Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

April 17, 2025

—Via Electronic Filing—

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

RE: REPLY COMMENTS
IN THE MATTER OF UPDATING THE GENERIC STANDARDS FOR THE INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. §216B.1611
DOCKET NO. E999/CI-16-521

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments consistent with the schedule in the February 10, 2025, Notice of Comment Period (Notice).

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 Kristen Ruud at Kristen.S.Ruud@xcelenergy.com or 612-216-7979 if you have any questions concerning this filing.

Sincerely,

/s/

JESSICA PETERSON
MANAGER, PROGRAM POLICY

Enclosures
cc: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF UPDATING THE GENERIC STANDARDS FOR THE INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. §216B.1611	DOCKET NO. E999/CI-16-521 **REPLY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments in response to the April 3, 2025 Initial Comments filed by the Minnesota Department of Commerce, Clean Energy Organizations (CEO), and the Joint Parties. The CEO consists of Clean Energy Economy MN (CEEM), the Minnesota Solar Energy Industries Association (MnSEIA), and the Coalition for Community Solar Access (CCSA). The Joint Parties consist of Nokomis Energy LLC, Clean Energy Economy MN, Enterprise Energy, Novel Energy Solutions LLC, Cooperative Energy Futures, Sunrise Energy Ventures LLC, and SunShare, LLC.

The Company reiterates that we have properly conducted internal transmission studies (ITS) under the Minnesota Distributed Energy Resources Interconnection Process (MN DIP) and that no changes to the MN DIP or the ITS process are necessary to continue to do so. However, the Company believes additional discussions with stakeholders could help clarify the ITS process and lead to potential future refinements or improvements.

These Reply Comments address the issues raised by the above commenters regarding the permissibility and necessity of Xcel Energy's ITS under the MN DIP. Specifically, the Company addresses its authority to conduct the ITS as both a Transmission

Owner and a Transmission Provider, explains the ITS process as allowed under the MN DIP, and discusses the necessity of conducting these internal studies for the safety and reliability of the electric grid.

COMMENTS

The Company replies to the above parties' Initial Comments, following the order of issues set forth in the February 10, 2025 Notice of Comment Period (Notice).[1]

I. Responses to Initial Questions in the Notice

A. Xcel Energy Is Both a Transmission Owner and Transmission Provider.

- *Are the Xcel-transmission studies permissible under the MN DIP? Address specifically, if Xcel Energy is a Transmission Owner or Transmission Provider and whether the internal transmission studies (ITS) are Affected System Studies.*

The Company addressed this issue in its Utility Comments filed on March 13, 2025. As stated in this prior discussion, Xcel Energy owns and operates substations and other transmission facilities and therefore qualifies under the MN DIP definitions as being both a Transmission Owner and a Transmission Provider. We also note that the MN DIP does not limit the authority to conduct transmission studies to one Transmission Provider, such as MISO, but allows "the *appropriate* Transmission Provider" to complete the necessary studies.

The MN DIP provides the following pertinent definitions in its Glossary of Terms:

- ***Transmission Owner:*** *The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.*
- ***Transmission Provider:*** *The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.*

[1] In the remainder of these Reply Comments, unless otherwise noted, page number references are to the Utility Comments or Initial Comments filed by parties as a response to the Commission Notice.

Xcel Energy is a Transmission Owner because it owns or otherwise possesses an interest in the portion of the transmission system relevant to interconnection of DER systems that are interconnected in its service territory. Xcel Energy is a Transmission Provider because it owns, leases, controls, or operates transmission facilities used for the transmission of electricity. Further, because Xcel Energy is a Transmission Owner it directly qualifies as being a Transmission Provider. MISO also qualifies as a Transmission Provider.

Otter Tail Power agrees (pages 2-3) that Xcel Energy qualifies under MN DIP as both a Transmission Owner and a Transmission Provider and should be able to conduct its own internal transmission system impact studies. Similarly, Minnesota Power (pages 2-3) stresses that potential impacts to the transmission system must be assessed for safety and reliability reasons and supports allowing Transmission Owners the flexibility needed to conduct these studies.

Also, the Joint Parties (pages 7-8) note that Xcel Energy seems to meet the definition of a Transmission Owner and a Transmission Provider. However, the Joint Parties assert that Xcel Energy is evading "the spirit and purpose" of the MN DIP by conducting the ITS that are not governed by the MN DIP. To be clear, Xcel Energy has never maintained that the MN DIP does not apply here or that it is not bound by the MN DIP, on the contrary, we have consistently stated that the ITS are allowed under the MN DIP.

Even the CEO group seems to agree (page 8) that Xcel Energy falls under the general definition of a Transmission Provider because it is a Transmission Owner. But the CEO then continues by stating that specifically under MN DIP Section 4.3.6, Xcel Energy should not be considered a Transmission Provider because such an interpretation would be unreasonable and inconsistent. However, there is no basis to treat Section 4.3.6 differently than the rest of the MN DIP.

The Department (pages 4-5) recites these same MN DIP definitions, but also leans on a different definition of a Transmission Provider in another document – the Large Generator Interconnection Agreement (LGIA) between MISO and the Company for a large transmission interconnection above 20 MW. In these specific LGIAs, the Transmission Provider is explicitly defined as MISO or its successor organizations. The CEO group makes a similar argument (pages 12-13). They both seek to proxy the definition of a Transmission Provider in that specific LGIA for use in the MN DIP and replace the current MN DIP definition with a definition from a different document that is used for a different purpose. It is not proper to remove the MN DIP definition retrospectively and to artificially replace it with a different definition for purposes of interpreting the current MN DIP. Further, in the context of that specific LGIA signed by MISO, MISO was performing the single role of being the Transmission Provider and therefore defining MISO as the Transmission Provider would be appropriate. The same is true for how MISO defines Transmission Provider in its FERC tariff. But, under MN DIP, MISO is not always the only Transmission Provider.

Furthermore, the form LGIA developed by FERC does not specify that MISO is always the Transmission Provider. FERC has stated that the LGIA definition of Transmission Provider: *"… shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider*"[2] Accordingly, under the FERC LGIA, the Transmission Provider definition includes the public utility that owns, controls, or operates the transmission or distribution facilities. This is similar to the wording and intent of the MN DIP definition.

Finally, MN DIP clearly has its own definition of Transmission Provider When the language of the MN DIP was developed, the SGIP (Small Generator Interconnection Procedures) was used as a baseline from which edits were made.[3] The SGIP defines "Transmission Provider" as "*The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.*"[4] There is no intent under the SGIP to only include MISO in the definition of a Transmission Provider, and the edits from the SGIP to the MN DIP on this definition similarly do not show any intent to limit this definition to MISO.

All of the above is also consistent with the discussion that occurred during the development of the MN DIP. The DGWG Meeting Summary #3, dated July 28, 2017 (filed in this docket on September 29, 2017) makes it clear that the Transmission Provider can be MISO or the utility. The summary states in part: "*The Transmission Provider definition can be Transmission Operator (usually, an ISO/RTO) or Owner (utility.)*

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[2] Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043, (Issued April 19, 2018), par. 3, note 1.

[3] The Forward to the MN DIP states: "This standards document is modelled after the Federal Energy Regulatory Commission's Small Generator Interconnection Process (FERC SGIP), and explains the process to interconnect Distributed Energy Resources for parallel operation with the Area Electrical Power System (Area EPS)…."

[4] See, February 1, 2017 filing of Environmental Law and Policy Center in this docket at PDF page 65 which notes its various suggested redlines to the SGIP.

States vary, but most often the Transmission Provider is ISO/RTO. The Transmission Provider coordinates the Transmission Impact Study and Transmission upgrades, if necessary."

The CEO group (page 3) claims that previously no stakeholder, not even Xcel Energy, considered the utility to be a Transmission Provider as defined in MN DIP. The above discussion shows that the CEO group is incorrect in its assertions. Later in the Comments (page 8), the CEO group reversed itself and noted that "… Xcel Energy may fall under the general definition of a Transmission Provider because it is a Transmission Owner…"

The ITS is an Affected System Study, as explained in detail in our Utility Comments (page 19). The Joint Parties (page 7) also note that the ITS seems to be an Affected Systems Study. No other commentor disagreed with this.

B. Xcel Energy Is Permitted to Perform the ITS.

- *If the transmission studies aren't permissible should the MN DIP be modified to allow for them to be permissible?*
- *If the transmission studies are permissible, should the MN DIP be modified to add more detail or guidelines to that process? What would the specific edits be and why?*

Our Utility Comments provided robust support and arguments for the ITS, showing that we are not only allowed but also required to perform the ITS. We discussed in length that the MN DIP permits and requires the ITS; demonstrated that NERC requires the ITS; explained that also our affiliates perform the ITS in their operating service territories; established that MISO allows the Company to perform the ITS and that there is no overlap with the MISO review trigger; and, described how our approach is more generous to DER applications that the practices of some other utilities as previously reported in this docket.

Otter Tail Power's Comments (page 3) similarly supported the use of the ITS, stating:

> *Based on these definitions and the clear language in the MN DIP, Otter Tail Power believes Xcel should be able to conduct their own internal Transmission Studies, provided the MISO review trigger threshold of 1 MW aggregate transmission backflow has not been reached. This is because there is potential for adverse impacts on the local Xcel-owned transmission system, even if the MISO review trigger has not yet been met. Xcel conducting internal transmission impact studies under these conditions is permissible and aligns with the statewide interconnection process document, the MN DIP.*

Missouri River Energy Services (MRES), which is also subject to the MN DIP, is an organization of 61 member municipalities that own and operate their own electric distribution systems. MRES also specifically notes that all generation and transmission interconnections must comply with the requirements of the NERC, and that local utility is allowed to establish interconnection standards to ensure electrical system safety and reliability. MRES "Distributed Generation Workbook for Minnesota Members" [5] states:

> Under the FERC regulations … the LOCAL UTILITY is generally obligated to interconnect with, and operate in parallel with, a QF. Parallel operation is the operation of on-site generation by a customer while the customer is connected to the LOCAL UTILITY's system. … All generation and transmission interconnections sought by QFs must comply with the requirements of the North American Electric Reliability Corporation (NERC), Midcontinent Independent System Operator, Inc. (MISO) … and/or other regional transmission providers.
>
> FERC regulations allow the LOCAL UTILITY and MRES to establish interconnection standards to ensure electrical system safety and reliability. The regulations also make it clear that MRES, LOCAL UTILITY and its retail customers are not to be detrimentally affected as a result of a customer interconnection. Thus, other customers should not have a higher cost of electricity or lower quality of service because of the QF's interconnection. MRES and the LOCAL UTILITY are not required to make uncompensated investments to interconnect with QFs.

We also note that the Department has previously acknowledged that transmission studies are necessary. The Department's report to the Legislature regarding Community Solar Gardens (CSG)[6] recognizes the need to conduct transmission studies and that this is especially true in constrained areas that have high DER penetration:

> *The more complex the DER project (and the more congested the grid), the more extensive and complex grid impact studies become, sometimes even triggering a need to analyze potential interconnection impacts on the transmission system. This is especially true in constrained areas, which are often areas with high DER penetration. … Utilities charge developers fees for interconnection applications and interconnection studies including any necessary engineering*

[5] DG Workbook – MN, May 2019, pages 8-9. Available at: https://saukcentre.govoffice2.com/vertical/sites/%7BD28FAE32-EDE3-421C-BD2D-FA8E76EA5F8C%7D/uploads/Distributed-Generation-WORKBOOK.pdf

[6] Community Solar Garden Study, 2024, (December 15, 2024), pdf pages 147-148. Available at: https://www.lrl.mn.gov/docs/2024/mandated/241703.pdf

review, and developers are required to pay system upgrade costs if any are identified through the study process.

The CEO group (page 16) notes that it is reasonable to expect that a majority of the Low- and Moderate Income (LMI) CSG projects (up to 5 MW) and the Distributed Solar Energy Standard (DSES) projects (up to 10 MW) will be developed away from populated areas and be on congested feeders and substations that will exceed the relevant daytime minimum load (DML). Accordingly, consistent with the Department's report, transmission studies should be expected in these constrained areas.

1. The ITS Aligns with the Purpose of the MN DIP

While the CEO group "… recognize and share Xcel [Energy]'s concerns with providing a safe and reliable electric system…" (page 2), they also made several opposite arguments regarding the intent, effectiveness, and clarity of the ITS. For example, they claim that the ITS is not efficient or cost effective and violates "almost every purpose of the MN DIP." (page 3, with similar arguments at pages 11 and 17-18). The CEO additionally argues that the ITS is not easily understandable by everyone or consistent with the interests of the ratepayers and the public. Also, the Joint Parties assert that the technical rationale behind Xcel Energy's use of the ITS remains unclear (page 6).

As was discussed in our Utility Comments, the Company has explained many times, in workgroups and in filings with the Commission, how the ITS works and why it was implemented, including discussing the technical rationale. We provided additional detailed information about the ITS process in our Utility Comments. The Joint Parties recognized this, stating that Xcel Energy "carefully goes through the study process details" and "included specific details on the timelines," concluding that "this information is extremely valuable to interconnection applicants." (page 9)

It is in the public interest that DER interconnections comply with all safety and reliability requirements, whether they are national or local. MRES explained as noted above that all interconnections must comply with NERC requirements and that FERC regulations allow the local utility to establish interconnection standards to ensure electrical system safety and reliability. There are profound benefits to ratepayers and the public in meeting electrical system safety and reliability expectations. The ITS helps to achieve these highly important requirements.

2. No Duplication of MISO Review

Our Utility Comments (page 2) explained that MISO has been clear that the MISO DER AFS process does not preclude other studies of risks to the transmission system from DER projects that do not trigger a MISO review. The MISO process did not remove the need for our internal transmission analysis, and we have modified our process to account for how DER applications are studied for transmission impacts by MISO, verifying that the Xcel Energy ITS and MISO DER AFS are non-duplicative, use different triggers that prompt evaluation of potential adverse transmission impacts, and comply with MN DIP 4.3.6. When a MISO DER AFS review is triggered, then the Xcel Energy ITS is not performed.

We also described (page 11) the MISO led stakeholder meeting series (IPWG) throughout 2022 and that during the IPWG meetings MISO was clear that its DER AFS process would not prohibit Transmission Owners from conducting their own transmission studies on DER interconnection applications. We noted (page 17) that if MISO would have chosen to study all DER at the DML threshold, then there would be only one study process. However, MISO decided to use the threshold of peak load based on the desire for "simplicity and transparency." MISO acknowledged that other than peak load conditions may be used as a trigger for transmission studies by individual Transmission Owners.[7]

Both the Joint Parties and the CEO group criticize our use of DML as a trigger and imply that MISO was not at all concerned about transmission impacts at this level. For example, the Joint Parties state (page 6) without support: "And MISO seems to have no technical concerns until aggregate DER exceeds peak load." The CEO group further claims (page 4) that if NERC requires the trigger for a transmission study based on backflow to the transmission network, then this would mean that MISO is violating NERC standards and claims that Xcel Energy is arguing that it knows more about potential adverse impacts on transmission systems than MISO. These arguments have no merit. MISO was clear that Xcel Energy could perform its own transmission studies, and that the MISO trigger threshold for its studies was not based on what NERC required (as that would be left to the Transmission Owner under the

[7] See, for example, the MISO IPWG PowerPoint presentation of June 6, 2022, at page 5, which states: "MISO proposes to use standardized screening for simplicity and transparency, consistent with other Affected Systems practices, when considering DER impacts on the MISO functional control transmission system. TOs [(Transmission Owners)] would retain the right to perform state-jurisdictional transmission studies, per the applicable Relevant Electric Retail Regulatory Authority (RERRA) rules." This presentation is available at:
https://cdn.misoenergy.org/20220606%20IPWG%20Item%2005%20DER%20Interconnection624982.pdf)

cooperative arrangement with MISO). Instead, the MISO trigger is based on "simplicity and transparency."

The CEO group (pages 3-4, 8-10) argues that under MN DIP 4.3.6 the same entity cannot be both the Area EPS Operator and the Transmission Provider, because the MN DIP Study Process Workflow does not include two different transmission study tracks (one for MISO and one for Xcel Energy) and because two separate study processes would create inefficiencies and potential conflicts. MN DIP 4.3.6 states:

> MN DIP 4.3.6: In instances where the System Impact Study shows potential for Transmission System adverse system impacts, within five (5) Business Days following the identification of such impacts by the Area EPS Operator, the Area EPS Operator shall coordinate with the appropriate Transmission Provider to have the necessary studies completed to determine if the DER causes any adverse transmission impacts.

As shown further above, the clear wording of the MN DIP requires that the Transmission Owner is also considered to be a Transmission Provider. There is no wording or implication in MN DIP that this is not the case. Also, there are no separate or conflicting processes that are in place at the same time for the same interconnection application because there is a clear line with no overlap on when MISO has the role of being a Transmission Provider under the MN DIP process and when Xcel Energy has this role. If the MISO review is triggered, then Xcel Energy will not conduct an ITS.

The Joint Parties and the CEO group also make misleading statements or refer to dated documents. For example, Joint Parties (page 5) incorrectly cite to an older version of the MISO BPM (BPM-0150-r26)[8] for the assertion that MISO "… does not require utilities like Xcel [Energy] to submit projects for transmission study simply because they exceed daytime minimum load." The cited reference to pages 123 and 129 does not say this. MISO understands that Xcel Energy will still be conducting its own transmission studies for DER projects that do not trigger a MISO transmission review.

The CEO group notes that Xcel Energy's ITS applies a different standard than MISO and claims (page 3) that the ITS screening criteria was "rejected by MISO and inconsistent with information provided by IREC and EPRI at a recent DGWG

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[8] Available at: https://cdn.misoenergy.org/20230918%20PAC%20Item%2002c%20BPM-015%20Generator%20Interconnection%20Queue%20Reform%20Redlines630228.pdf

workshop" on battery storage. The CEO group provides no citation for its assertion that the DML was rejected by MISO. It is true that MISO uses a different trigger for the MISO DER AFS, but this is not a rejection of the ability of the Company to use the DML trigger.

The CEO group's Comments reference in several places (pages 3, 7, 12, 17-18) the March 14, 2025 DGWG workshop on battery storage, but these references are mischaracterized and taken out of context. The DGWG discussion on DML was in terms of energy storage combined with large DER (i.e., PV) exporting to the grid. The technical issue at the workshop concerned having energy storage included as part of the load for DER, and that this could reduce the load in the system, which in turn could also reduce the exporting capacity of the DER and keep it from exceeding DML. However, the discussion was only in the context of interconnecting large DER with non-exporting energy storage. This is fundamentally different from the large DER projects that have been the subject of the ITS as these projects do not have energy storage capabilities.

The CEO group describes IREC presentation during the DGWG workshop and then immediately continues with a statement that "The DML is not granular at all." (page 12) However, this is out of the context, and not what IREC said. The CEO group did not provide a citation to the workshop recording where IREC allegedly made this statement, and we did not find such a statement in our review of the entire recording. To the contrary, during the presentation IREC referenced DML as an acceptable method for both export control and criteria for penetration screening, also pointing out that DML is more measurable now compared to before. Furthermore, they also acknowledged that when generation exceeds minimum load, reverse power flow will occur. IREC presentation slides showed that generation that is less than minimum load results in no reverse power. While IREC was speaking in terms of energy storage, the same can be said for exporting generation.

More fundamentally, the DGWG workshop was about the interconnection and study of battery energy storage systems (BESS), and none of the presentations or discussions addressed transmission impacts. IREC and EPRI did not provide any information or statements about transmission studies. Instead, the sections of that workshop that the CEO group cited were addressing use of anywhere from 12-hour values to 8760-hour values of loading information in the context of California LGPs (limited generation profiles) for distribution impacts under which distributed generation can be curtailed, or the battery with PV can be scheduled with import and export limiting during set time periods. The presenters were looking at using a Power

Control System (PCS)[9] but noted that vendors have not yet released equipment that is compliant with this.[10] The presenters also stated that they were still looking for a pilot to test their theories.[11] They theorized that using batteries with PCS could result in large increases in distribution hosting capacity.[12] There was no mention on whether this could, or should, be considered for implementation to address transmission study thresholds, or transmission safety and reliability issues.

3. No Communication that Xcel Energy Would Not Use DML for the ITS

Both the Joint Parties (pages 2-4, 6) and the CEO group (page 6) again raise issues about Xcel Energy's past statements and filings, claiming that we had agreed to rely solely on MISO's screening criteria and study processes, that we would not use DML as a threshold to trigger a transmission study, and that we had proposed changes to the MN DIP that were never implemented to allow the ITS. Our Utility Comments (pages 20-23) already addressed these allegations in detail and noted that they were all without merit. All our prior statements and proposed MN DIP changes were made in the context of the MISO ASIS study process and did not involve the Company's ITS. That parties are repeating these same assertions all over again out of the context is misleading and disingenuous.

No commenter, including the Joint Parties and the CEO, rebutted the Company's responses to the above allegations, as set forth in our March 13 Utility Comments. Therefore, our prior responses remain unchallenged, and we stand by and reincorporate them fully here.

4. The ITS Is Allowed by State Statutes

Our Utility Comments (pages 8-9) included extensive detail rebutting prior contentions of MnSEIA and others on the applicability of various statutes, such as Minn. Stat. §§ 216B.1611, 216B.03, 216B.05, and 216B.16. The Company included as an attachment excerpts from the Commission's September 24, 2024, Appellate Brief on the Technical Planning Standard (TPS) Appeal from Docket No. E-002/C-23-4246 that explained how these statutes are to be applied. Based on the Commission's reasoning, our Utility Comments demonstrated why these statutes are not applicable to the ITS and do not prohibit the use of the ITS.

[9] The link for the recording of the March 14, 2025, DGWG Meeting, is available at: https://minnesotapuc.granicus.com/player/clip/2503?view_id=2&redirect=true ("DGWG Battery Link") See the DGWG Battery Link at about 1:36:05 – 1:36:10.
[10] See, DGWG Battery Link at about 1:34:48-1:34:58.
[11] See, DGWG Battery Link at about 1:36:20-1:36:33.
[12] See, DGWG Battery Link at about 1:37:15 – 1:37:20.

Further, on April 14, 2025, the Minnesota Court of Appeals issued its decision affirming the Commission Order dismissing the Complaint challenging the Company's implementation of the TPS.[13] The Court of Appeals determined that the Commission did not need to approve the TPS before the Company implemented this, and the Court of Appeals rejected arguments that the many statutes cited by MnSEIA required a different result. In reviewing the history of the TPS issue, the Court of Appeals (pages 9-10, and *4) noted that the Commission determined that the TPS aligns with Xcel Energy's approach to identify and address system limitations and that this approach fosters interconnections rather than violates state law. By analogy, the same reasoning applies to the Company's implementation and use of the ITS.

Instead of addressing our discussion about these statutes as set forth in our Utility Comments, the CEO group repeats their same allegations. The CEO group argues incorrectly again (pages 4, 10-11, 13-15), based on various statutes, that the Commission must approve the ITS before it can be implemented. For example, the CEO group again attempts to shoehorn the ITS into the definition of "rate" and claims that the ITS must therefore be "just and reasonable" and approved by the Commission according to Minn. Stat. §216B.02, subd. 5 and § 216B.03. The Joint Parties (pages 2, 8) echo some of these same arguments.

The Company's Utility Comments extensively addressed the non-applicability of these various statutes. It is frustrating that the CEO group and the Joint Parties, again, have decided not to respond to the points made by the Company. The Company has already thoroughly rebutted these allegations and refers the Commission to its March 13 Utility Comments. The Company stands by its prior unrebutted responses.

5. Mischaracterization of the Development of the ITS

The CEO group (pages 5-6) and the Joint Parties (pages 1-5) mischaracterize the history of the development of the MISO DER AFS as well as the development of the prior MISO ASIS Agreement. The MISO ASIS Agreement was a specific agreement between Xcel Energy and MISO. It was never implemented, and it is completely separate from the transmission study processes that were created later - the MISO DER AFS process and the Company's ITS process.

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[13] See, *In the Matter of the Formal Complaint and Request for Relief by the Minnesota Solar Advocates*, Docket A24-0845, Minnesota Court of Appeals, April 14, 2025 (2025 WL 1098737)

The CEO group (page 6) falsely imply that the first time that Xcel Energy had informed the Commission (or developers) about the MISO ASIS agreement was in December 2021 when it filed the MISO ASIS agreement with the Commission. The CEO group cites to the October 4, 2023 filing by Nokomis that contains this false narrative. A proper summary of the history of these communications in 2021 is reflected in the Company's March 21, 2022 Comments in this docket, page 2.

The CEO group (page 7) states that after the Commission's March 31, 2022 Order stayed the MISO ASIS Agreement, neither the Company nor the Commission took any further action until Xcel Energy announced in August 2023 the upcoming implementation of the ITS. However, the MISO ASIS Agreement has never been utilized and the ITS is not part of the MISO ASIS Agreement.

The Joint Parties (page 2) claim that the ITS has been implemented outside of MN DIP, creating another "on hold" process that is not in MN DIP and therefore unenforceable. They continue by stating, "Xcel explains that it has found a loophole in MN DIP that allows it to be both hands in the handshake…." The Joint Parties repeat this theme on page 8. Xcel Energy has never claimed that there is a loophole in MN DIP, which clearly allows for transmission studies by the Transmission Owner and the Transmission Provider. The on-hold and queue process under MN DIP is discussed further below.

The Joint Parties (page 3) falsely claim that the Commission "… explicitly stated that this [(use of the MISO Ad hoc process)] would not require Xcel [Energy] to put projects in an 'on hold' process, but rather that Xcel [Energy] should use the long-standing Ad-Hoc Process for MISO transmission studies." The Commission only speaks through its written orders[14] and has never made these statements in a written order. Instead, the March 31, 2022 Order on this issue notes (page 10) that the Order only applies to the implementation of the MISO ASIS itself and does not apply to any other requirements in the Order (including those related to the on-hold process). Also, instead of ordering Xcel Energy to continue to use the MISO Ad Hoc process (that now no longer exists), the Commission Order explicitly stated that the stay of the MISO ASIS agreement "… does not impact the current MN DIP-approved Affected System Study process used by utilities and MISO."

[14] See, *In re Excelsior Energy, Inc.*, 782 N.W.2d 282, 296 (Minn. Ct. App. 2010) (The Commission "speaks only through written orders. See Minn. Stat. § 216B.33 (2008) (stating that all orders of the commission must be in writing)."

C. The MN DIP Should Not be Modified.

The CEO group (page 4) asserts that Xcel Energy believes that the MN DIP can be changed without Commission approval. Again, this is far from the truth, as we have always recognized that any changes to the MN DIP require Commission approval. However, the ITS has been properly implemented as it is consistent with the MN DIP and does not require any changes to the MN DIP.

The Joint Parties assert that if some version of the ITS is allowed, then the MN DIP should be modified to incorporate the ITS. Yet, the Joint Parties do not specify the specific amendments that they claim would be necessary to allow the MN DIP to be consistent with the use of the ITS other than how queues are treated under MN DIP. The Joint Parties incorrectly assert that Xcel Energy has endorsed the need to modify the MN DIP to accommodate the use of the ITS. Xcel Energy has never maintained that position. The document referenced by the Joint Parties in their footnote 37 is a March 21, 2022 filing in reference to the MISO ASIS Agreement, which has never been used. The Company was clear in its Utility Comments that the March 2022 filing was limited to the MISO ASIS Agreement and responded in detail to prior false representations by the Joint Parties. Here, the Joint Parties are again repeating representations that have already been rebutted by the Company.

The ITS uses the same queue process as is used for the MISO DER AFS, which is the same queue process that was used for the MISO Ad Hoc process. The Commission's March 2022 Order specifically allowed the use of the MISO Ad Hoc process, so there is nothing new with how the queue process under MN DIP is used for transmission studies. The Joint Parties (page 8) quote four words from MN DIP 1.8.3, but omit other critical language. This provision states: "*The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region (i.e. feeder, substation, etc.)*" This is how Xcel Energy has been employing the queue process for transmission studies. The queue is managed by geographic region, with it being separately managed by feeder and by substation. Nothing about the use of the ITS has changed this.

Consistent with this, if a substation has more than one feeder (Feeder A and Feeder B), Feeder A may have a long queue, and projects may be on hold for some period before they start their Distribution System Impact Study (SIS). Feeder B might have a very short queue, and projects begin their Distribution SIS faster even though they may have a later Deemed Complete date than projects on Feeder A. During the Distribution SIS for a project on Feeder B, there may be a need to have a transmission SIS (either MISO DER AFS, or ITS) and it will start that process. For purposes of this example, let's assume that a full transmission study is needed and has been started. If after this the next project on Feeder A is also flagged for needing a transmission SIS (either MISO DER AFS, or ITS), it will need to await the results of the transmission SIS on Feeder B that is already underway. The Joint Parties seem to be arguing that projects on Feeder A with an earlier Deemed Complete date should not have to wait for a transmission study to be completed for the project on Feeder B. However, in reality this would mean that no project on Feeder B could begin its Distribution SIS until all projects that have an earlier Deemed Complete date on Feeder A have a signed Interconnection Agreement. If this is the position of the Joint Parties, it would result in significant delays in processing interconnection applications and would not align with the MN DIP.

The Joint Parties (pages 10-11) seem to be under the impression that in the example above, once a project on Feeder B starts its transmission study, all projects on Feeder A will be put on hold. This is not correct. Those projects on Feeder A that have already completed their Distribution SIS will continue and not be placed on hold due to the transmission System Impact Study for the project on Feeder B.

II. ITS Process and NERC Standards

- *Based on the information derived from the two reports provided to the DGWG on this topic:*
  - *Is the exact timing and quarterly processing of the Xcel-transmission studies open to being modified? Would it be beneficial to include stakeholder input?*
  - *Is there any information that deserves further investigation or exploration beyond what was discussed in the reports that the Commission should consider?*

The Department (pages 5-6) notes that the ITS process results in more transmission studies being conducted, and this increases the time and expense to complete the interconnection projects even when no needed transmission upgrades are identified. The Department (page 6) states that it may be useful to include stakeholder input for guidelines for efficient completion of projects and to evaluate for conflicting interests. The Department notes that stakeholders might provide useful guidance on how MN DIP might be modified. The CEO group (page 15) also recommends that a workgroup be formed to discuss whether the timing and processing of the studies under the ITS should be modified.

The Company is open to productive dialogue. The Company's Utility Comments (page 25) stated:

> The Company notes that the ITS process is still in its infancy. The Company suggests that it be allowed to gain some real-world experience with examining the results of the ITS studies for some period so as to

have a better-informed base before engaging in further discussions to modify the process. Evaluation of these study results may reinforce the need for the current ITS process or show potential for other viable approaches. Also, the Company suggests that any participant seeking changes to the ITS should be productive and come forward with a realistic alternative to the current ITS that would also comply with NERC standards. Just saying "No" to the ITS would not likely lead to a productive discussion. To be clear, the Company is open to feedback and has discussed with stakeholders at the DER quarterly workgroups their questions and concerns. We believe this dialogue should continue in the DER workgroup process, including discussion on the exact timing and quarterly cadence of the ITS.

The Department did not specify what type of conflict of interest it was concerned about. Perhaps the concern is how Xcel Energy and MISO interact together in addressing the needs of the transmission system, with each doing their own transmission system impact studies under different triggers. The triggers do not overlap. The transmission system impact studies, whether done by Xcel Energy or MISO, would identify specific issues with interconnecting the DER project and detail the needed modifications to the transmission network that would be required to address this. Regardless of whether Xcel Energy or MISO performs the transmission system impact study, the next step to address the costs of these upgrades would be through a facilities study. Xcel Energy would perform the facilities study regardless of whether Xcel Energy or MISO performed the transmission system impact study. Accordingly, we do not see any risk of a conflict of interest as expressed by the Department.

The CEO group (page 16) points to the SunShare Reply Comments in Docket No. 25-76 and seeks a better understanding of MISO's DER AFS process, including the opt-out process referenced by SunShare. A group of Michigan utilities (Consumers Energy, Detroit Edison, ITC Holdings, and Wolverine Power) on May 29, 2024 had requested from MISO an alternative approach whereby utilities could perform their own transmission system impact studies in lieu of having MISO perform any studies for DER applications. They asked that MISO allow utilities to opt-out of using the MISO DER AFS.[15] There is no opt-out to the MISO DER AFS, and MISO did not

[15] The May 29, 2024 presentation on this proposal to MISO is at this link: https://cdn.misoenergy.org/20240717%20PAC%20Item%2005%20DER%20AFS%20Presentation638489.pdf

allow an opt-out. In a posting dated October 16, 2024, MISO noted that it would further address this at a future meeting.[16]

The Joint Parties (page 7) raise the following questions: "If NERC requires the threshold to be DML exceedance, then why can't Xcel quote anything that says that, and why isn't MISO doing it?" They raise a similar question about MISO (page 9). The Company already addressed this question above and in its prior Utility Comments regarding MISO. In the Utility Comments, we also attached and provided citations to the pertinent NERC requirements; we provide further explanation below.

The language from NERC FAC-002-4 makes mandatory the study of the reliability impact of a DER by each Transmission Planner.

> FAC-002-4
> *R1. Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6.*

Both MISO and Xcel Energy are a Transmission Planner[17]. MISO is also the Planning Coordinator. MISO and Xcel Energy have coordinated on how to divide this duty to study the reliability impact in the context of DER interconnection applications. MISO conducts studies based on its trigger for review. Other studies that are required by NERC in this context are performed by Xcel Energy. The requirement to perform a study is triggered when the DER interconnection application seeks to make a "qualified change" as defined by MISO.

For the definition of the MISO "qualified change," we look to the MISO BPM-020-r31, which states as follows:

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[16] See, https://www.misoenergy.org/engage/MISO-Dashboard/alternative-approach-der-affected-system-study/ under the Update box for 10/16/2024.

[17] MISO's BPM-020-r31 (August 1, 2024) (https://cdn.misoenergy.org/20240605%20PSC%20Item%2008%20BPM-020-r31_redlines633150.pdf) shows that in the context of ITS which is based on bottom-up projects that Xcel Energy is a Transmission Planner. This states: "*2.3.1.1 Bottom-Up Projects Bottom-up projects include transmission projects classified as other projects and Baseline Reliability Projects. Bottom-up projects that are ultimately classified as other projects or Baseline Reliability Projects are not cost shared and are generally developed by Transmission Owner(s), via their role as the NERC Transmission Planner (TP), to address localized Transmission Issues and reliability-related Transmission Issues including, but not limited to, compliance with the NERC reliability standards.*" See also, this document at PDF page 88: "*In accordance with their obligations under the NERC TPL standards, NERC Transmission Planners (which are generally Transmission Owners in MISO)….*"

Existing interconnections of transmission facilities or electricity end-user facilities seeking to make a qualified change on the transmission system needs to report the qualified change to the MTEP Portal. The qualified change is defined as: i) transmission system topology change; ii) protection configuration change that could negatively impact contingency performance, short circuit, or dynamic performance; iii) change the electrical characteristics of a circuit (i.e., change of impedance, current transformers) that could negatively impact contingency performance, short circuit, or dynamic performance.

DER interconnection applications that cause back-flow on to the transmission network meet these criteria under category ii or iii. Xcel Energy very often needs to adjust relay settings (transmission protection configuration) to accommodate these DER interconnections to account for power injection at the end of a feeder rather than solely a load. Also, the electrical characteristics of a circuit with the addition of a current injection device (inverter) will often change the Thevenin equivalent impedances seen by the transmission system. Further, the additional power injection from a DER can change the flow on the line and very likely impact the contingency performance. The backflow in excess of DML onto the transmission system has the potential for Transmission System adverse system impacts. A study needs to be performed to determine whether there in fact will be any adverse system impacts. NERC has provided related guidance and requirements regarding the bulk system, and Xcel Energy is obligated to follow these standards.

It appears that the CEO group and Join Parties are assuming that there will never be a time when a PV DER will be producing at full capacity during DML. This is an incorrect assumption. In the case of large PV, there is always a potential for DER PV to produce at full capacity during DML. Therefore, there is always potential for large DER to cause backflow to the transmission system at DML just like it produces backflow to the distribution system. The reason why we use DML as a trigger for performing the ITS is because this is the point at which power backflows onto the transmission system because the DER total solar power at the substation exceeds the minimum load that would take place during the day. This is roughly what happens on spring days in Minnesota when we have mild temperatures with very low load on our system while also having clear sunny days which will provide a full solar output. During these periods we will have backflow on the transmission system if the total MW of DER exceeds the DML. We use DML because at this level we know we will have excess flows onto the transmission system. At this level there is potential impact on the transmission system. Thus, a study is needed to assess with a System Impact Study the reliability of the transmission system with the additional DER.

The Joint Parties (page 9) ask why Xcel Energy does not allow cluster studies for the ITS. This echoes a point that they made in their December 13, 2024 report. Xcel Energy responded to this in its March 13 Utility Comments (page 14) as follows:

> The Company may use cluster studies for the ITS, which allows the processing of more projects per quarterly study. The Transmission SIS Agreement also clearly provides for a cluster study (see the last page of Attachment E). The critique of the Joint Parties regarding the lack of cluster studies for ITS is therefore not correct (December 13, 2024 Report, p. 1).

The Company relies on the previous unrebutted response on the cluster study issue as set forth in the Company's Utility Comments.

The Joint Parties (page 9) also raise the following questions:

> It is not clear that this [(quarterly)] cadence or formality is needed at all. Daytime minimum load can be determined without a system impact study, so the transmission study could be performed at almost any stage in MNDIP. Shouldn't Xcel be conducting its own transmission studies on an as-needed basis? The Commission or the DGWG should carefully examine whether Xcel can conduct transmission studies in parallel with the existing MNDIP timelines and process.

Daytime minimum load is not static and can change. When a distribution System Impact Study is started, we take current information in our systems and compare that to the information in the interconnection application at hand to determine if a trigger for a MISO DER AFS or ITS has been met. This analysis is done when there is a need for it. There is a need for it at that point in time to determine whether current information shows that a transmission study needs to be performed for the project at hand. Our Utility Comments explained why the quarterly cadence is the most efficient way of conducting these studies and that this saves developers' expense and leads to a predictable schedule. We are open to discussing the study cadence and related issues in a workgroup session, but the current process aligns with MN DIP.

The Joint Parties (page 10) take the position that the ITS process should sunset if few or no transmission upgrades are identified in the completed ITS. As long as the ITS is required under NERC regulations, the Company must continue to use it. Implementing an arbitrary ITS sunset based on past experience would not eliminate potential transmission impacts in the future and would violate NERC standards.

III. Low-to-Moderate Income Accessible Community Solar Garden Program (LMI CSG)

- *How should the Commission consider impacts of Xcel-transmission studies on interconnection-related or state-goal related programs; such as LMI CSG Program?*

The Department (page 6) states that a large portion of DG interconnection applications will be subject to a costly transmission study that has not triggered a MISO review and study, and that perhaps over ninety percent of the LMI CSG program applications currently in the interconnection queue have been impacted. The CEO group (page 16) expresses similar concerns for LMI CSG and DSES applications up to 10 MW proposed to be developed away from populated areas with congested feeders and substations. The CEO notes (page 2) that the ITS makes it difficult for Minnesota to meet its clean energy goals.

A primary purpose of the MN DIP is to allow for safe and reliable interconnections.[18] This cannot be compromised by attempting to achieve some other noteworthy goals or efforts, as the Department and CEO group seem to suggest. Meeting the clean energy goals is part of the function of the Integrated Resource Plan (IRP) and Integrated Distribution Plan (IDP). The legislature has also established the structure for a cost sharing plan for reactive upgrades to help achieve more DER interconnections, and this is the topic in Commission Docket No. 24-288. The Commission is also studying "proactive" upgrades in Docket No. 24-318. Additionally, the Commission has already authorized cost sharing up to $15,000 for systems up to 40 kW (small cost sharing program) through its December 19, 2022 Order in Docket No. 18-714. The legislature under Minnesota Session Laws 2023, Chapter 60, H.F. No. 2310, Article 11, Sec. 2, Subd. 10 authorized $250,000 for this small cost sharing program as well as nearly $10 million for creating more DER hosting capacity in certain areas, which is addressed in Docket No. 23-458.

The CEO group (page 16) requests that the Company provide an analysis of the number of feeders and substations where projects between 5 and 10 MW would trigger an ITS. We provide below in Table 1 a listing of 37 substations where a DER of any size will trigger an ITS study. If a developer wants to know whether a new 5-10 MW project will trigger an ITS on any other substation, we have not done that

[18] See, for example, the Forward to the MN DIP, which states in part: "These updated Minnesota interconnection standards strive to: … 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…. At a minimum, these standards must: 1) To the extent possible, be consistent with industry and other federal and state operational and safety standards…."

analysis. A pre-application report would provide that information on a project specific basis.

Table 1
Table 1: Substations Likely Needing an Internal Transmission Study (DER>DML)

AVN	BEG	BLF
BIS	BLH	BLL
BUR	CGR	CHE
DOC	EKO	FAP
FRM	FSL	GLD
HAS	HEC	HUG
KIM	LAP	LIN
MAP	MYN	ORO
PBE	SAK	SAR
SCL	SDX	SJO
SMT	STO	VIL
WAB	WCS	WKN
YAM		

IV. JSA Request for Stay and Referral to DGWG

- How should the Commission respond to JSA's request of the following?
  o Should Xcel's internal transmission study be stayed until the Commission grants approval?
  o Should the Commission open an investigation into Xcel's internal transmission studies and refer the matter to the Distributed Generation Working Group (DGWG)?

The CEO group (pages 16-17) requests that the Commission stay the ITS "… until the Commission investigates the impact of this process on the interconnection of projects in Minnesota, especially the LMI CSG program, which has yearly program limits." The Joint Parties (page 11) also support a stay of the ITS. If the Commission were to stay the ITS, then this would create a conflict for Xcel Energy between federal law requirements[19] and Commission requirements. Xcel Energy therefore opposes a stay of the ITS.

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[19] Xcel Energy has an affirmative responsibility to comply with standards developed by the National Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC) when planning, maintaining, and operating its transmission system as clearly reflected in the statute creation and

The Joint Parties (page 11) support referring the ITS process to the DGWG for further evaluation. The CEO group (page 17) recommends that the Commission open an investigation, arguing that the Company has not shown why the ITS is needed to meet NERC requirements, that MISO uses a different triggering threshold for the MISO DER AFS, and that IREC/EPRI during the DGWG subgroup meeting on battery storage supported a different approach. The Company has rebutted all of these arguments above. No commenter has proposed anything close to a viable alternative to the current ITS for complying with NERC regulations. The Commission should have before it a potentially viable alternative proposal before engaging the DGWG to discuss proposed alternatives to the current ITS.

V. Are There Other Issues or Concerns Related to This Matter?

The Department (page 7) notes the need for additional data regarding how many projects Xcel Energy is sending to MISO and how many are undergoing an ITS. Transmission study information is included in the monthly Public DER Queue report posted on our website.. However, we currently do not specify the type of transmission study in our monthly public posting. The Company includes as Attachment A an excerpt of the April 1, 2025 monthly queue report that shows projects that have triggered transmission review and remain in that MN DIP step. To allow for additional tracking, the Company could also provide in the Public DER Queue report the type of transmission study that is in progress per project but may need some reasonable amount of time to implement this.

For clarification, we provide additional information on transmission studies below in Table 2.

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operation of the Electric Reliability Organization (ERO), a position held by NERC. Specifically, section 215(b) of the Federal Power Act states as follows: "JURISDICTION AND APPLICABILITY.—(1) The Commission shall have jurisdiction, within the United States, over the ERO certified by the Commission under subsection (c), any regional entities, and all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 201(f), for purposes of approving reliability standards established under this section and enforcing compliance with this section. All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section."

Table 2: Projects in Transmission System Impact Studies (as of 4/8/2025)[20]

Type of Study	In Progress	Completed	Required System Upgrades
Internal	3	18	0
MISO	23	13	4

Conclusion

Xcel Energy is a Transmission Owner and also a Transmission Provider when it is conducting the ITS, as defined in the MN DIP. Our ITS process is consistent with the MN DIP and with the discussions that took place in 2017 relating to the development of the MN DIP.

Before the ITS was implemented, the Company provided advance notice in 2023 to the developer community. The Company has also made significant efforts to inform and educate developers on the ITS process. The ITS is necessary to operate a reliable and safe transmission system, and also is required by NERC regulations.

The Company continues to suggest an open stakeholder working group to further discuss refinements to the ITS in a productive manner, with the understanding that safety and reliability concerns and technical requirements around transmission analysis are critical for these discussions. It is also important that participants communicate honestly and avoid misleading statements that do not align with historical or technical facts. We are open to making process improvements and providing additional information as part of our monthly Public DER Queue report.

Dated: April 17, 2025

Northern States Power Company

[20] In Table 2, the "Completed" column includes those projects that were just recently completed and therefore, due to timing issues in gathering the data, does not match the numbers in Attachment A.

Application Number	Project Type	Date Application Deemed Complete	Interconnection Process Track	Proposed DER capacity (kW AC)	Substation	Feeder	Application Status
05800267	Distributed Generation	6/21/2024	Study	3000	ANN	ANN021	Transmission System Impact Study
05800381	Distributed Generation	6/4/2024	Study	5000	ATW	ATW061	Transmission System Impact Study
04083597	Solar*Rewards Community	11/10/2020	Study	1000	AVR	AVR081	Transmission System Impact Study
05830746	Distributed Generation	7/29/2024	Study	4999	BEL	BEL061	Transmission System Impact Study
05462915	Solar*Rewards Community	12/14/2023	Fast Track	1000	CLC	CLC022	Transmission System Impact Study
05800010	Distributed Generation	6/24/2024	Study	4999	CTF	CTF021	Transmission System Impact Study
05518283	Solar*Rewards Community	7/25/2023	Fast Track	1000	DAS	DAS061	Transmission System Impact Study
05799921	Distributed Generation	6/13/2024	Study	5000	EGL	EGL021	Transmission System Impact Study
06000277	Distributed Generation	10/29/2024	Study	3750	ESG	ESG001	Transmission System Impact Study
05800187	Distributed Generation	6/10/2024	Study	3750	FAP	FAP061	Transmission System Impact Study
05799930	Distributed Generation	6/13/2024	Study	2000	FIC	FIC031	Transmission System Impact Study
05800728	Distributed Generation	6/25/2024	Study	3000	GAY	GAY002	Transmission System Impact Study
05800750	Distributed Generation	7/12/2024	Study	2000	GAY	GAY002	Transmission System Impact Study
05516019	Solar*Rewards Community	10/24/2023	Fast Track	1000	GRC	GRC312	Transmission System Impact Study
05799953	Distributed Generation	6/4/2024	Study	5000	GRC	GRC312	Transmission System Impact Study
05800290	Distributed Generation	5/28/2024	Fast Track	5000	GRC	GRC312	Transmission System Impact Study
05800014	Distributed Generation	8/14/2024	Study	4999.972	HUG	HUG321	Transmission System Impact Study
05800031	Distributed Generation	5/16/2024	Study	5000	KAN	KAN022	Transmission System Impact Study
05800003	Distributed Generation	6/4/2024	Study	5000	LIN	LIN031	Transmission System Impact Study
05800005	Distributed Generation	6/21/2024	Study	4999	MAZ	MAZ021	Transmission System Impact Study
05799967	Distributed Generation	6/4/2024	Study	4000	MDF	MDF021	Transmission System Impact Study
04985255	Solar*Rewards Community	6/1/2023	Fast Track	1000	MGN	MGN211	Transmission System Impact Study
05799961	Distributed Generation	5/16/2024	Fast Track	4000	MNV	MNV211	Transmission System Impact Study
05799995	Distributed Generation	6/11/2024	Study	4999	MPN	MPN081	Transmission System Impact Study
05991551	Distributed Generation	11/13/2024	Study	5000	MRN	MRN021	Transmission System Impact Study
05800034	Distributed Generation	6/25/2024	Study	4.999	NER	NER021	Transmission System Impact Study
05800028	Distributed Generation	6/24/2024	Study	3250	NER	NER021	Transmission System Impact Study
05800709	Distributed Generation	6/25/2024	Study	4999	NER	NER021	Transmission System Impact Study
05800721	Distributed Generation	6/13/2024	Study	4999	NER	NER021	Transmission System Impact Study
05800013	Distributed Generation	5/29/2024	Study	5000	NOF	NOF072	Transmission System Impact Study
05800061	Distributed Generation	5/16/2024	Study	3250	NOF	NOF072	Transmission System Impact Study
04179455	Solar*Rewards Community	1/14/2021	Fast Track	1000	PAT	PAT312	Transmission System Impact Study
05799965	Distributed Generation	6/20/2024	Study	4999	PIL	PIL022	Transmission System Impact Study
05800038	Distributed Generation	6/24/2024	Study	4999	PIL	PIL022	Transmission System Impact Study
05800687	Distributed Generation	6/25/2024	Study	4999	PIL	PIL022	Transmission System Impact Study
05799963	Distributed Generation	6/7/2024	Study	5000	PIP	PIP090	Transmission System Impact Study
05799970	Distributed Generation	6/21/2024	Study	4999	RCH	RCH061	Transmission System Impact Study
05612251	Solar*Rewards Community	12/27/2023	Fast Track	1000	ROC	ROC091	Transmission System Impact Study
05800303	Distributed Generation	6/8/2024	Fast Track	4999.972	ROC	ROC091	Transmission System Impact Study
05806380	Distributed Generation	7/2/2024	Study	4000	SCL	SCL311	Transmission System Impact Study
05674613	Solar*Rewards Community	12/21/2023	Study	1000	SDX	SDX311	Transmission System Impact Study
05799989	Distributed Generation	6/12/2024	Study	3000	SMT	SMT072	Transmission System Impact Study
05799958	Distributed Generation	6/18/2024	Fast Track	3750	STO	STO002	Transmission System Impact Study
05800016	Distributed Generation	6/20/2024	Study	4999	TSS	TSS061	Transmission System Impact Study
05799952	Distributed Generation	5/31/2024	Study	5000	WEB	WEB021	Transmission System Impact Study
05799966	Distributed Generation	5/31/2024	Study	5000	WEB	WEB021	Transmission System Impact Study
05799924	Distributed Generation	6/19/2024	Study	4950	WEF	WEF061	Transmission System Impact Study
05799928	Distributed Generation	5/29/2024	Study	4950	YLM	YLM211	Transmission System Impact Study

CERTIFICATE OF SERVICE

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

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

<u>xx</u> electronic filing

DOCKET NO. E999/CI-16-521

Dated this 17th day of April 2025

/s/

____

Victor Barreiro
Regulatory Administrator