated for a change to the proposed MN DIP 1.8 on serial review so that an interconnection customer behind in queue would have the choice of either waiting to be studied for interconnection until projects ahead in queue had executed Interconnection Agreements, or selecting an option that the Area EPS Operator proceed with the interconnection study as long as the Interconnection Customer would be responsible for any costs for restudies and different interconnection costs caused by ahead in queue projects withdrawing from the queue. Wind on the Wires (WOW) noted that this change proposed by the Joint Movants would raise other issues that would need to be addressed, if there would be three or more projects in the same queue. The proposed changes of the Joint Movants were not adopted, leaving the serial review and waiting for the results for the prior in queue projects (executed Interconnection Agreement or withdrawal) as the only option under MN DIP.

To help address issues of potentially having multiple interconnection applications in the same queue, the Parties agreed to have detailed queue reporting, which today is part of the Public DER Queue reporting. The Commission ultimately approved the wording of MN DIP 1.8 by adopting the Staff proposed wording in its May 2018 draft of the MN DIP. The edits by Staff recognize the tradeoff with the public reporting of queue, the queue position based on conditional interconnection capacity, and the serial processing/studying of interconnection applications except where parties agree to cluster study for the SIS. According to Staff, these components give utilities the requested flexibility in managing the queue and reporting queue details.

1. *MN DIP Is Based on SGIP, Which Also Uses Serial Review*

The Small Generator Interconnection Procedure (SGIP), as adopted by the Federal Energy Regulatory Commission (FERC), was used as a basis for the beginning draft of the MN DIP. As a result, it is appropriate to implement MN DIP in a similar manner as SGIP when the wording and issues are the same. The pertinent SGIP language on use of the queue, serial review, and required concepts in the SIS were basically left unchanged in the MN DIP.

Following are excerpts of the initial redlines to SGIP as submitted and proposed for the MN DIP by the Joint Movants in their February 1, 2017 filing (dated January 30, 2017) in Docket No. 16-521, showing in redline how the MN DIP would be different in wording from the SGIP on the queue concept. On this pertinent issue, the proposed language aligns closely with the final MN DIP language adopted by the Minnesota Commission, although formatting and paragraph numbering slightly changed.

~~1.5~~1.8 Queue Position

The ~~Transmission Provider~~Area EPS Operator shall assign a Queue Position based upon the date-and time-stamp of the Interconnection ~~Request.~~ Application. The Queue Position of each Interconnection ~~Request~~Application will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The ~~Transmission Provider~~Area EPS Operator shall maintain a single queue ~~per geographic region.~~. At the ~~Transmission Provider's~~Area EPS Operator's option, Interconnection ~~Requests~~ Applications may be studied serially or in clusters for the purposes of the system impact study.

~~1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP~~

Subject to the provisions of sections 1.5, 1.6, and 1.7, Generating Facilities shall retain the Queue Position assigned to their initial Interconnection Application throughout the review process, including where moving through the process covered by Section 2 and 0.

Pursuant to this language from SGIP adopted in MN DIP, transmission providers use a serial review process, which means the same as a sequential review. We include in Attachment D an excerpt of a multi-authored article "*Updated Small Interconnection Procedures for New Market Conditions,*" published in December 2012 by the National Renewable Energy Laboratory (NREL).[13] At article pages 34-36, the authors explain how the serial review process is used under SGIP, and this aligns with how the Company has been implementing MN DIP. The article specifically notes that under the SGIP serial study process, an interconnection request may not be studied until all ahead-in-queue generators are studied, and cautions that the serial study process can lead to long delays when the volume and interrelatedness of interconnection requests increases. The article states:

> As discussed above, the SGIP uses a serial study process for determining interconnection requirements for a particular generator.[144] Under a serial study approach, interconnection requests are studied one at a time, on a first-come, first-served basis. The order of requests received is made publicly available through posted interconnection queues.[145] Under this approach, an interconnection request may not be studied until all queued-ahead generators have been studied. ….
>
> A second factor is the necessity to complete the interconnection of queued-ahead generators to determine the anticipated system configuration for the study of later-queued generators. This is an important consideration, because upgrades that may be required to interconnect a generator that is ahead in the queue may facilitate the interconnection of generators further behind in the queue. On the other hand, if a generator earlier in the queue decides not to move forward with its interconnection, and therefore upgrades that would have been completed to accommodate that generator are not completed, the study of later-queued generators would not assume the existence of those upgrades. The result is that a generator further back in the queue may be responsible for the completion of the upgrades that would have otherwise been completed to facilitate the interconnection of the queued-ahead generator, if it had gone forward.

[13] https://www.nrel.gov/docs/fy13osti/56790.pdf

> There may also be a need to re-study the later interconnection requests. A high number of speculative projects in an interconnection queue that drop out during or after the study process can result in a ripple effect that can impact and necessitate restudy of applicants further back in the interconnection queue. This lengthens the serial study process and increases costs. In sum, the requirements for a generator further back in the queue may not be able to be determined until the status of all generators that are ahead in line have been determined.
>
> The serial study process may work well in situations where a utility is a) processing a low volume of interconnection applications such that existing resources are sufficient to timely handle the volume of interconnection requests being received, and b) generators seeking interconnection are sufficiently independent such that the ability to move forward with studies is not significantly delayed by the need to process earlier interconnection requests to determine the base case for generators farther back in the queue. The serial study process becomes less efficient when the volume of interconnection requests and interrelatedness of interconnection requests reaches a point where significant delays in processing interconnection requests results. Under these conditions, the serial study process can lead to long delays, and other options may need to be explored.[146]

This article, in footnote 146, also noted study delays of 6 to 7 years under the serial review process.

Similarly, in California under the SGIP, the California ISO (CAISO) filed a petition with FERC noting long queue lengths and long timeframes to review pending interconnection applications, along with its proposal to implement mandatory cluster studies as part of its proposed approach to address these issues. The problem was that CAISO was experiencing a high number of interconnection applications – going from ten in 2008 to 130 in 2010 – and the serial review process in SGIP was resulting in a long study backlog. The situation with CAISO was correspondingly similar to what the Company is facing in Minnesota, where about 15 percent of our feeders have high levels of active and pending CSG applications. The CAISO situation was explained in FERC Order of December 16, 2010 in the matter of *California Independent System Operator Corporation*, Docket No. ER11-1830-000 (FERC 2010 Order), which first noted as background that the SGIP uses a serial review process, and then continued:

> Under the SGIP's serial study process, each proposed generating facility is studied one at a time in succession, and the level of analysis to determine required transmission upgrades is performed for each individual generator. Each successive generation project is studied based on a transmission system that assumes the upgrades required by preceding projects are in place. Thus, according to CAISO, each project has its own separate timeline, and studies for a particular project cannot be undertaken until studies for previous electrically related projects are completed. ...
>
> Under a serial study process, each individual interconnection request is studied separately in order to determine its effects on the transmission system. If projects that are higher in the interconnection queue drop out of the queue, CAISO argues it may become necessary to perform repeat studies, causing delay and additional costs to interconnect. ...
>
> CAISO further states that as more projects enter the queue, a study backlog develops and becomes larger because all subsequent projects must wait for studies of all electrically related earlier projects to be completed. In combination with the discrete time periods provided for

> interconnection customers to make decisions regarding how and whether they wish to proceed in the interconnection process, CAISO states that simply devoting more resources to the study process will not relieve the backlog. In addition, CAISO points out that projects withdrawing from the process can further exacerbate the delays, because they require restudy of all later projects, whose studies assumed that the transmission upgrades associated with the withdrawing project would be completed.[14]

CAISO was not violating SGIP by following the required serial review process, which resulted in long study queues with each project waiting their turn to be studied. Neither have we been violating MN DIP by following a similar approach. Similar to CAISO seeking to modify SGIP to implement mandatory cluster studies to help address a high number of interconnection applications, we are seeking to modify MN DIP in Docket No. 16-521 to implement mandatory cluster studies to address the high number of interconnection applications we experience on specific feeders.

Nokomis, at pars. 57-59 of its Complaint, asserts that SGIP does not provide for studying projects one at a time. The above authority clearly shows that the FERC SGIP requires one at a time study review. The quote that Nokomis provides is from FERC's May 12, 2005 Order "*Standardization of Small Generator Interconnection Agreements and Procedures*" at 70 Fed. Reg. 34,189, 34, 207. Nokomis cites to portions of pars. 178 and 180 of that Order, but taken in context it has misapplied the quotations. FERC was responding to a concern that smaller projects that would not need upgrades in order to interconnect could be stuck in long queues. Implicit in the FERCs discussion is the premise that the small project would not be subject to upgrade cost allocations and therefore could have the interconnection completed without waiting for ahead in projects to be studied in queue. This is similar to the parallel review process we have established under MN DIP for small projects, discussed below. But, this type of parallel review process cannot be used for applications that have material impacts on prior-in-queue projects, such as the 1 MW Nokomis Ole Solar application, just as the parallel SGIP process would similarly not be available where those behind in queue would require Upgrades in order to interconnect.

Nokomis in footnote 25 further cites to the FERC November 30, 2005 Order "*Standardization of Small Generator Interconnection Agreements and Procedure: Order on Rehearing*", at 70 Fed. Reg. 71,760, 71,767-80, at par. 61, to assert that utilities must manage their queue so that projects lower in queue can proceed ahead of projects higher in queue. The actual FERC language is far different than summarized by Nokomis, and has no relation to the current dispute. The FERC language had to do with allowing projects to be interconnected, and that "when possible" a later in queue project could be interconnected before the necessary work to interconnect the ahead

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[14] FERC 2010 Order, par. 5, note 9, and par. 6.

in queue project was done. This again is consistent with our parallel review process for smaller projects, but cannot be applied here because of the need to study the Nokomis project in queue order.

2. *We Have Implemented a Parallel Review Process for Smaller Projects*

Even though the Company is entitled to use the MN DIP serial review, we have found a way to allow some smaller projects to move forward if they are behind other projects in queue, under our parallel review process. Our engineering team established a process to evaluate these smaller systems simultaneously when there is no material impact to other interconnection applicants ahead in queue. For instance, when we initially implemented this limited parallel or simultaneous review, all Simplified Process track applications (≤20 kW), where the aggregate of existing and ahead-in-queue generation does not exceed the feeder or substation rating, were able to move forward in the interconnection process and be reviewed simultaneously with projects ahead in queue. In addition, we continued to explore opportunities to increase the project size threshold up to 40 kW and did so in August 2020. We also note that there are instances where the queue is significantly deep and the distribution system constrained, which means that even some small projects must wait in queue for the serial review. With certain feeders becoming saturated with DER, our December 2021 Public Queue Report shows that 65 projects under 40 kW are on hold on 27 feeders.

We do not support broadening the scope of the parallel study review because it will result in a less accurate assessment of the work and upgrades required for interconnection, often underestimating the indicative cost compared to the actual costs. In many cases this can result in substantially larger actual costs to interconnect than conveyed in the indicative cost estimate – and under parallel review, this significant increased work and cost may only become evident after the behind-in-queue project has already spent substantial funds for construction.

3. *Pre-MNDIP Process Does Not Resolve the Issue at Hand*

Nokomis at paragraphs 49-55 of its Complaint points to the Company's CSG Section 9 tariff to argue that although there was a queue requirement for pre-MN DIP applications, the Company performed parallel review of interconnection applications and did not wait for the ahead in queue to have a signed interconnection agreement. Nokomis notes that the Company interconnected over 700 MWs of DER under the pre-MN DIP process, and argues that based on similar use of language, there is no serial or sequential review provision under MN DIP.

There are fundamental differences between the pre-MN DIP process and the MN DIP process. Before MN DIP went into effect, the Company processed CSG applications under the Section 10 Interconnection tariff, as modified by the requirements in the Section 9 CSG tariff. Nokomis cites to the definition of "Study Queue" on CSG tariff sheet 9-68, which provides for the priority sequencing of Interconnection Applications for engineering studies. This provision was introduced into the tariff as part of the December 2015 tariff revisions to settle the co-location issue and provide that applications need to be "Expedited Ready" to have a queue position. Only when an application was "Expedited Ready" would it enter the study queue. The pre-MN DIP interconnection tariff and related CSG tariff applicable to pre-MN DIP applications, had specific additional language that required the Company to study projects simultaneously (Interconnection Agreement had to be issued within 50 Business Days), and to assume that all projects ahead in queue will have a signed Interconnection Agreement and proceed. The pre-MN DIP tariff also warned that the actual interconnection costs could be markedly different from the indicative cost estimate if any projects ahead in queue drop out. MN DIP does not include any such language.

The pre-MN DIP tariff provisions state:

> Sheet 9-68:
> "Interconnection Agreement Time Line" means: Where the conditions described in pars. 5-8 below are met, but beginning no sooner than 10 business days after the Initial Revised Tariff Effective Date the Company will within 40 days on a best efforts basis, and, but not more than 50 business days, provide an Interconnection Agreement. The Interconnection Agreement will then need to be signed by the applicant and countersigned by the Company.
>
> Sheet 9-68.7:
> iii. The engineering indicative cost estimate is based on the assumption that all projects ahead of the application in the Study Queue and already studied and passing engineering review will have a signed Interconnection Agreement and will proceed with all distributed generation capacity which the Company studied for those other projects. Note: If any Community Solar Garden application ahead of it in the Study Queue and so approved decides not to proceed with an Interconnection Agreement, the actual costs of engineering interconnection construction for the applicant's Community Solar Garden could be markedly different from the engineering indicative cost estimate. To help the applicant to assess the risk of this, the Company will provide to the applicant the total number of MWs ahead of it in the Study Queue at the time of providing the indicative cost estimate.

For additional context, it is important to note other differences in the way to process pre-MN DIP applications. The pre-MN DIP process for the CSG program limited applications to those that did not trigger a "Material Upgrade" threshold.[15] If this threshold was exceeded, applications received a "no capacity notice." As a result, many applications were withdrawn and therefore did not clog up the queue.

Additionally, the pre-MN DIP process for CSGs used in effect a cluster study review for many interconnection applications. Under the CSG program, initially applications could be co-located up to 5 MW. This meant that five 1 MW applications could be studied together on the same site and be jointly and severally liable for study and construction costs. This type of cluster study helped to process large volumes of applications in the early stage of the program. Further, this was at a time when the feeders were not yet saturated with DER, so that study process went smoother.

In comparison, under MN DIP we cannot use cluster studies without developer consent, and they have been hesitant to engage in that effort, which means that cluster studies typically are not performed under MN DIP. Further, under MN DIP we cannot cancel an application if it will require a Material Upgrade. Since the CSG program launch, approximately 15 percent of our feeders have also become saturated with DER. This high level of DER concentration causes more challenging engineering reviews, more costly interconnections, and clogging of the interconnection queue due to the need for serial review and a better-informed cost estimate for interconnection. For example, MN DIP requires the review of additional mitigations – including the addition of a new feeder, which under the pre-MN DIP process would have been a Material Upgrade. New feeders can be expensive and require further study analysis, and sometimes discussions with the MISO – and on occasion, with other utilities. Because developers continue to focus on a limited subset of our distribution system, these situations are becoming more and more frequent, slowing down the queue in certain parts of our service area.

We oppose the changes Nokomis proposed to MN DIP that would institute widescale parallel processing of applications, since this would result in high volumes of restudies, waste valuable engineering resources, and in many cases produce inaccurate cost estimates.[16] While parallel application processing might seem like a faster option, there are trade-offs between speed and accuracy that the Commission has previously recognized – and we have experienced first-hand with the interconnection process that was in place prior to MN DIP implementation. The Nokomis proposal would create an excess amount of potential re-work, only to

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[15] Tariff sheet 9-68.4. See, ORDER ADOPTING PARTIAL SETTLEMENT AS MODIFIED, *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program*, August 6, 2015.

[16] *See* suggested edits to MN DIP 1.8.3 and MN DIP 4.3.1 shown on page 4 of the Nokomis August 25, 2021 Comments.

produce virtually unusable results and inaccurate cost estimates because the studied conditions with prior-in-queue projects assumed in service do not represent the actual system conditions. This could also make the cost estimates resulting from the studies wildly inaccurate. Conversely, our proposed mandatory Cluster Study analysis resolves the underlying issues. We also believe the limited parallel application processing for some small Simplified projects is appropriate, working well and should be maintained as implemented.

To provide an idea of the impacts of the Nokomis proposal, we reviewed the number of restudies completed from 2015-2021 for pre-MN DIP projects. In total, there were over 200 restudies, which is approximately 15 percent of all studies conducted.

The Commission has previously recognized the trade-offs involved in the time to develop cost estimates and the accuracy of those estimates. The discussion at the August 12, 2021 Commission hearing regarding a CSG Formal Complaint also helps to inform this issue.[17] At that hearing (beginning at about 2:35:50 in the online video recording), there was discussion that the pre-MN DIP projects that went into commercial operation in 2020 had actual costs that were from *minus* 85 percent to *positive* 144 percent of the indicative cost estimate in the pre-MN DIP Interconnection Agreement.[18] Then there was discussion lead by questioning from Commissioner Schuerger about how under MN DIP there was a trade-off between time to develop the cost estimate and the accuracy of the estimate, and that under MN DIP there is a longer timeline to develop the cost estimate for each project, which can include a Facilities Study. The intent was to achieve greater accuracy in the MN DIP cost estimates compared to the pre-MN DIP estimates. The fact that it takes longer to develop the cost estimates under MN DIP compared to the pre-MN DIP process is clear, well-known, and was a deliberate part of the discussion in developing the MN DIP.

F. The Company Has Complied with Applicable Law and Regulation

Before addressing below the authority cited by Nokomis, we first describe why our conduct aligns with MN DIP.

The Company is allowed to use Good Utility Practice and engineering judgement in managing its distribution network and DER interconnections. As discussed during the

[17] Docket No. E999/C-21-125, *In the Matter of the Formal Complaint and Request for Expedited Relief by SunShare, LLC Against Northern States Power Company dba Xcel Energy regarding OsterSun Project*.
[18] http://minnesotapuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=1513

March 4, 2021 Commission hearing regarding a CSG Formal Complaint,[19] an engineering practice cannot be arbitrary or discriminatory:

> Commissioner Schuerger
> [Beginning at about 3:22:48]: ... *And as Staff has appropriately highlighted in the briefing papers, the MN DIP specifically acknowledges that not every detail of utility practices must be committed to tariff. We recognize that in the MN DIP. ...*
>
> [beginning at about 3:23:01] *So the question to me ... is are we seeing in this record utility practices that are arbitrary or discriminatory. And, I don't see evidence in this record before us that they are.*

We further note that the above excerpts align with the principle that the Company can use our engineering judgment to run the distribution network, and this goes to the core of what we do. We need to use this judgment to fulfill our statutory obligations to "*... furnish safe, adequate, efficient, and reasonable service*" (Minn. Stat. §216B.04). In doing so, we need to also " ... *comply with all applicable governmental and industry standards required for the safety, design, construction, and operation of electric distribution facilities....*" (Minn. Stat. §216B.029, subd. 1(d). Our tariff reflects the requirement that we use "good utility practices" (tariff sheet 6-27.1), and MN DIP also requires use of Good Utility Practices.

The State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR) further supports the need for the utility to exercise its own judgment: "*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.*" (page 1 of TIIR). The TIIR (at page 5) notes that it does not provide the complete description of all interconnection requirements. It states: "*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 Operator's web site, or contact the generation interconnection coordinator at the Area EPS Operator.*"

During the Commission hearing on June 17, 2021 in Docket No. 21-160, it was recognized that the MN DIP does not require that every practice of the Company be in the TIIR. Consistent with this, the Commission's August 13, 2021 Order in that docket, states in part: "*As Xcel hosts ever more distributed energy resources on its system – and specifically on a few feeders within its system— interconnection review becomes more complicated. Utilities must exercise judgment to ensure that any interconnection project will not impair the grid's safety or reliability.*"

[19] Docket No. E002/C-20-892, *In the Matter of a Formal Complaint and Petition for Expedited Relief by Sunrise Energy Ventures LLC Against Northern States Power Company d/b/a Xcel Energy.*

The reasonableness of waiting for the ahead-in-queue project to sign the interconnection agreement before proceeding with the engineering study is supported by the following:

- We have properly used our judgment to implement the serial review process, we have not acted in an arbitrary or discriminatory manner, and our implementation aligns with the serial review wording of MN DIP 1.8.3. Further, in the proceeding where this MN DIP language was developed, Xcel Energy and the Joint Movants each agreed that serial review means waiting for the projects ahead in queue to have a signed Interconnection Agreement before studying the next project in queue. Attachment C includes pertinent summaries.

- Without a serial review process and with changes to MN DIP consistent with this, the Company can reasonably assume that as projects are withdrawn, we would need to follow something similar to the pre-MN DIP process outlined above, requiring restudies of a multitude of projects. This would further hold up the queue and result in dramatic changes in interconnection costs after a signed Interconnection Agreement. The serial review has significantly reduced the number of restudies necessary and provided better cost estimates, which both are goals of implementing MN DIP.

- The pertinent MN DIP language on serial review is based on similar SGIP language. Under the SGIP serial review process, interconnection applications are studied one at a time, similar to how the Company processes the interconnection applications under MN DIP. The SGIP serial review has also resulted in long queue lengths of many years.

- The MN DIP allows for voluntary Cluster Studies. The Company has reached out to Nokomis on this, but Nokomis has declined to participate in a cluster study for this project as have others within the queue.

- The Company has proposed pending changes to the MN DIP in the 16-521 Docket to make Cluster Studies mandatory.

- Our process of waiting for a signed Interconnection Agreement is less stringent than the Duke interconnection practice. As noted in Attachment A, Duke in the Carolinas is more than twice the size of Xcel Energy in Minnesota, and has more utility scale DER installed. Under the Duke serial review process, Duke places projects on hold and keeps them on hold until the ahead in queue projects provide 100 percent certainty of funding for the upgrades associated with their applications. This provides far greater certainty than the Company's process of waiting for a signed Interconnection Agreement, because developers can cancel Interconnection Agreements and not be responsible for the contemplated Upgrades that were never constructed.

- A root cause of the problem with the long timeframe for processing projects in queues is the high Bill Credit rate under the CSG program, which attracts a high volume of applications.

1. MN DIP 3.3 and 3.4, Tariff Sheet 10-187

Nokomis alleges on page 1 and in pars.10 and 18-23, 29, 33-59 of the Complaint that it is entitled to a Supplemental Review of its interconnection application and that the Company does not have authority to place the Ole Solar application on hold. We have thoroughly addressed above why it is proper to put an application on hold during the serial review process. Nokomis seems to imply that this application on a congested feeder would pass a Supplemental Review and be allowed to leap-frog ahead of the other applications in queue to interconnect. This is not correct. As a courtesy, we have performed a Supplemental Review for the Ole Solar project and attach the redacted results in Attachment E. The non-redacted version will be made available to Nokomis through the Company's online application portal. This project failed the Supplemental Review, which means that a System Impact Study is needed. However, depending on what happens with the ahead-in-queue projects, once we have signed Interconnection Agreements with them (or if they withdraw), we may get different results in the Ole Solar Supplement Review if it were rerun at that time. Again, this supports putting the Ole Solar project on hold ahead of performing the Supplemental Review screen.

2. MN DIP 5.2.2, Tariff Sheet 10-206 (Reasonable Efforts)

Nokomis alleges on pages 1-2, and in pars. 25, and 60-65 of its Complaint that the Company has not used "Reasonable Efforts" to process the Nokomis interconnection application because the expected timeframe to study the project is about 600 Business Days.

Nokomis alleges that a projected 600 Business Day period to study the Nokomis application does not reflect reasonable efforts to meet the MN DIP deadlines. However, as MN DIP has no timeline for being on hold during serial review, there is no MN DIP violation. The length of time to be on hold is a function of the number of projects ahead in queue that need serial review. As described above, applications are temporarily placed on hold until all applications ahead in queue are fully studied and have either signed the IA or been withdrawn. It is only at that point that the Company has the information needed for study and the timeline is paused until the applications reenter active study. The deep queues and concentration of projects on a small proportion of feeders has resulted in extended timeframes for projects to move through the MN DIP process, even if all MN DIP deadlines are met. Again, we have proposed changes to address extended timeframes in the 16-521 Docket. Nokomis and two other impacted developers in the queue at issue have also declined to participate in a cluster study.

On this issue, Nokomis addresses the following language from the MN DIP:

> MN DIP 5.2.2
> The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.
>
> MN DIP 5.11 Comparability
> The Area EPS Operator shall receive, process and analyze all Interconnection Applications in a timely manner as set forth in this document. The Area EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers, whether the DER is owned or operated by the Area EPS Operator, its subsidiaries or affiliates, or others.
>
> Sheet 10-209, Definitions:
> Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests
>
> Sheet 10-206 – Definitions:
> Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

The provisions in MN DIP 5.2.2 do not apply when a project is waiting for its turn for a study in the queue, as there is no MN DIP timeframe for remaining in the queue for this purpose. And the length of time for waiting is directly influenced by the number of applications ahead in queue. MN DIP 5.2.2. only applies to using Reasonable Efforts to meet MN DIP time frames. Even though the "Reasonable Efforts" provision does not apply to the serial review process, we have used reasonable efforts to process the queue in alignment appropriately using our judgment to implement the serial review process, we have not acted in an arbitrary or discriminatory manner, and our implementation aligns with the serial review wording of MN DIP 1.8.3. Further, there is a pending proposal to improve the process.

Further, "Good Utility Practice" cannot violate current existing statutes, rules, standards, Company tariff, TIIR, Company Technical Specifications Manual (TSM), or national electric standards, codes, or certifications. And our policy to follow the serial review process does not violate any of them, because there simply is no such regulation that would prevent a utility in general or Xcel Energy from using serial review when a cluster study has not been agreed to by Interconnection Customers.

Also, consistent with MN DIP 5.11, we would certainly apply the same standard of having serial review be used to interconnect DER owned or operated by us, our subsidiaries or affiliates.

As further noted in Attachment A, Duke places DER applications on hold in its serial review process until the next ahead in queue project has 100% certainty of interconnection. Duke also has more interconnected DER in the Carolinas than we do in Minnesota. The core issue here is not the implementation of MN DIP, but the high concentration of CSG applications on a limited subset of the Company's feeders. As pointed out above, to resolve those problems, fundamental CSG program changes are needed, such as dramatically lowering the Bill Credit rate.

3. MN DIP Tariff Sheet 10-165

Nokomis cites to Minn. Stat. § 216B.1611 in the opening paragraph and par. 8 of its Complaint. This statutory provision is also reflected in MN DIP and at our tariff sheet 10-165. While Nokomis cites to this statute, it does not allege any violation of this statue.

This tariff sheet is the Foreword to the MN DIP and includes the following content:

> <u>Foreword</u>
> The Minnesota Public Utilities Commission is charged by Minnesota Statute §216B.1611 to establish generic, statewide standards for the interconnection and parallel operation of distributed energy resources of no more than 10 MW. These updated Minnesota interconnection standards strive to:
> 1) Establish a practical, efficient interconnection process that is easily understandable for everyone involved;
> 2) Maintain a safe and reliable electric system at fair and reasonable rates;
> 3) Give maximum possible encouragement of distributed energy resources consistent with protection of the ratepayers and the public;
> 4) Be consistent statewide and incorporate newly revised national standards;
> 5) Be technology neutral and non-discriminatory.
>
> At a minimum, these standards must:
> 1) To the extent possible, be consistent with industry and other federal and state operational and safety standards;
> 2) Provide for the low-cost, safe, and standardized interconnection of distributed energy resources;
> 3) Take into account differing system requirements and hardware; as well as, the overall demand load requirements of individual utilities;
> 4) Allow for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonably be assured of the reliable, safe and efficient operation of the interconnected equipment;
> 5) Establish a standard interconnection agreement that sets forth the contractual terms under which a company and customer agree that one or more facilities may be interconnected with the company's utility system; and standard applications for interconnection and parallel operation with the utility system.

In fact, several provisions from this tariff sheet support the Company's approach. These include providing the goals for a safe and reliable electric system, protection of the ratepayers and public, taking into account differing system requirements, and that the utility can reasonably be assured of the reliable, safe and efficient operation of the interconnected equipment.

4. Minn. Stat. § 216A.05

Nokomis cites this statute in par. 5 to support its argument that the Commission has jurisdiction over the Complaint. We agree with Nokomis.

5. Minn. Stat. § 216B.164, Subd. 8

Nokomis cites this statute in pars. 5 and 7 of its Complaint for the proposition that the Company is obligated to interconnect distributed generation projects under 10

MW. However, this obligation applies only if interconnection can be completed safely and reliably consistent with the MN DIP and Minn. Stat. § 216B.1611, which is what the Company has been doing.

There are no reasonable grounds raised in the Complaint, and it would not be in the public interest for the Commission to investigate the allegations. We suggest that the Commission rule on the various proposals related to MN DIP pending in the 16-521 Docket as the only viable approach, since the issues raised in Nokomis's complaint are also in front of the Commission in that proceeding and impact many pending (and future) applications. Under the interconnection tariff and MN DIP, we are prohibited from offering anything other than a Cluster Study as a solution to Nokomis, which we have done. We cannot operate outside of our tariff and give Nokomis special treatment compared to what is offered to other similarly situated developers, since this would constitute discriminatory conduct against other developers and also violate our tariff. If the current interconnection process does not work, the MN DIP process needs to be amended.

III. NEXT PROCEDURAL STEPS IF THE COMMISSION DETERMINES THAT IT IS IN THE PUBLIC INTEREST TO FURTHER EXAMINE THE ISSUES

We are unclear at this time what the next steps should be if the Commission were to determine that there are reasonable grounds to further consider some issues in the Complaint or it is in the public interest to further examine some of the issues set forth in the Complaint. The next steps may depend on what those issues are. Minn. R. 7829.1900, subp. 5 indicates that parties may file comments on suggested next steps after the Commission, by Order, requires an answer to the complaint.

The Nokomis Notice of Dispute and our response attached to the Complaint raises the issue as to how many other onsite DER systems does Nokomis (along with its subsidiaries) own or have pending applications for serving our customers in our exclusive service territory in Minnesota.

Under state law, Minn. Stat. §216B.40, we have the exclusive right to provide electric service at retail to each and every present and future customer in our assigned service territory and no other electric utility is allowed to provide this service. Under Minn. Stat. §216B.02, subd. 4, the definition of public utility:

> means persons, corporations, or other legal entities, their lessees, trustees, and receivers, now or hereafter operating, maintaining, or controlling in this state equipment or facilities for furnishing at retail natural, manufactured, or mixed gas or electric service to or for the public or engaged in the production and retail sale thereof...

This definition, however, excludes a "*person*" that produces or furnishes service to fewer than 25 persons. Subd. 3, defines "*person*" as including a corporation and two or more persons having a joint or common interest, which would include a parent corporation and all of its subsidiaries.

Accordingly, if Nokomis and its affiliates or subsidiaries are providing onsite service to 25 or more customers in Minnesota, including in our exclusive service territory, we believe it would be violating state law. To help us better understand the magnitude of Nokomis's onsite DER activity, as shown in the attachments to the Complaint, we asked Nokomis to provide us a list of each onsite DER system for which it provides electric service to our retail customers in Minnesota, including the address and size of the DER system and the name of our retail customer. Nokomis declined to provide this information.

Nokomis should be required to provide the information requested. This is the only way to ensure that any potential relief granted to Nokomis is not violating state law, in case Nokomis is providing electric service within the Company's exclusive service territory and would validate whether or not Nokomis is legally allowed to pursue its current interconnection application.

CONCLUSION

The Company has complied with the requirements established under MN DIP and our actions have not been arbitrary or discriminatory. We have also proposed constructive changes to MN DIP that could help address queue length and the Nokomis project and believe those changes are best addressed in Docket No. E999/CI-16-521.

We do not believe there are any reasonable grounds to further consider the Complaint nor is it in the public interest for the Commission to further investigate the issues raised in the Complaint. The Commission should compel Nokomis to provide Xcel Energy a list of each onsite DER system for which Nokomis provides electric service to our retail customers in Minnesota, including the address and size of the DER system and the name of each customer.

Dated: December 20, 2021

Northern States Power Company

Perspective Gained from Experiences of Duke Energy in the Carolinas, Oregon and New York Investor-Owned Utilities

Noteworthy perspective is gained by examining the DER interconnection experiences of Duke Energy Carolinas and the Investor-Owned Utilities (IOUs) in Oregon and New York.

a. Duke Energy

Duke Energy has two operating companies in the Carolinas: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, (collectively here, "Duke"). They jointly serve approximately 3.5 million customers in North Carolina and more than 4 million customers across North and South Carolina combined. This compares to Xcel Energy supplying electric service to about 1.3 million electric customers in Minnesota. Duke also uses a serial review and on hold process for DER interconnection, and experienced congested feeders and long queues, similar to the Company. These issues prompted the Duke Queue Reform, which is described in more detail in a series of filings to the North Carolina Utilities Commission.

In a September 3, 2020 filing noting a far-ranging interconnection Settlement of Duke with the "majority of the major utility-scale solar developers in North Carolina and South Carolina",[1] Duke noted that under its serial review interconnection process it had reviewed over 4,000 MW of distribution utility scale interconnection requests, of which over 2,000 MW resulted in successful interconnection, but over 1,000 MW were in queue and of these about 730 MW "*will be forced to sit idly in the interconnection queue for many years until earlier-queued Interconnection Customers commit to fund [Upgrades]*." (Pages 3-4). The large number of solar projects already interconnected had consumed substantial portions of capacity. More than 700 MW of projects were on-hold in the interconnection application process. (Page 9). Under Duke's serial review process, a later-queued project is not permitted to move forward in the interconnection process under the Upgrades assigned to the earlier-queued project are "*irrevocably paid for (i.e., there is certainty that such Upgrades will be paid for and thus the later-queued project can proceed assuming the construction of such Upgrades)*". (Pages 8-9). Duke entered into the Settlement, which among some other provisions implemented a cluster study process to help alleviate the long queue under the serial review process.

The North Carolina Utilities Commission recognized that the serial review process was not addressing the needs:

[1] Docket No. E-100, Sub 101, *Joint Notice of Interconnection Settlement and Petition for Limited Waiver*, September 3, 2020. See, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=fb20afad-cbc5-473b-8fc6-0c5a98227222

> ... the current serial approach to studying and processing Interconnection Requests has become problematic. In large parts of North Carolina it is not possible to add generation without the construction of expensive transmission upgrades. The current serial process assigns these upgrades to one generator, and the costs of these upgrades are typically too expensive for any one generator to absorb. The Commission agrees with parties who have stated that moving to a grouping study process is necessary in order to share the transmission upgrade costs among the multiple generation projects that contribute to the need for the transmission upgrades.[2]

These facts help to show that also the Duke serial review includes an on hold process, that long delays can be a common consequence of serial review on feeders with several applications, that Duke waits for "irrevocable" payment of DER interconnection costs before studying the next in queue, and that still Duke has been able to interconnect over 2,000 MW of DER. The Company in fact uses a less stringent approach of waiting for the signed interconnection agreement. Our approach is less stringent because a developer can still cancel the interconnection agreement after execution and would not be liable for the contemplated costs of interconnection in cases where the Company has not yet incurred any costs to modify our network to accommodate that interconnection.

We also note that while we have proposed a DER Technical Planning Limit, Duke has developed a "Method of Service Guidelines" that use a "planning capacity" limit for DER where the aggregate capacity of distribution-connected utility-scale projects (above 250 kW), per distribution circuit, shall not exceed the planning capacity of that circuit. Under Duke's planning capacity limit, aggregate capacity of distribution-connected utility-scale projects, per retail substation, cannot exceed the capacity of that substation, as defined by the (1) nameplate capacity of the substation transformer bank or (2) the capacity of other substation components, whichever is less. Also, the aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study. The aggregate DER capacity for further regulated zones (beyond any line voltage regulators (LVRs)) is limited to capacity that does not cause backfeed of the line voltage regulator.[3]

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[2] *See*, page 2 of the North Carolina Utilities Commission's October 15, 2020, Order in Docket No. E-100, Sub 101, available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=cba78a14-8db3-4d01-960f-9deac1dc6bec

[3] See, PDF page 6 of Duke *October 2017 DER Method of Service guidelines for DER no larger than 20 MW*, available at: https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-business/generate-your-own-renewable/method-of-service-guidelines-20171013.pdf=en&rev=b0a72550cc8b4aa9ad5eef6392f0eb28

Duke's DER planning capacity limit is noteworthy for its decision to limit DER interconnection from a circuit and geographic perspective. Duke's capacity limit does not allow generation backfeed across any field regulators present on their system. The functional purpose of field regulators is to adjust downstream voltage to stay within band and are therefore common on long rural feeders that may already encounter voltage concerns. Many of Xcel's large rural feeders such as CHI311, HUG321 and others have CSG's downstream of voltage regulators and if we were to have had a similar planning capacity limit a large number of currently installed CSGS would not have been allowed.

The North Carolina Utilities Commission in its October 14, 2020 order allowed limited waivers of its interconnection rules so as to allow the Settlement to be implemented.[4] The Settlement is complicated and nuanced, but here are some of its features that apply in certain situations:

A. Projects are subject to mandatory cluster studies.
B. The "Methods of Service Guidelines", which include the "planning capacity" limit for DER, apply.
C. Project must not require distribution line reconductoring greater than 0.5 miles as identified in the applicable System Impact Study.
D. Some DER transmission constrained projects were allowed to be interconnected without first having the Upgrades built to accommodate these projects in exchange for giving Duke the ability to curtail the output of these distribution projects as needed.
E. A limited set of projects would be studied and interconnected out of serial review order in specific situations where the interconnection of these projects in this way would most likely be technically and economically viable.
F. Certain projects in queue would be subject to an automatic reduction in nameplate capacity of 40 percent. Parties could then assign the remaining share to other projects in queue.
G. A limited pilot program was begun utilizing smart inverter functions.

b. Oregon

Beginning in the mid-2010s, Oregon's investor-owned utilities (IOUs) experienced sharp increases in interconnection applications for large, front-of-the-meter (FTM) solar projects on their distribution systems. The application growth was driven, in

[4] See, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=483506ff-3a54-4a75-abf0-b0ccf1504542

large part, by the standard compensation rates available for 15-year, fixed-price Qualifying Facility (QF) power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act (PURPA). The resultant small generator[5] interconnection volumes for Portland General Electric Company (PGE), the state's largest IOU,[6] are depicted in the table below:

Small Generator Interconnection Applications in PGE Company Territory[7]

Year	# of Small Generator Interconnection Applications	# of Small Generator Completed Interconnections
2014	3	1
2015	24	2
2016	33	0
2017	81	0
2018	80	Not reported in this format
2019	29	Not reported in this format
2020	13	26

Accompanying growth in the number of interconnection applications was growth in FTM capacity seeking interconnection. Between February 24, 2014, and July 28, 2017, there was a more than 90-fold increase in the capacity of solar QFs that had requested or executed PPAs in PGE territory, to a total of more than 1,000 MW of nameplate capacity by the latter date.[8]

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[5] Small generator interconnection applications in this instance cover FTM generating facilities up to 10 megawatts (MW) in nameplate capacity seeking to sell energy to the utility through a point of interconnection on the utility distribution system and that are neither part of the utility's community solar program nor under the jurisdiction of the Federal Energy Regulatory Commission. For more information, see PGE, *Distribution Interconnection Handbook*, November 4, 2021, https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Distribution_Interconnection_Handbook.pdf.
[6] PGE has approximately 900,000 total customers, while Pacific Power has approximately 600,000 total customers. There is a third, smaller IOU in Oregon, Idaho Power with approximately 20,0000 total customers. Customer counts are from Energy Information Administration (EIA), U.S. Department of Energy, *Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files*, 2020 data, release date October 7, 2021, https://www.eia.gov/electricity/data/eia861/
[7] PGE, *Division 82 Small Generator Interconnection Report* (May 27, 2021); PGE, *Division 82 Small Generator Interconnection Report* (May 29, 2020); PGE, *Division 82 Small Generator Interconnection Report* (May 30, 2019); PGE, *Division 82 Small Generator Interconnection Report* (May 30, 2018); PGE, *Division 82 Small Generator Interconnection Report* (May 31, 2017); PGE, *Division 82 Small Generator Interconnection Report* (May 31, 2016); PGE, *Division 82 Small Generator Interconnection Report* (May 29, 2015). These reports are filed *In the Matter of Portland General Electric Company, Annual Small Generator Interconnection Report as Required by OAR 860-082-0065*, Public Utility Commission of Oregon Docket No. RE 67. Filings in this docket are available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=17649
[8] PGE, *Supplemental Testimony and Exhibits of Brett Sims and Robert Macfarlane, Application to Lower the Standard Price and Standard Contract Eligibility Cap for Solar Qualifying Facilities (QFs)*, OPUC Docket No. UM 1854 (August 3, 2017), pp. 2-3, available at: https://edocs.puc.state.or.us/efdocs/HTB/um1854htb164929.pdf

The IOUs in Oregon use a serial review process. PGE small generator applications tend to be concentrated on a subset of the utilities' feeders. Similar to what has occurred in Xcel Energy Minnesota territory, the effects of the spike in interconnection volumes in Oregon have included complex, time-consuming engineering study processes for FTM applications as well as associated delays and complexities reviewing smaller behind-the-meter (BTM) solar interconnection applications at the same feeders[9] and periodic utility-customer disputes on study timing and cost outcomes.

In Oregon, two regulatory provisions have particularly helped address the interconnection backlog. First, the Public Utility Commission of Oregon (OPUC) decreased the maximum solar project capacity eligible for standard, 15-year fixed-price PPA compensation from 10 MW to 3 MW for Pacific Power and PGE in March 2016[10] and August 2017[11], respectively.[12] Second, on an annual basis, standard QF compensation rates are updated based on utility resource planning-based calculations to reflect then-current avoided costs under Commission-accepted utility resource planning methodologies. Levelized solar QF rates in PGE territory were

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[9] The interconnection impacts on behind-the-meter (BTM) projects were of sufficient concern to prompt PGE to propose and review with stakeholders, and the OPUC to accept, a temporary solution allowing as-needed curtailment of certain BTM DER. Doing so facilitated more interconnection of these DER in the near-term without requiring the interconnection customers to install expensive protective equipment that would otherwise be needed to maintain the safety and reliability of the distribution system. This temporary ("two-meter") solution "allow(s) PGE to use the second meter to perform temporary remote disconnection of the net metering project during periods of high generation and low customer demand on the feeder" and was implemented through changes to the utility's Agreement for Net Metering and Interconnection Services. See *In the Matter of Portland General Electric Company, Request for Approval of Agreement for Net Metering and Interconnection Services*, OPUC Docket No. UM 2099, Order No. 20-402 (November 5, 2020), Appendix A, page 1. As of July 2021, a total of "34 net metering customers … are required to utilize the two-meter solution on eight of the (utility's) Generation Limited Feeders." See *In the Matter of PGE's Request for Approval of Agreement for Net Metering and Interconnection Services*, Compliance Report, OPUC Docket No. UM 2099 (July 23, 2021), p. 1. Filings in this docket are available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=22427

[10] *In the Matter of PacifiCorp, dba Pacific Power, Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap*, OPUC Docket No. UM 1734, Order No. 16-130 (March 29, 2016). Filings in this docket available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=19559

[11] *In the Matter of Portland General Electric Company, Application to Lower the Standard Price and Standard Contract Eligibility Cap for Solar Qualifying Facilities*, OPUC Docket No. UM 1854, Order No. 17-310 (August 18, 2017). Filings in this docket available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20893

[12] As a result, most small generator applications are for solar projects of 2 to 3 MW_{AC} in nameplate capacity each. See PGE, OASIS, *Generation Interconnection, Oregon Small Generator Interconnection, Interconnection Queues, Small Generator Queue*, https://www.oasis.oati.com/pge/ (type "queue" in the search bar). In addition to the status report on small generator interconnection applications, there is a comparable report on community solar program (CSP) interconnection applications available from the same URL. There are currently far fewer CSP applications than small generator applications in PGE territory.

approximately $85/MWh in the first half of 2015[13] and have declined to approximately $40/MWh as of the second half of 2021.[14] Those decreases have corresponded with decreases in new, small generator interconnection applications as shown in the table above.

To complement these regulatory actions, the IOUs in Oregon have followed practices to improve interconnection performance across DER, such as enhanced pre-application reports, increased transparency, and customer education (e.g., posting more information about study processes and technical standards, application status, and congested feeders on their distribution systems), and more involvement with state regulatory staff in reviewing congested portions of utility distribution systems.[15] Xcel Energy has taken very similar steps to increase transparency and DER customer awareness.

Part of the approach in Oregon was that Community Solar interconnection applications were only allowed to be in the Community Solar queue if the capacity of the proposed Community Solar generator, together with all other interconnected and requested generation in the local areas, was less than 100 percent of the daytime minimum load (DML).[16] This aspect is unique to the Community Solar program, and is part of a broader program structure (that also includes a separate Community Solar queue) to limit siting and accelerate and simplify community solar project advancement through the interconnection process. This streamlined process reflects a proposal of the IOUs in Oregon that was accepted with some modification by the OPUC.[17]

Compared to the Xcel Energy proposed DER Technical Planning Limit, Oregon's DER capacity limit is significantly more conservative. If Xcel Energy were to use Oregon's DER capacity limit, then 144 of Xcel's feeders with high DER penetration

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[13] *In the Matter of Portland General Electric Company, Application to Update Schedule 201, Qualifying Facility Information*, OPUC Docket No. UM 1728, Order No. 15-206 (June 23, 2015), Appendix A at 3. Filings in this docket available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=19526

[14] *In the Matter of Portland General Electric Company, Updates to Schedule 201, Qualifying Facility Avoided Cost Information*, OPUC Docket No. UM 1728, Order No. 21-215 (July 6, 2021), Appendix A at 8. Filings in this docket available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=19526

[15] See, for example, *Staff Report, Community Solar Program Interconnection Solutions, Six Month Update*, OPUC Docket No. UM 1930 (July 20, 2020), pages 3-7. Available at: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau144450.pdf

[16] Id., page 4.

[17] *In the Matter of Public Utility Commission of Oregon, Community Solar Program Implementation*, OPUC Docket No. UM 1930, Order No. 19-392, November 8, 2019, Appendix A at 6-7, available at: https://apps.puc.state.or.us/orders/2019ords/19-392.pdf , and *In the Matter of Public Utility Commission of Oregon, Community Solar Program Implementation*, OPUC Docket No. UM 1930, Order No. 20-038, February 4, 2020, Appendix A at 4, available at: https://apps.puc.state.or.us/orders/2020ords/20-038.pdf .

have already exceeded their feeders' DML with many exceeding DML several times over.

c. New York

Five IOUs[18] in Upstate New York "experienced an unprecedented surge in (interconnection) applications for projects sized between 50 kW and 2 MW" between October 2015 and April 2016, which corresponded to the opening of the community distributed generation (CDG) market in the state.[19,20] The influx was the main reason that more than 1,700 solar projects between 1 MW and 2 MW were in the interconnection queue across these five utilities as of December 2016.[21]

The volume of CDG applications in the interconnection queues led to significant delays and uncertainties as to timing and cost outcomes from the utilities' interconnection reviews and studies.[22] Those issues affected not only the CDG applications, but also smaller net metering interconnection applications at many utility feeders. Among the interconnection challenges was that "without a mechanism allowing the Utilities to clear inactive projects, many applicants were slow to progress, while many others did not take any steps beyond the initial application stage."[23]

To address these interconnection challenges, the IOUs[24] working collaboratively with numerous solar industry representatives through the state Interconnection Policy Working Group identified compromise solutions and, then, formally petitioned the NYPSC on September 30, 2016, to consider regulatory implementation of the solutions.[25] The NYPSC approved the petition, with some modifications, in a January

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[18] These five utilities are Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation dba National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
[19] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, State of New York Public Service Commission (NYPSC), Case No. 16-E-0560 (January 25, 2017), p. 20.
[20] Individual CDG applications, which tend to be FTM solar projects, were capped at 2 MW in capacity.
[21] Moaveni, Houtan, New York State Interconnection Ombudsman and Deputy Director of NY-Sun, New York State Energy Research and Development Authority, *NY-Sun Overview*, p. 13, https://hudsonvalleyregionalcouncil.org/wp-content/uploads/2019/08/NY-Sun-Overview.pdf.
[22] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, NYPSC, Case No. 16-E-0560 (January 25, 2017), p. 20.
[23] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, NYPSC, Case No. 16-E-0560 (January 25, 2017), p. 20.
[24] In addition to the five Upstate New York IOUs listed above that were most affected by CDG applications, the sixth New York IOU (Consolidated Edison Company of New York, Inc., which is based downstate) was involved in all pertinent IPWG efforts.
[25] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, NYPSC, Case No. 16-E-0560 (January 25, 2017), p. 1.

25, 2017, Order.[26] This resolution was complicated and addressed New York specific concerns. The resolution included allowing the utilities to remove from the queue those projects that fail to meet the interconnection process deadlines.[27] Other aspects of the Order to improve the interconnection process included: a limited, interim cost sharing approach; a mechanism for applications to receive extensions if local solar permitting moratoria are in place; and enhanced requirements for applicants to demonstrate site control.[28]

[26] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, NYPSC, Case No. 16-E-0560 (January 25, 2017), pp. 35-36.
[27] NYPSC, *New Rules Help Add More Community Solar Projects to the Electric Grid, Boosting Clean Power in New York*, January 24, 2017, https://apps.cio.ny.gov/apps/mediaContact/public/view.cfm?parm=36F0F0AC-AC6F-A17E-DF283529D2621137.
[28] *Order Adopting Interconnection Management Plan and Cost Allocation Mechanism, and Making Other Findings*, NYPSC, Case No. 16-E-0560 (January 25, 2017), pp. 24-26, 28-30, 31.

Overview of MN DIP Timelines Leading up to Interconnection Agreement

Initial Engineering Screen	MN DIP 3.2	15 Business Days
Customer Options Meeting	MN DIP 3.3	10 Business Days
Supplemental Review - payment	MN DIP 3.4.1	15 Business Days
Supplemental Review screens	MN DIP 3.4.4	37 Business Days
Supplemental Review decision for Study	MN DIP 3.4.6	15 Business Days
Scoping Meeting	MN DIP 4.2	10 Business Days
System Impact Study issued	MN DIP 4.3.2	5 Business Days
System Impact Study payment	MN DIP 4.3.4	20 Business Days
System Impact Study completed	MN DIP 4.3.5	30 Business Days
System Impact Study results provided	MN DIP 4.3.5	5 Business Days
Facilities Study Agreement issued	MN DIP 4.3.5	5 Business Days
Facilities Study Agreement payment	MN DIP 4.4.3	15 Business Days
Facilities Study completed	MN DIP 4.4.6	45 Business Days
Facilities Study comments on draft	MN DIP 4.4.10	20 Business Days
Facilities Study final version	MN DIP 4.4.11	15 Business Days
MN DIA issued	MN DIP 5.1.1	5 Business Days
MN DIA signed by customer	MN DIP 5.1.2	30 Business Days
MN DIA countersigned	MN DIP 5.1.2	5 Business Days
Total		302 Business Days

Chronology of Discussion of
Serial Review and Multiple Applications in Same Queue
from Docket No. 16-521 in developing the MN DIP

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
Joint Movants (ELPC/Fresh Energy/IREC) initial proposal – filed May 12, 2016 in Docket 01-1023, and also filed **June 16, 2016** in Docket 16-521	1.8 Queue Position The Area EPS Operator shall assign a Queue Position based upon the date- and timestamp of the Interconnection Application. The Queue Position of each Interconnection Application will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Area EPS Operator shall maintain a single queue. At the Area EPS Operator's option, Interconnection Applications may be studied serially or in clusters for the purpose of the system impact study.	Original proposed language made it clear that the choice of the Area EPS Operator to either study serially or have clusters for purpose of System Impact Study.
IREC comments included in notes from **June 2, 2017** Workgroup Meeting #2, filed 9/29/17	PDF Page 36: In particular, I will note that there is a need to discuss whether the rules should address how utilities will manage the queue, particularly for smaller projects that may apply after a larger project but pass through the technical screens faster.	Recognizes that those later in queue, even small projects, may be delayed due to management of the queue, where there are larger projects ahead in queue.
Minnesota Distributed Generation Workgroup Meeting #4 Packet Contents for **September 15, 2017**, filed 9/29/17	PDF Page 19: Data Reporting- Expedited interconnection process is extremely valuable for developers and customers. Some participants suggested annual data reporting or detailed queue transparency/reporting that includes timelines (start and finish) and possibly additional data that could help with continuing to improve the process by understanding where the problems or backlogs occur which may be developer, utility or policy driven.	Recognizes that problems or backlogs can occur, and these may be policy driven. Recognized that detailed queue transparency would help to improve the process by understanding the problems.
Summary for meeting of **September 15, 2017**, filed 12/14/17	PDF Page 3: Topics flagged for possible additional DGWG In-Person Discussion: 1) Queue 1. Joint Movants' proposal on interconnection queue data and reporting 2. How check in/communication works for the second and beyond in queue PDF Page 8: The publication of the queue position and reporting was part of the package on the process timeline proposal the Joint Movants made valuing transparency/information over	Recognizes that there are issues for second and beyond in queue, and communication is important in this situation. The publication of the queue was part of the package on the timeline proposal, recognizing that utilities would not be

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
	penalizing utilities on deadlines; whereas, the customer faces a large penalty (lost queue position for missing deadlines.) PDF Page 49 (Xcel written responses on certain issues): For example, for a feeder that has reached 98% of its hosting capacity, a 5 kW rooftop system may start to become significant.	penalized on deadlines. Even a small project can be delayed where the feeder is near hosting capacity.
Xcel Energy Supplemental Comments, **11/2/17**, pages 19-20	Sequential processing is needed due to the level of rework associated with simultaneous processing that makes assumptions of project decisions. For example, in the Company's Solar* Rewards Community program, the tariff states that all studies needed to result in an Interconnection Agreement within 50 business days. This led to processing entire substation queues in that time period by making assumptions that projects earlier in queue would decide to pay for system upgrades to achieve full project capacity. However, a large number of developers chose to interconnect a lesser amount than was originally applied for, which resulted in a large number of restudies, slowing down the overall queue processing. Some projects later in queue were restudied multiple times due to this process. For these reasons, the Company sees sequential processing of applications as the most efficient method. This would require later in queue project to wait until earlier in queue projects either sign an Interconnection Agreement or run out of time before proceeding with the technical review.	Shows need for sequential review under MN DIP. Uses sequentially interchangeable with serially.
OTP Supplemental Comments, **11/ 2/ 2017**	How should the standards address the timing of multiple applications studies at the same time on the same part of the system (e.g. feeder or substation) and the impact, if any, on timelines? Is there data on this issue that can inform the decision? Otter Tail sees two approaches to this issue. The first is that we perform the studies in the time specified within the interconnection process timelines. Under this scenario, any study results would be contingent on all prior queue generators coming on line. The other option is to place the later requests on hold until the earlier queued projects are processed. Otter Tail is indifferent to the approach, but would like the Commission to clearly documented how later queued interconnection should be handled to avoid any confusion.	OTP recommended that applications be place on-hold, or make all study results contingent on all prior in queue projects coming on line.
Wind on the Wires (WOW), Supplemental Comments **11/2/17**	Pages 2-3: … timely processing of interconnection requests all depend on a party's position in the queue, which is why record of these positions is important to be maintained and honored through a queue. … Typically, interconnection requests will be processed sequentially in queue order. Larger utilities and transmission providers with significant numbers of interconnection requests in the same areas are beginning to process interconnection requests in clusters rather than serially.	Recognizes that the timing for processing an application depends on queue position. This is why the public queue is important. Also, recognizes that interconnection requests will be processed

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
		sequentially in queue order. Uses terms “serially” and “sequentially” interchangeably as reflected in workgroup discussions.
Joint Movants Supplement Comments, **11/ 2/ 17**	Pages 12-14: One challenge of queued applications that was not discussed during the working group is how an applicant that is not first in the study queue and on the same part of the system as an earlier, but not yet complete, application is handled.33 The Joint Movants recommend that an applicant that is not first in queue be given the option to either (a) wait until the study or studies in front of it in queue are completed, while maintaining its queue position, or (b) proceed with a study as if the project(s) ahead are existing while accepting the responsibilities of the cost and added time of restudying the project should the earlier projects change or withdraw. Providing the applicant the option to maintain its queue position while hitting the “pause button” on timelines and study costs may be the best option for an applicant where the timing of the project completion is not urgent, or if the economics of the projects hinge on the construction or withdrawal of the earlier applicant. On the other hand, developers pushing to meet a deadline for construction, or those confident about the viability of their projects regardless of the earlier applicant, may wish to move forward. [IREC then proposed specific redline edits to MN DIP 1.8 aligned with their proposal to give customers the option to wait to be studied until those ahead in queue have executed Interconnection Agreements.]	Joint Movants recommended that applicants be given the choice of either waiting for ahead in queue projects to have executed Interconnection Agreements, or proceed with the understanding that there could be added time and costs associated with projects ahead in queue withdrawing.
Joint Movants Reply Comments, **11/ 15/ 17**	Page 5: [Under MN DIP] a project that entered the queue on an earlier date and is on a circuit with multiple projects ahead of it may have to wait longer to interconnect than a project that entered the queue on a later date and is first in line to interconnect to a different circuit.	Joint Movants recognized that later in queue projects need to wait for ahead in queue projects.
Wind on the Wires (WOW), Reply Comments **11/15/17**	Pages 14-16: We want to express support for the Joint Movants proposal to allow an IC to decide if they would prefer to wait until earlier interconnection requests are processed, or to be processed at the same time, with both studies moving forward simultaneously. ... We do however want to highlight one challenge with this option if there are multiple electrically related requests in an area, and we offer one suggested addition, which can help address this challenge. The one concern we have with the Joint Movants’ proposal is the situation where one IC may choose to wait, or “pause”, until an earlier IC in an area finishes its study	Notes WOW agreement with Joint Movants proposal of 11/2/17, but also notes deficiency in that proposal.

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
	process, but at the same time there are additional parties behind the "paused" party who do not want to delay their interconnection studies. The question arises of how to maintain the rights of parties in queue order, but also avoid long delays for later parties. Given that this situation has not become a regular occurrence in Minnesota, WOW believes that the Joint Movants' proposal for IC choice is the best step forward at this point, with one addition. We suggest that if more than three interconnection requests in an area appear to be electrically related, the utility will communicate with these interconnection customers to discuss a cluster study. If a party has chosen to "pause", and a group of ICs agrees that a cluster study is in their best interests, this cluster study could proceed after the first in queue study is completed, and the waiting party is "unpaused". We offer the modified language below to include this requirement.	
Xcel Energy, Reply Comments **11/15/17**	Pages 4-5: The interconnection standards should state that sequential queue processing is the uniform statewide practice. The Joint Movants proposed offering either sequential or simultaneous study methods to the customers for each project. A sequential method would wait for a level of certainty on prior projects moving forward before proceeding with subsequent studies, while the simultaneous method would make assumptions on decisions for prior in queue projects and proceed with studies accordingly. Setting aside for a moment fundamental efficiency issues with simultaneous studies, a situation where neighboring queues are processed using different methods could lead to an inconsistent experience that may be confusing for customers. This type of process would certainly be more challenging for utilities to track and administer. As the Company pointed out in the November 2, 2017 Comments, experience has shown simultaneous processing leads to significant inefficiencies. Furthermore, later in queue projects cannot be offered an Interconnection Agreement until previous in queue projects sign the Interconnection Agreement, which means the path to construction is still dependent on actions made regarding projects earlier in queue. A related improvement that the Joint Movants offered to the MIP is to define customer decision timeframes, which reduces the likelihood of queue processing being halted during customer process steps and is an enhancement compared to the Company's Solar*Rewards Community program rules. Project withdrawals or significant size reductions trigger new studies, which increases the overall workload and potentially lengthens timeframes for the queue portfolio. It is expected that Customers would choose the simultaneous study path under conditions of high volume, which would slow down queue processing at a time when all available	Interchangeably uses sequential review to mean serial review. Serial review needs to wait for Interconnection Agreements to be issued for projects ahead in queue. Points out problems with using simultaneous review.

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
	utility resources are needed to meet the required timeframes. In reviewing other state rules, the Company has found no indication that the Joint Movants' queue processing proposal has been implemented elsewhere. As a matter of both practical queue administration and queue efficiency, the Company opposes introducing this new concept into the Minnesota interconnection standards.	
Wind on the Wires (WOW) Initial Comments on Draft Staff Recommendations, **3/29/18**	Pages 4-5: Typically, interconnection requests will be processed sequentially in queue order.	Similar to WOW comments of 11/2/17. Uses sequentially interchangeable with serially. Recognizes that this is the typical process.
Staff Briefing Papers for **5/24/18**	Page 68 has the following redline changes to the then current draft of the MN DIP (ver.2.1): 1.8.3 The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.) This administrative queue shall be reported annually and be used to address Interconnection Customer inquiries about the queue process. At the Area EPS Operator's option, Interconnection Applications may be studied serially or in clusters for the purpose of the system impact study.If the Area EPS Operator and the Interconnection Customer(s) agree, Interconnection Applications may be studied in clusters for the purpose of the system impact study; otherwise, they will be studied serially. The annual reporting form can be found on the Department of Commerce's website:	See row below.
Staff Briefing Papers for **5/24/18**	Page 178 explains the Staff rationale and DGWG considerations for above changes to 1.8.3: Flexibility in queue processing for the Area EPS, but preserves the Interconnection Customer's queue position and ability to get information about the process. Annual reporting of the administrative queue allows the Commission or the DGWG process to evaluate how the newly updated statewide standards are working. Utilities requested flexibility in management and details provided in the queue, and argued against administrative burden with limited value. Interconnection customer advocates argued information about the queue was important both for the individual customer to have a sense of the progress of their application, and to evaluate the effectiveness of the statewide interconnection standards. DGWG Mtg #2	Edits by Staff recognize tradeoff with public reporting of queue, queue position established conditional interconnection capacity, and allows for serial processing/studying of interconnection applications except where parties agree to cluster study for the system impact study. Gives utilities the requested flexibility in management and details in the queue.

Filing	Excerpt [or high level summary if in brackets]	Comment on Excerpt
Staff Briefing Papers for **5/24/18**	1.8.3 The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.) This administrative queue shall be used to address Interconnection Customer inquiries about the queue process. If the Area EPS Operator and the Interconnection Customer(s) agree, Interconnection Applications may be studied in clusters for the purpose of the system impact study; otherwise, they will be studied serially.	Consistent with above row.
MPUC order **8/18/18**	Adopted 1.8.3 as suggested by Staff: 1.8.3 The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.) This administrative queue shall be used to address Interconnection Customer inquiries about the queue process. If the Area EPS Operator and the Interconnection Customer(s) agree, Interconnection Applications may be studied in clusters for the purpose of the system impact study; otherwise, they will be studied serially.	Appears to adopt the reasoning of Staff.

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process described above, or will be studied as part of the cluster study being conducted under the IOU's WDATs.[142]

The one-study process in place in many states and the two-study process recently adopted in California suggest that a full three-study process may not be necessary, particularly for small generators. In particular, the role of the Feasibility Study is fairly limited since much of the crucial detail of interest to generators, particularly regarding cost, does not come until the later studies.

The changes adopted in California do not necessarily shorten the overall study process, since the duration of each study is greater than that provided for in SGIP.[143] However, it is worth considering whether the times required for the System Impact Study and Facility Study can be kept the same in SGIP, or only modestly increased, even if the Feasibility Study is eliminated.

Possible Modification: Moving from Serial Study to Group/Cluster Study

As discussed above, the SGIP uses a serial study process for determining interconnection requirements for a particular generator.[144] Under a serial study approach, interconnection requests are studied one at a time, on a first-come, first-served basis. The order of requests received is made publicly available through posted interconnection queues.[145] Under this approach, an interconnection request may not be studied until all queued-ahead generators have been studied. The reason is two-fold. First, the amount of utility resources that can be devoted to the processing of interconnection requests may be limited. If utility resources are limited, it may be necessary to complete the study of generators further ahead in line to free up resources to study later-queued interconnection requests.

A second factor is the necessity to complete the interconnection of queued-ahead generators to determine the anticipated system configuration for the study of later-queued generators. This is an important consideration, because upgrades that may be required to interconnect a generator that is ahead in the queue may facilitate the interconnection of generators further behind in the queue. On the other hand, if a generator earlier in the queue decides not to move forward with its interconnection, and therefore upgrades that would have been completed to accommodate that generator are not completed, the study of later-queued generators would not assume the existence of those upgrades. The result is that a generator further back in the queue may be responsible for the completion of the upgrades that would have otherwise been completed to facilitate the interconnection of the queued-ahead generator, if it had gone forward.

There may also be a need to re-study the later interconnection requests. A high number of speculative projects in an interconnection queue that drop out during or after the study process can result in a ripple effect that can impact and necessitate restudy of applicants further back in the interconnection queue. This lengthens the serial study process and increases costs. In sum, the requirements for a generator further back in the queue may not be able to be determined until the status of all generators that are ahead in line have been determined.

The serial study process may work well in situations where a utility is a) processing a low volume of interconnection applications such that existing resources are sufficient to timely handle the volume of interconnection requests being received, and b) generators seeking interconnection are sufficiently independent such that the ability to move forward with studies is not significantly delayed by the need to process earlier interconnection requests to determine the base case for generators farther back in the queue. The serial study process becomes less efficient when the volume of interconnection requests and interrelatedness of interconnection requests reaches a point where significant delays in processing interconnection requests results. Under these conditions, the serial study process can lead to long delays, and other options may need to be explored.[146]

When a utility begins to receive sufficiently high volumes of interconnection requests, and high penetrations are reached such that multiple interconnection requests may impose impacts on the same area of an electric power system, a group or cluster study process may be more efficient. ISOs and individual utilities in the United States have identified some of the possible benefits of studying interconnection requests in groups or clusters and have adopted changes to implement these procedures. FERC recently approved modifications to the Open Access Transmission Tariffs for CAISO, MISO and PJM that reflect a move toward group studies.[147] Two of the California IOU's followed CAISO's lead and adopted a cluster study process for interconnection requests interrelated with the transmission system.[148] Finally, the CPUC is considering adopting a group study process for distribution-level interconnections under Rule 21.[149]

There are a number of advantages to a group study approach. First, a group study process may make more efficient use of limited utility resources by enabling multiple studies to be combined. Second, a group study process may allow interconnection applications to be processed more quickly. Studying a group of projects at once eliminates the need for later queued projects to wait in line. Finally, a group study process may allow for a beneficial sharing of costs across generators, both for study and for upgrades that may be necessary to accommodate the interconnection of multiple generators. Imposing the full cost of upgrades—which may facilitate the interconnection of multiple generators—on the first generator that triggers the upgrades may pose a barrier to market growth. By studying generators together, the costs of upgrades can be spread equitably across the generators that may ultimately benefit.

There may also be negatives to the group study approach. First, the transmission cluster study process in California takes nearly two years to complete. Thus, while it may place a lower burden on utility resources, it also may require more time overall.[150] However, in California the serial study queues were so clogged that there was an expectation that it could take many years to complete the process.[151] Second, where a location has a high number of speculative projects in its interconnection queue, utilities may need to develop a method of sorting out how many total combined MW to realistically study and how to estimate and assign the cost of upgrades. Assuming that only a percentage of interconnection requests will actually move forward, studying the full number of proposals could result in inflated estimates of the amount of upgrades actually required.

An important consideration in a group study process is which interconnection requests to study together. The answer should generally depend on which interconnection requests pose interrelatedness considerations. Projects that are transmission dependent likely need to be studied with other transmission-dependent projects. However, projects that do not interact with the transmission system could be studied in smaller groups with only the other projects they interact with on the distribution system.

The group study approaches being implemented across the United States appear to offer significant promise for dealing with high volume and high penetration situations at the distribution level. Each region has taken a slightly different approach to the issue at this stage and further information is needed on what the pros and cons are of each approach. This is a possible area for improvement of SGIP that warrants further consideration.

4. RECOMMENDATIONS

This section recaps and summarizes the recommendations provided in Section 3:

- Update federal and state interconnection procedures to meet the demands of a growing national marketplace for solar PV and other small renewable generators interconnecting to electric power distribution systems.
- Incorporate a pre-application report through which an interconnection applicant can request information about specific, relevant technical conditions at a proposed point of interconnection.
- Extend the 10 kW Inverter Process to generators up to 25 kW.
- Shorten the time for determining a 10 kW Inverter Process application is complete to 3 business days after receipt.
- Consider automatic approval of 10 kW Inverter Process applications after an identified timeframe unless an applicant is notified otherwise by a utility.
- Allow for online submission of interconnection applications.
- Allow for electronic signatures to be provided on interconnection applications.
- Consider modifying Fast Track eligibility to take into account system conditions at the point of interconnection. A proposed approach is provided in Table 2.
- Allow generators up to 25 kW to skip the short circuit duty screen (SGIP Screen 5).
- Modify the line configuration screen (SGIP Screen 6) in two ways: allow generators less than 11 kVA to skip the screen; and allow generators below 10% of the line section's peak load to pass the screen regardless of line configuration.
- Modify the transient stability screen (SGIP Screen 9) in a manner that examines whether a generator has dependencies with other generators yet to be studied on the transmission system.
- Replace the no construction screen (SGIP Screen 10) with a process that provides a utility increased time to estimate costs for necessary construction as potential construction becomes more complex.
- Allow a customer to opt into a Facilities Study (either after Initial Review or Supplemental Review) to determine the likely cost of upgrades prior to

114 SGIP §§ 2.3.1 (providing changing meters, fuses, or relay settings as examples of minor modifications), 2.4.1.2, 2.4.1.3.

115 *See, e.g.* DSIRE, State Interconnection Pages: Illinois, Colorado, and North Carolina; *but see* Indiana and South Dakota, *supra*, note 45.

116 *See, e.g.* DSIRE, State Interconnection Pages: New Mexico, Massachusetts, and Nevada, *supra*, note 45.

117 *See* SCE and PG&E queue data, *supra*, note 69.

118 SCE WDAT § 6.5.10; *see also So. Cal. Edison Co.,* 135 FERC ¶ 61,093, at P 94.

119 PG&E WDT § 2.3.3; *see also Pacific Gas & Electric Co.*, 135 FERC ¶ 61,094, at P 65.

120 PG&E WDT § 2.4.1.1.

121 PG&E WDT § 2.3.4.

122 SGIP § 2.3.2.

123 Hawaii Rule 14H, Sheet No. 34D-16.

124 Hawaii Rule 14H, Appendix III, 3(d).

125 "Hawaiian Electric companies ease pay to solar electric power", Hawaiian Electric Company News Release, September 18, 2012, *available at*: http://www.heco.com/vcmcontent/StaticFiles/pdf/20120918-easier2addsolar2roofs.pdf.

126 Hawaii Rule 14H, Appendix III, 3(d).

127 Hawaii Rule 14H, Sheet No. 34B-9 – 12.

128 Rule 21 G.2, Screen N, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

129 Rule 21 G.2, Screen O, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

130 Rule 21 G.2, Screen P, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

131 SGIP § 3.3; SGIP Attachment 6.

132 SGIP § 3.4; SGIP Attachment 7.

133 SGIP § 3.4.2.

134 SGIP § 3.5; SGIP Attachment 8; FERC Order 2006 at P 44.

135 SGIP § 3.2.2.

136 SGIP § 3.3.4; 3.4.5.

137 CAISO Tariff § 6.4.

138 CAISO Tariff § 7.1.

139 CAISO Tariff § 4.0.

140 CAISO Tariff § 4.4.4; SCE WDAT § 5.8.1.2. PG&E provides for 60 *business days,* which is roughly similar to 90 calendar days. PG&E WDAT Attachment 7, § 7.0 & 9.0.

141 CAISO Tariff § 4.5.3; SCE WDAT § 5.8.2.3. PG&E provides 60 business days where upgrades are required and 45 business days where only interconnection facilities must be studied. PG&E WDAT Attachment 8, § 7.0.

142 Rule 21 E.2.b, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

143 Though it should be noted that in California the utilities were rarely able to keep the time allocated for each study due to the increasing volume of requests they were reviewing. This may be the case in other high volume states.

144 SGIP § 1.6.

[145] *See, e.g.,* www.oatioasis.com/FPC/FPCdocs/GIS_Queue_Table_061212.mht (Florida Power Corporation generator queue); www.oatioasis.com/DUK/DUKdocs/genqueuedetails.pdf (Duke Energy Carolinas generator queue).

[146] *See, e.g., Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[A]s more projects enter the queue, a study backlog develops and becomes increasingly large as more projects enter the queue, because subsequent projects must wait for the results of the studies of any electrically related earlier queued projects to be studied."); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011) ("SCE similarly estimates that it would take as long as six to seven years to complete the studies for all of the Small Generators currently in the SCE queue."); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Because each project has its own separate timeline, a study for one project can not be undertaken until the studies for previous, electrically-related projects are completed. As additional small generator interconnection requests enter the queue, a study backlog develops and becomes increasing large.").

[147] *See, e.g., PJM Interconnection, L.L.C.*, Docket No. ER12-1177-000, 139 FERC ¶ 61,079 (2012); *Cal. Independent System Operator Corp.,* Docket No. ER11-1830-000, 133 FERC ¶ 61,223 (2010); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER08-1169-000, 124 FERC ¶ 61,183 (2008). The approved tariffs are *available at* www.pjm.com/~/media/documents/manuals/m14a.ashx (PJM Manual 14A); www.caiso.com/Documents/AppendixY_2012-04-18.pdf (CAISO Appendix Y); https://www.midwestiso.org/_layouts/MISO/ECM/Download.aspx?ID=19304 (MISO Attachment X).

[148] *See, e.g., So. Cal. Edison Co.*, 135 F.E.R.C. ¶ 61,093 (2011); *Pacific Gas & Elec. Co.*, 135 F.E.R.C. ¶ 61,094 (2011). The approved tariffs are *available at* http://asset.sce.com/Documents/About%20SCE/WholesaleDistributionAccessTariffv3.pdf (SCE Attachment G); www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf (PG&E Attachment I).

[149] *See* Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations, CPUC Docket R.11-09-011, p.7 (March 16, 2012) (recommending that the CPUC consider distribution group studies as part of Phase II of the rulemaking in Docket No. R.11-09-011), *available at* http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF.

[150] *See* Interstate Renewable Energy Council's Motion to Intervene in FERC Docket No. ER11-3004-000, Attachment G: Cluster Timeline (slide from January 25, 2011 presentation on "Redefined PG&E WDT Generation Interconnection Proposal: Generation Interconnection Procedures") (March 23, 2011), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594944.

[151] *See So. Cal. Edison Co.,* 135 FERC ¶ 61,093 at P 28.

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11/17/2021

Minnesota Distributed Energy Resources Interconnection Process (MN DIP)
Supplemental Review Results

Customer: [redacted]
Case # 4498403
Address: [redacted]
DER Application Size: [redacted]

Interconnection Feeder:	NOF071	Substation:	Northfield
DER Active on Feeder:	6,046.98 kW	DER Active on Substation:	6,099.19 kW
DER in Queue on Feeder:	5,004.89 kW	DER in Queue on Substation:	6,009.53 kW

Summary of Results:
This project has failed both the Initial Review and the Supplemental Review Screens, the details of which can be found below. To determine if the project can be interconnected consistent with safety, reliability, and power quality standards, the project will need to enter the Study Process. The Interconnection Customer will be provided with the opportunity to attend a customer options meeting.

Ground Referencing Adequacy
Based on the project size and system configuration, the ground referencing equipment specifications appear to be adequate for installation with this interconnection. Should the size or configuration of this project change at any point in time, this determination will no longer be valid. It is the customer's responsibility to ensure that the ground referencing equipment specifications are reviewed and in compliance with Xcel Energy's Ground Reference Requirements.

Supplemental Review Screens

3.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

Voltage Regulation
Does the screen indicate a high probability of compliance with ANSI C84.1 Range A for steady state voltage regulation on Xcel Energy's electric distribution primary (medium-voltage) system? [redacted]

Does the screen indicate a high probability of compliance with ANSI C84.1 Range A for steady state voltage regulation on Xcel Energy's electric distribution secondary (low-voltage) system? [redacted]

Voltage Fluctuation

Does the screen indicate a high likelihood of compliance with IEEE 1453 for voltage fluctuation at any point on Xcel Energy's electric distribution system? [redacted]

3.4.4.3 Safety and Reliability:

Conductor Loading

The line section from the substation to the Point of Common Coupling is rated for the current produced by the DER.

Approximate maximum conductor loading as a percentage of rated ampacity when DER is on: [redacted] %

Passes Screen? [redacted]

Substation Transformer Loading

Substation Transformer Rating:	[redacted]	kVA
Aggregate DER on Substation:	13,108.72	kVA
Peak Load (Native):	[redacted]	kVA
Substation Transformer Rating Exceeded by:	[redacted]	kVA
Screen Passes?	[redacted]	

Protection Coordination

Is a study required to verify Protection Coordination? [redacted]

Passes Screen? [redacted]

Direct Transfer Trip

Is there existing rotating machine DER on the Substation Transformer? [redacted]

Is there existing rotating machine DER on the Feeder? [redacted]

Is a System Impact Study required to determine if Direct Transfer Trip is required? [redacted]

Passes Screen? [redacted]

Transmission Impacts

Is a study required to verify Transmission System Impacts [redacted]

Passes Screen? [redacted]

3.4.5.2 Facilities Construction

Voltage Supervisory Reclosing (VSR)

If the load to DER ratio is ≤ 1.25, VSR is required on reclosing devices. If this DER project causes the threshold to be exceeded, it will be responsible for installing VSR.

Daytime Minimum Load(Native):	[redacted]	kVA
Aggregate DER on Feeder:	12,052	kVA
Load to Generation Ratio:	[redacted]	
New DER causes VSR threshold to be exceeded?:		
Is VSR required to be installed as a result of this DER?:		

Reverse Power Flow Controls

If the feeder experiences reverse power flow, regulating devices may need to be upgraded or replaced. If this DER project is the cause of the reverse power flow, it will be responsible for these upgrades/replacements.

Reverse Power Flow on Feeder:	[redacted]	kW
New DER causes reverse power flow?:		kW
Is this project responsible for upgrading regulation devices that need to be capable of reverse flow?		

Primary Conductor Construction

Construction of Primary Conductor may be required to convert a single-phase line to a three-phase line to the PCC.

Is a three phase primary conductor extension required?	[redacted]	
Approximate footage of extension:		ft

Service Conductor Upgrades

Service Conductor Upgrades may be required due to loading, voltage fluctuation violations, or steady state voltage violations.

Is a service conductor upgrade required?	[redacted]	
Approximate footage of upgrade:		ft

Existing conductor type(s) to be replaced:	
New conductor type(s):	

Other Construction of Facilities

Construction of other facilities may be required to interconnect the DER.
They are listed below.

Are construction of other facilities required? [redacted]

Description of facilities:

Ground Referencing

Inverter-Based Systems 100 kW or greater require ground referencing. The adequacy of the provided ground referencing specifications are evaluated below.

Requirement 1:	$X_{0, DER}$=	[redacted]	p.u.
	As Specified: $X_{0, DER}$=		p.u.
	Requirement Met?		
Requirement 2:	$X_{0, DER}/R_{0, DER} \geq$	[redacted]	
	As Specified: $X_{0, DER}/R_{0, DER} \geq$		
	Requirement Met?		
Requirement 3:	Neutral Current Rating for V_0 = 4%=	[redacted]	amps
	Neutral Current Rating, as specified=		amps
	Requirement Met?		
Requirement 4:	Required fault current withstand rating=	[redacted]	amps
	As Specified=		amps
	Requirement Met?		

CERTIFICATE OF SERVICE

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

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

xx by electronic filing.

Docket No.: E002/C-21-786

Dated this 20th day of December 2021.

/s/

____

Crystal Syvertsen
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-786_C-21-786
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-786_C-21-786
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-786_C-21-786
Matthew	Melewski	matthew@nokomisenergy.com	Nokomis Energy LLC & Ole Solar LLC	2639 Nicollet Ave Ste 200 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_21-786_C-21-786
Matthew	Melewski	matthew@theboutiquefirm.com	The Boutique Firm PLC	5115 Excelsior Blvd #431 St Louis Park, MN 55416	Electronic Service	No	OFF_SL_21-786_C-21-786
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-786_C-21-786
Daniel	Rogers	dan@nokomispartners.com	Nokomis	2639 Nicollet Ave Ste 200 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_21-786_C-21-786
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-786_C-21-786
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Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_21-786_C-21-786