414 Nicollet Mall
Minneapolis, MN 55401

March 28, 2019

**—Via Electronic Filing—**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
DISTRIBUTION SYSTEM/HOSTING CAPACITY STUDY
DOCKET NO. E002/M-18-684

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Reply Comments in response to the Comments filed by parties on February 28, 2019.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on all parties on the attached service lists. Please contact me at bria.e.shea@xcelenergy.com or 612-330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosure
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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|---|---|
| Dan Lipschultz | Vice Chair |
| Matthew Schuerger | Commissioner |
| Katie J. Sieben | Commissioner |
| John A. Tuma | Commissioner |

IN THE MATTER OF THE XCEL ENERGY 2018 HOSTING CAPACITY REPORT UNDER MINN. STAT. § 216B.2425, SUBD. 8

DOCKET NO. E002/M-18-684

**REPLY COMMENTS**

## INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments in response to the Comments filed by parties on February 28, 2019 regarding our third Hosting Capacity Analysis (HCA) report.

Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning and we are proud of the significant progress we have made to advance the value of this report in a meaningful way to date. We have made these changes and advanced our analysis in response to stakeholder feedback, learnings from the few other national utilities that are also doing this work, and our work with EPRI. We note that there were only two parties who provided comments on our 2018 report (the Department of Commerce and Fresh Energy) – a notable decrease from our 2017 report with five commenting parties.

The Department concluded that our 2018 HCA is complete, and requested additional information in a number of areas and made three recommendations – all of which we accept and respond to in this Reply. The context of Fresh Energy's comments was largely around feedback gathered from Developers. We too have gathered feedback from Developers, as discussed in our HCA filing. Most recently, we gathered feedback from the Solar*Rewards Community (S*RC) Workgroup, where approximately 20-30 solar Developers and other stakeholders regularly interact with Xcel Energy engineering, program, and other personnel. In 2017, we also met with a small group of Developers and other stakeholders to discuss the 2016 results and what they would want to see in our 2017 analysis, which resulted in our providing the first heat map of the HCA results.

In our mid-2018 engagement with the S*RC Workgroup, several members shared that they had not used the HCA map; others had visited our website and were aware of the HCA, but did not regularly use the HCA map. Others discussed ways they felt the map would be more useful – specifically, more frequent updates and more information surrounding the substation, feeder, and other equipment. From the discussion, it was clear that the members did not have a strong understanding of HCA and how to apply it. As a result, our engineering team focused the balance of our time at that meeting on clarifying aspects of the HCA and how it relates to steps in the interconnection process.

In response to this feedback and other stakeholder feedback through the annual HCA filings, while we have made significant progress, we acknowledge that more could be done to continue to refine our hosting capacity tool and analysis. However, aspects of the feedback shared in Comments demonstrate misperceptions and misalignment of the role of the HCA in relation to Minnesota's recently-revised statewide standard interconnection process – also referred to as Minnesota Distributed Energy Resource Interconnection Process, or MN DIP.

For example, the accuracy expectations for the HCA contained in Fresh Energy's Comments are that it match the results from the pre-application data report ("capacity screens" for Solar Gardens). The pre-application data report simply provides existing system data; this is not an analysis, and does not offer capacity "results" per se, but instead provides an up-to-date snapshot of system information. In contrast, hosting capacity does run some preliminary analysis and provides an estimate of available capacity at a particular location. The tools are complementary and should not be viewed as interchangeable. Further, in assessing HCA accuracy, it is neither fair nor appropriate to compare the results of the HCA with the results from the pre-application data request step of the MN DIP, as was expressed in the survey results.

The revised MN DIP standards carefully define pre-application data, screening, and study processes. The standards do not involve, require, or rely-on hosting capacity maps from any utilities. Other states at the forefront of HCA, such as New York or California, have contemplated HCA in the context of a statewide effort in order to better coordinate with statewide interconnection standards. However, the MN DIP *precludes* the use of hosting capacity for technical screening without Commission action to make it part of the uniform statewide standard. Further, it would be important to consider the implications of narrowly focusing a hosting capacity tool and analysis on automating interconnection studies; we believe this may actually limit the capabilities and use of the tool for other planning use cases.

Our objective for the HCA is aligned with Minn. Stat. § 216B.2425[1] and the Commission's Order to serve as a "starting point" for interconnections.[2] In our view, the current HCA plays an important role in streamlining the interconnection process by assisting Developers in choosing sites that potentially require only screening or a less involved study, as intended by the statute. It is apparent from comments that some parties want or think the HCA should supplant actual steps in the MN DIP. That said, we believe we may be at a critical juncture where the Commission may need to re-iterate or clarify the objectives of the HCA to avoid potentially conflicting objectives or misplaced expectations on future HCA reports.

While the HCA report provides insight as to potential feeder capacity – it is only *one tool among several* necessary to accommodate and integrate Distributed Energy Resources (DER) without causing adverse impacts on the distribution system; the determination of exactly where and how much DER can be added to our system is resolved through the processes that comprise the MN DIP. If the Commission determines HCA should become part of MN DIP and as such, all utilities must perform an HCA – among other considerations, it would be important for the Commission to clarify the role of HCA in the standardized interconnection process along with other supporting details, such as how frequently the analysis should be performed.

We look forward to continuing to refine and advance our HCA in concert with the industry and the Commission's expectations.

Below we provide our response to the Department and Fresh Energy's Comments.

## REPLY COMMENTS

### A. Bus Voltage Sensitivity

The Department requested that Xcel provide additional information on translating the theoretical gains of hosting capacity demonstrated by the Company's bus voltage sensitivity analysis into actual gains of hosting capacity, which should include information on the technological options available to the Company, the estimated

[1] Subd. 8. **Distribution study for distributed generation**. Each entity subject to this section that is operating under a multiyear rate plan approved under section 216B.16, subd.19, shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subd. 2.

[2] See Order dated August 1, 2017 in Docket No. E002/M-15-962 at page 5.

cost of such options, and whether these options are part of the Company's analysis in the Company's 2019-2028 Integrated Distribution Plan filed in Docket No. E002/CI-18-251.

As described in the Bus Voltage Sensitivity Analysis provided in our 2018 HCA small gains in hosting capacity can be seen by lowering the bus voltage for feeders constrained by overvoltage, but lowering the bus voltage in the field is not an option in most cases due to low voltage constraints. The theoretical gains are limited by the next violating threshold which cannot be improved upon by decreasing the bus voltage. For example, three of the five feeders that were studied ended up with low voltage violations after the over-voltage violation was mitigated by the reduction of bus voltage. This led to no hosting capacity gains for two of those feeders because the 2 percent bus voltage reduction was too large of a change.

Lowering the bus voltage without deeper grid visibility has the potential to lead to poor service quality for customers in the form of low voltage. Low voltage can cause customer equipment to malfunction or experience excessive current draw. Lowering existing bus voltages can also limit our operational flexibility. It inhibits our ability to transfer loads between feeders during maintenance or contingency situations. Lowering the bus voltage by itself is not a reliable solution. However, if this solution involves control combined with additional field assets to provide visibility and automatically maintain voltage when needed, this solution could be more reliable. This solution could potentially be fulfilled by IVVO functionality, which relies on AMI and ADMS installations.

As discussed in our IDP, IVVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices, or VAr control devices, that are dispersed across distribution feeders. IVVO is not currently one of the foundational advanced grid investments we are focused on, but it is a part of our advanced grid plans and supports our advanced grid aspirations to create value for customers and build new grid capabilities. There are important considerations involved in determining IVVO application on the system – some of which are technical, and others about maximizing value for customers. We are in the process of implementing IVVO in our Public Service of Colorado (PSCo) operating company affiliate. We believe there will be valuable lessons learned through that implementation that will benefit any further analysis of potential application or benefits in Minnesota.

## B. Load Profile Data

The Department also requested that the Company discuss the practicability of using more detailed load profile data in our feeder model and to file the peak load data by substation and feeder in spreadsheet format.

We currently do not forecast, or have the technological ability to efficiently forecast, detailed load profiles. While we are examining advanced planning tools to support an effort such as this (as described in our Integrated Distribution Plan filed in Docket No. E002/CI-18-251), we also have security and customer privacy concerns about providing this type of data. Specifically, we do not currently provide actual load data by substation and feeder publicly.

From a security perspective, we believe providing actual load data would provide a bad actor with the information necessary to target an attack on the grid where it would have maximum impact. In terms of customer privacy and confidentiality, we have looked to the Commission's decisions on customer Personally Identifiable Information (PII) and Customer Energy Usage Data (CEUD),[3] and believe we have a responsibility to protect customer anonymity. While grid and customer connection details are not directly implicated in that proceeding, the Commission directed utilities to look to NIST principles for guidance with regard to collection and protection of customer PII[4] – and required utilities to refrain from disclosing CEUD without customer consent unless the utility has adequately protected the customer's anonymity.[5]

While we provide a full list of specific feeders and their associated hosting capacity in our HCA report, we buffer and remove certain feeders from the heat map in an effort to protect what we believe is private or confidential customer data, and/or critical distribution infrastructure information. Providing detailed maps or actual load data by feeder could directly compromise grid security or customer privacy and security by revealing how customers are fed by the Company's electric facilities and in some cases, their CEUD. The maps or detailed actual load information could also be combined with other publicly-available information to re-engineer and compromise security and privacy.

As we have discussed, the issue of access and protection of distribution grid

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[3] Docket No. E,G999/CI-12-1344.

[4] *See* ORDER REQUIRING UTILITIES TO ADOPT AND DOCUMENT PROCESSES REGARDING PERSONALLY IDENTIFIABLE INFORMATION AND OTHER ACTION, Docket No. E,G999/CI-12-1344 (June 24, 2014) and as modified by the ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING RECONSIDERATION FOR LIMITED PURPOSE OF CLARIFYING AND MODIFYING LANGUAGE (September 9, 2014).

[5] *See* Order GOVERNING DISCLOSURE OF CUSTOMER ENERGY USE DATA TO THIRD PARTIES, REQUIRING FILING OF PRIVACY POLICIES AND COST DATA, AND SOLICITING COMMENT, Docket No. E,G999/CI-12-1344 (January 17, 2017).

information is largely uncharted territory today.[6] At the state level, the Commission has examined customer privacy and confidentiality in terms of Customer Energy Usage Data (CEUD) and customer Personally Identifiable Information (PII). At a national level, we have looked to guidance from the National Institute of Standards and Technology (NIST), North American Electric Reliability Corporation (NERC), and Federal Energy Regulatory Commission (FERC). We found that existing regulatory, legal, and industry frameworks provide little to no specific guidance with respect to data security protections and customer privacy and confidentiality considerations as it relates to distribution grid data. We considered these sources as advisory and developed criteria to apply to the visual hosting capacity results that would protect what we believe is sensitive and therefore non-public grid and customer information. In looking to NIST and other national standards that are generally applicable to the transmission grid, we found that they are broad and largely rely on utilities' judgement to apply them to their infrastructure.

We note that the Minnesota Government Data Practices Act (Minn. Stat. § 13.01 et seq.) addressing nonpublic data (Minn. Stat. § 13.02, subd. 9), private data on individuals (Minn. Stat. § 13.02, subd. 12), nonpublic data (Minn.Stat. § 13.02, subd. 9), security information (Minn. Stat. § 13.37, subd. 1(a)), and trade secret information (Minn. Stat. § 13.37, subd. 1(b)), is not directly applicable here. The Minnesota Government Data Practices Act only addresses information held by state government. Here, the Hosting Capacity map developed by the Company has been publicly filed and is intended to be a tool for the general public; there is therefore no Trade Secret or nonpublic version of this filed map on file with state government.

We believe our judgement that actual load information and the approach we applied to our heat map results are based on sound principles, and reasonably balance grid security, customer privacy, confidentiality, and energy security and public policy objectives. We are the first utility in Minnesota to encounter these privacy and security questions as they relate to hosting capacity. We are open to participating in a Commission proceeding that builds on the Commission's framework around PII and CEUD to include to examine grid-related security and privacy considerations.

## C. Constraints, Mitigations, and Costs

The Department requested that the Company provide a discussion about the feasibility and value of providing the following information:

- The frequency at which the constraints to individual feeders occur

[6] *See* Xcel Energy Reply Comments, Docket No. E999/CI-15-556 (September 21, 2017).

throughout the distribution system;

- A range of potential costs for each of the mitigation options available for an individual feeder and a range of total costs;
- How much additional hosting capacity could be obtained by implementing the identified mitigation options on a technical and economic basis (i.e. the technical potential of the mitigation options and the economic potential of the mitigation options); and
- Whether there would be a cost-effective impact on the value of DERs if such mitigation options were pursued (i.e. do any of the mitigation options impact the value proposition of DERs and if so, what is that impact?)

We respond to these questions below.

### 1. *Frequency of Constraints*

The frequency at which specific constraints occur throughout the system can be determined from Attachment A of our HCA. Every min and max limiting factor can be tallied to determine the frequency of a given violation for each feeder. We can certainly further summarize the data in future reports, but it is important to point out that the data is presently available in the tabular format that we make available on our website at: https://www.xcelenergy.com/working_with_us/how_to_interconnect

While we can sum up the number of times a constraint is reached in regard to the minimum and maximum hosting capacities in future reports, we note that the HCA is a locational tool and we believe this additional data may confuse the role of hosting capacity analysis.

As shown in our sensitivity analysis for both the variation in bus voltage and power factor, mitigating the limiting violation can often be followed by another violation for a different threshold. These new limiting thresholds may not provide significantly larger amounts of hosting capacity. So focusing on solving one violation can be misleading if the thought is that large amounts of hosting capacity will now be available. The level of hosting capacity gains for a particular feeder is dependent upon the unique characteristics of each feeder and may vary greatly.

Because certain mitigations can change hosting capacities for other thresholds, it can be misleading and confusing to list all hosting capacities by threshold violated if the intention is to look past the first hosting capacity threshold with an assumed mitigation. For instance, changing power factor to increase over-voltage hosting capacity can decrease hosting capacity for thermal overloads. This highlights the importance of a detailed interconnection study that looks at all aspects of the interconnection, including the ramifications of proposed mitigations in relation to other constraints on the system.

### *2. Mitigation Costs and Impact*

The potential range for mitigation costs and the related impacts are wide-ranging. Based on data from our Community Solar Garden program as detailed in the monthly status reports filed in that Docket, for what is typically a 1 MW to 5 MW DER site, the actual costs of mitigations combined with other interconnection costs have ranged from under $50,000 to over $1.4 million. The actual costs may depend on the extent of the constraint and the feeder, size and type of the proposed DER, proximity of the actual site of the specific DER to the substation[7], terrain, permitting issues, whether undergrounding is needed, whether winter construction is involved, and other factors. The range of the increased hosting capacity due to the mitigation is equally varying. Accordingly, we do not feel it would be a meaningful point of information since the costs and impact will vary so widely and are dependent on the individual circumstances.

With regard to the impact of the mitigation, based on the above, there would not be a way to provide a meaningful range or system point of data. Again, at this point of the process, the interconnection study is a much more applicable point of information since the additional hosting capacity gained is only to each feeder and the HCA is not a holistic system study.

### *3. Value of Mitigation Options for DER*

The Department requested the Company provide a discussion about the feasibility and value of providing information on whether there would be a cost-effective impact on the value of DERs if mitigation options were pursued. In doing so, the Department referenced its February 2, 2018 Comments in Docket No. E002/M-17-777. There, the Department noted that it appreciated the complexity and case-by-case engineering evaluation needed to inform the actual upgrades required to expand the hosting capacity.

Our 2018 HCA noted the following:

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[7] We believe that a large portion of the mitigation costs that have been applied to the Community Solar Garden program are for reconductoring. Where reconductoring is needed, it is applied for some portion of the feeder from the substation to the Point of Common Coupling for the DER. The exact distance will depend on the results of an engineering study.

- Feeder characteristics, distribution of DER, and size of DER can all create significant variability in hosting capacity and distribution upgrade costs.
- In general, voltage constraints are lower cost to mitigate due to the ability to adjust inverter settings.[8]
- Thermal overloads are generally more expensive to mitigate.
- Upgrade costs can be minimized by guiding systems to better locations.

These takeaways align with our potential mitigation strategies and further reiterate the difficulty in providing more detailed feeder specific mitigations due to the variabilities across the system.

Whether a specific mitigation has sufficient value to be performed is a decision that the DER owner needs to make. The DER owner will be informed of the initial required inverter settings, and will need to change these inverter settings as the requirements of the distribution system change. Further, if mitigations would include increasing the size of the transformers to address thermal overloads, or include reconductoring to accommodate the DER, the DER owner would be responsible for those costs.

We note that if these mitigations are made, they would be made only to allow the DER to be interconnected to the distribution system. If no DER were to be interconnected, then these costs would not be incurred. In this context, we do not see a value to performing the mitigations in the absence of accommodating the proposed DER. Since the DER would need to pay for these costs, it would be up to the DER to determine the value proposition to it for these costs. It would not be feasible, nor valuable, for us to do this assessment for the DER owner.

We also note that the front-end evaluation of costs and values will not always reflect future costs or negative values that may apply in the future to a specific DER. As discussed in the Distributed Generation Working Group (DGWG) in Docket No. 16-521, there may be certain future changes after a DER is placed in service that may impact the DER, such as the following:

Changes in Network Conditions: in this scenario, the DER system has been installed,

[8] Inverter settings such as non-unity fixed power factor are effective as a lower cost solution for certain feeder characteristics and DER penetration levels. Voltage constraints may need to be solved with relatively higher cost mitigations in the form of system upgrades (i.e. reconductoring overhead lines) if the inverter settings are not effective.

> interconnection costs have been paid, and the original engineering review determined capacity and costs based on an examination of minimum demand and load at that time. However, later the demand or load in the specific feeder or substation is significantly reduced (e.g., due to customers moving out or closing, Demand Side Management (DSM) efforts), which may mean that the network cannot provide appropriate service quality or reliable operation if the existing DER system(s) are in full operation. In this situation, it may be required that the DER system(s) are curtailed or disconnected until necessary network upgrades are made. This raises several questions, such as who should pay for the upgrades, how the curtailment should be allocated among DER systems, how lost production should be handled, and when the amount of expenses is too high to justify network upgrades.[9]

This highlights the difficulty of trying to identify with specificity an itemization of specified mitigations on a hosting capacity map, or even all specified mitigations in a detailed engineering pre-interconnection study for a specific DER system because some needed mitigations may only become known years after the DER is in commercial operation.

## D. Frequency of HCA Updates

The Department requested additional information regarding whether more frequent HCA map updates is feasible. Specifically:

- Why would the Company need to undertake a complete hosting capacity analysis each time it wanted to provide an update?
- Could an update be accomplished quarterly, or semi-annually?
- Can the Company perform a targeted update to the hosting capacity analysis (such as areas of the distribution system that are experiencing higher levels of interconnection than others and/or may have a higher locational value for DERs)?
- Is there a different hosting capacity analysis methodology that would be acceptable to the Commission and stakeholders that would make more frequent updates feasible?
- What is the cost to conduct the hosting capacity analysis such that the Company determined that more frequent updates has a cost that outweighs the benefit?

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[9] See, DGWG meeting notes for November 3, 2017 meeting, Docket No. E999/CI-16-521, at PDF page 36 of this link:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10F15560-0000-CD5A-8813-8E40DF6945DC}&documentTitle=201712-138167-03

As we have noted, we believe we may be at a critical juncture where the Commission may need to clarify or re-iterate the "starting point" objective of the HCA in the interconnection process, as it is a resource-intense initiative that would multiply in intensity if performed more than annually. We believe our HCA helps to streamline the interconnection process by assisting Developers in choosing sites that potentially require only screening or a less involved study, as intended by the statute. However, it is apparent from comments and as discussed in this Reply, some parties' expectations for the HCA are misaligned, and want or think it should supplant actual steps in Minnesota's standard interconnection process (or MN DIP).

If the Commission determines HCA should become part of MN DIP and as such, all utilities need to perform an HCA – among other considerations, it would be important for the Commission to the role of HCA in the standardized interconnection process along with other supporting details, such as update frequency.

That said, we respond to the Department's questions in relation to our current analysis. First, we believe a partial update is not practicable and would result in erroneous results. Today, our Geospatial Information System (GIS) provides the basis for the HCA and needs to tie the results to the system at a specific point in time. Both the results from the models and the GIS information need to correspond to that same point in time. If all of the models were first modeled in July, and then half were again modeled in January, there are changes that could and would occur on the other half of the feeders that would not be analyzed. This makes mapping difficult, because the point in time with which it needs to correspond/merge is now two time periods – and discrepancies will result.

Second, a more frequent update could not be accomplished with current staffing. It takes over 2,000 hours to complete the HCA on an annual basis, and this includes a heavy reliance on summer engineering intern resources. Even if we were able to determine some efficiencies with stakeholders and did not analyze the whole system every time, we do not believe we could get the time required for the HCA below 1,000 hours per update. That said, we can provide a more targeted analysis. However, as noted above, we run into mapping and resource challenges even with a more focused update. It may be worth noting that the same group performing this analysis is also the group most affected by the Integrated Distribution Plan (IDP), including NWA analysis, budget impacts, project scoring, reporting, etc., is also taking place simultaneously.

Third, changing methods or tools may not streamline or reduce the effort involved in HCA. We discussed and provided a comparison of the other hosting capacity methods currently employed across the country in our last annual HCA. As we noted, other methods employed by some utilities are actually *more* time consuming to run than DRIVE – and in all cases the bulk of the time is spent on ensuring the model is accurate and that it reflects reality as much as possible, so that part of the process would likely be the same regardless of the tool or methodology employed.

Finally, and perhaps most important – repeating an analysis for which parties do not agree on its value would distract Company and stakeholder resources from other priorities.

## E. Heat Map Display

The Department requested the Company indicate whether it is possible to use the same or similar software that allows Southern Cal Edison (SCE) to provide more detailed information – or, if the Company's current software can display such information. The Department also requested the Company discuss what options are available to better display the hosting capacity analysis and more detailed information that is valuable to developers and other stakeholders.

### *1. SCE Comparison*

SCE uses an Environmental Systems Research Institute (ESRI) mapping interface, just like we do.[10] However, SCE provides information that includes data for which we have security and customer privacy concerns over, as we have expressed and explained in past HCA filings. We again discuss these concerns in Part I.B. above.

That said, the data SCE provides can be broken into Substation, Feeder, and Circuit Levels and shows precise locations for each level data with the following data provided at each level:

Section Level

- Section IDs
- Node IDs
- Integrated (Hosting) Capacity

Circuit Level

- Feeder name
- Voltage Level

[10] ESRI is an international supplier GIS software, web GIS and geodatabase management applications.

- Substation Name
- System Name
- Existing Gen
- Queued Gen
- Total Gen
- Percent customer breakdown between Agriculture, Residential, Commercial, Industrial and other
- Min and Max Feeder Load Profiles by month

Substation Level

- Substation Name
- Substation ID
- System Name
- Existing Gen
- Queued Gen
- Total Gen
- Min and Max Substation Load Profiles by month

All this data is also downloadable and only pertains to the Integrated Capacity Analysis (hosting capacity). The maps have other layers that contain information on locational net benefit analysis, service territory, transmission circuits, and projected loads, among other things.

While we understand there is value in providing information on the hosting capacity map in the form of pop-ups there are also practical issues in identifying the correct information for the DER point of common coupling (PCC), which we discuss below.

### *2. Point of Common Coupling*

The PCC location, which is identified by the Developer, is key information when evaluating an interconnection using any of the available tools. The actual feeder chosen to evaluate interconnection will be the closest feeder to the Developer-defined PCC. There is a practical challenge associated with identifying the correct information for the PCC, given that we may have multiple feeders in the same area, and have limited areas where we have masked feeder details for privacy and security purposes. There are therefore various places on the map where a Developer could click on a location and instead of getting the specific information for the PCC, get a list of multiple feeders and associated data. Further, if the user of the hosting capacity map does not precisely select the correct position on the map, the information it returns would not align with the intended feeder and thus return a bad result.

Given these challenges and concerns, we believe it is best to use the hosting capacity map as a first step, and then move to the MN DIP pre-application screen to get actual information for the specified PCC.

## F. Minimum Daytime Load Information

We recognize the value Minimum Daytime Load (MDL) information has for evaluating DER impacts, and use actual MDL values on an as-needed basis. For HCA purposes however, it would be necessary to broadly gather actual MDL values for every feeder on an annual basis, which requires technical capabilities that we do not currently have – and would have an exponential impact on the resource-intensity of the HCA. We discuss these constraints further below, and note that we and other utilities are discussing with EPRI potential changes to the DRIVE tool that would allow for more efficient use of minimum load information in the HCA.

Fresh Energy asserted its belief that the Company's assumption for MDL is conservatively low, and that assuming a lower-than-actual daytime minimum load results in an exaggerated risk of reverse power flow at the substation feeder breaker and artificially low hosting capacity on the feeder. Fresh Energy also asserts its belief that as beneficial electrification accelerates, feeder MDL will increase, and recommends that the Commission require the Company to make the tracking and updating of actual feeder daytime minimum load a high priority in 2019 and include these values in its next HCA.

In order to accurately determine MDL values for a given feeder, we need Supervisory Control and Distribution Automation (SCADA) capabilities. As noted in our November 1, 2018 Integrated Distribution Plan filing in Docket No. E999/CI-18-251, today we have SCADA level load monitoring capabilities in approximately 61 percent of our Minnesota substations. While we have a long-term plan to add SCADA to our substations at a measured pace, we estimate equipping the remaining 39 percent of Minnesota substations with those SCADA capabilities would be in the range of approximately $30 to $40 million.

To broadly enable MDL for HCA purposes, once we have SCADA capabilities in all of our substations, we would need to determine the MDL for each feeder similar to the way we determine peak loads. This would involve reviewing historical MDL values by year and forecasting a value based on that historical view, plus any known changes or other growth assumptions. Our existing system planning software is not capable of helping determine these values, like it does for the peak load values. So, until the time we secure advanced planning software and capabilities, we would need to manually pull the raw data from the SCADA system for each of the feeders, analyze the data, then filter the values to only include daytime hours. At this time, it would be a labor-intensive manual process that may be improved upon in the future with additional software capabilities. At present, we estimate this part of the process of determining the MDL values for each feeder in Minnesota would take approximately 350 to 400 hours.

Currently, even though DRIVE performs the analysis feeder by feeder, we achieve efficiencies by grouping the process by substations, with individual feeder peak loads for each of the feeders attributed to that substation. Those peak loads are then reduced to 20 percent as part of the extraction process to also provide the minimum load case that is needed for the analysis. The current analysis involves 228 (total number of substations) extractions from Synergi (one of our distribution planning tools); we then we run 228 subsequent analyses using the DRIVE tool.

The optimal way to incorporate MDL into HCA would be to use actual MDL values for each feeder. However, we are not able to group MDL information like we can peak load information in the DRIVE tool. Therefore, to accurately reflect them in a minimum load model, we would need to re-run the analysis for every feeder at the minimum load level AND the maximum load level. The number of scenarios we would need to run in DRIVE would be effectively doubled. This would substantially increase the amount of time associated with this part of the process, which we estimate would be approximately 900 to 1,000 incremental hours. In total, after the substantial capital investment associated with SCADA capabilities, the incremental engineering time would be in the range of approximately 1,250 to 1,600 hours. As we have explained over time in our HCA proceedings, we believe our present approach to determining MDL for purposes of HCA is both reasonable and efficient at present. We are however, discussing with EPRI ways to more efficiently use minimum load information in the HCA that may also minimize the need for full system SCADA.

Finally with respect to beneficial electrification, it is too early to tell if MDL values will increase as electrification increases as Fresh Energy asserts. On one hand, more uses of electricity could certainly add to the MDL – but energy efficiency gains and more prevalent demand response could counteract those effects. Not to mention, nighttime charging of EVs, which is likely to be encouraged through rates and otherwise, would have no effect on the MDL.

We have discussed and considered the value of tracking and potentially forecasting MDL, and believe we will get there as our system and planning tools and capabilities advance – at which time, we may be able to add this to future HCA reports.

## G. The HCA is Not a Replacement for MN DIP Processes

Standardized process and technical requirements are crucial to streamlining interconnections. The Commission recently revised the Minnesota uniform statewide interconnection process standards. The revised standards, called the MN DIP, carefully define pre-application data, screening, and study processes. The standards do not involve, require, or rely-on hosting capacity maps from any utilities. Other states at the forefront of HCA, such as New York or California, have contemplated HCA in the context of a statewide effort in order to better coordinate with statewide interconnection standards. However, the MN DIP *precludes* the use of hosting capacity for technical screening without Commission action to make it part of the statewide standard. Therefore, the intended future use of the Company's HCA within the standard statewide process is unclear. Further, it is important to consider that narrowly focusing the hosting capacity tool and analysis on automating interconnection studies would actually limit the capabilities and use of the tool for other planning use cases.

With that context, we believe our HCA helps to streamline the interconnection process by assisting Developers in choosing sites that potentially require only screening or a less involved study, as intended by the statute. However, it is apparent from Fresh Energy's Comments that include Developer responses to a survey that Developers' – and Fresh Energy's – expectations for the HCA are misaligned in relation to the overall processes that comprise MN DIP.

For example, the accuracy expectations for the HCA contained in Fresh Energy's Comments are that it match the results from the pre-application data report ("capacity screens" for Solar Gardens). The pre-application data report simply provides existing system data; this is not an analysis, and does not offer capacity "results" per se, but instead provides an up-to-date snapshot of system information. It is unclear which pre-application data number is being considered the "result" by Fresh Energy.[11] In contrast, hosting capacity does run some preliminary analysis and provide an estimate of available capacity at a particular location. The tools are complementary and should not be viewed as interchangeable.

Figure 1 below shows how the different pieces of interconnection processing

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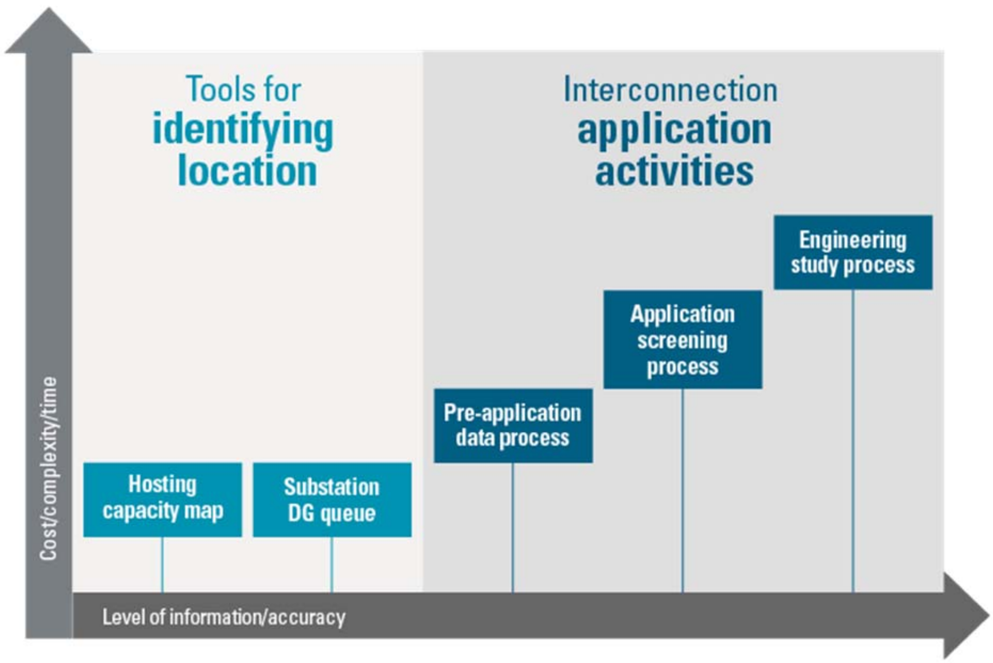
[11] In the past, some developers have conflated remaining substation transformer capacity (i.e. nameplate rating + MDL) listed on the pre-application report to be an actual hosting capacity number. In this case, the transformer information shows a thermal limit in the substation, but there may be other voltage, protection, or thermal limits downstream.

currently work. The lower cost and complexity[12] options of hosting capacity and pre-application data provide information Developers can use to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.

**Figure 1: Xcel Energy DER Interconnection Tools and Processes**




The hosting capacity map display is a high level estimate of the available hosting capacity for adding DER in a given general location. The determination of the amount of DER that can be accommodated at a point in the distribution system can include several steps, with more specific and more accurate information becoming available as the effort and expense to provide that more specific information increases.

The hosting capacity map and tabular data is offered free of charge and correspondingly, cannot be expected to be as accurate as further MN DIP application steps for obtaining more specific information. Also, the map is based on data as of a point in time and is not intended to be a substitute for the established interconnection process. A detailed engineering impact study determines the exact amount of generation that can be accommodated at a given location, as well as the mitigations required to interconnect the proposed DER project.

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[12] The relative cost and complexity is considered on a per node basis in Figure 1

More informative and site-specific information  on hosting capacity (applicable to applications that are not subject to the MN DIP) is offered in the following order:

1. Information on other projects in the interconnection queue for various feeders, but not yet interconnected, may have an impact on hosting capacity. This information is not reflected in the maps because we lack certainty on whether the projects will proceed. Individuals and Developers may use this information in conjunction with the hosting capacity maps and with the pre-application data request step outlined below. The interconnection queue information is available online under the Substation DG Queue prompt on this page.
2. Individuals and Developers may make a pre-application data request for a "Capacity Screen" for a specific location (as set forth in our Minnesota Section 9 Tariff at sheets 68.13 – 68.14). The current fee for a Capacity Screen is $250.00. For more information about obtaining a Capacity Screen, see the discussion about Capacity Screen Requests on this page. The MN DIP includes a similar pre-application data request.
3. Individuals and Developers may submit a formal request for interconnection at a specific site. For more information on submitting a formal request for interconnection see this page. After the Application is determined to be complete, and the applicable fees are paid, we will perform any necessary screening or study specific to that location and generation size and type – and where applicable, offer an Interconnection Agreement under our applicable tariffs. If a study is required, and Xcel Energy system modifications are found to be necessary, the study results will contain an indicative cost estimate for our work in building out our system to accommodate your distributed generation. Smaller-sized systems typically do not need these studies or system modifications.[13]
4. After the Section 10 Interconnection Agreement is signed and funded, and if system modifications are required, the Company will perform a detailed engineering design cost study with a more specific estimate of the Company's costs to build out the system to accommodate the interconnection. Individuals and Developers have the opportunity to cancel the Interconnection Agreement before the Company starts to do the build-out and before it starts to incur significant costs. Individuals and Developers will however, be responsible for the actual costs incurred by the Company.

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[13] If the DG system is under 250 kW and not subject to other restrictions, the Uniform Statewide Agreement in our Section 9 tariff may be used in lieu of the Section 10 Interconnection Agreement.

We summarize the various processes further below, applicable to any application that has not been submitted by June 17, 2019 and therefore would be governed by the MN DIP:

*Pre-application Data Process.* Customers and Developers may request a pre-application data report before formally submitting an application. For a fee, we can provide a snapshot of interconnection activity and system information at the requested location. The pre-application data report is not a guarantee of available capacity, but does offer some insight into whether our existing infrastructure can support proposed generation. These reports are generally helpful for larger generators. Small residential rooftop systems typically do not benefit from the pre-application data report. This is further detailed in our proposed tariff revisions to implement the MN DIP, in Docket No. E002/M-18-714, at proposed Sheets10-172 – 10-173 and 10-211 – 10-212.

*Application Screening Process.* Once received, an application must first be deemed complete. This means a high level review indicated all necessary information is in hand and we can provide meaningful feedback. If the type and size of the generation is eligible for screening, the interconnection request is checked against several broad screening criteria. If the site passes all checks, the request can bypass the full engineering study process and proceed directly to an interconnection agreement. Failure of any screening criterion does not automatically disqualify the site from being able to interconnect. However, it typically means that a more detailed engineering analysis is needed. Sometimes a screen failure can be addressed with a known mitigation and estimate without requiring a detailed study. This is further discussed in our proposed tariff revisions to implement the MN DIP, in Docket No. E002/M-18-714, at proposed Sheet 10-178.

*Engineering Study Process.* Detailed engineering review of a proposed interconnection requires use of specialized software and coordination between many of our workgroups and information databases. Multiple interconnections on a single distribution feeder are analyzed in order based on queue position. The engineering study will determine whether any physical upgrades and changes to our distribution system are required for the proposed generation to safely interconnect while ensuring safe, reliable, quality power for all customers on the circuit. Additional information on engineering studies is contained in our proposed tariff revisions to implement the MN DIP in Docket No. E002/M-18-714, beginning at proposed Sheet 10-181.

Screening is less expensive than engineering studies and typically can be completed on a shorter timeline. The "capacity screen" data, often referred to pre-application data in the industry (and in the MN DIP) is not to be confused with technical screening, provides the feeder name for a particular location which can be looked up in the hosting capacity table. The pre-application data also contains other useful up-to-date information about the location.

If the Commission determines that automating the interconnection process is an objective, we view one of the first logical steps as achieving a level of accuracy for the hosting capacity tool that allows using the results in place of technical screens, including the initial and supplemental review found in the MN DIP process. It is unclear at this time if an additional objective should be to fully automate the interconnection study process, given that commercially available modeling software is at the nascent stages of development regarding fully automating the study DER impacts. Furthermore, it is possible that selecting a hosting capacity tool with a narrow focus on automating studies actually limits capabilities of the tool for other planning use cases.

While it may be technically possible to automate power flow to the same level that is currently seen in interconnection studies, as was shown in the California working group, it is unclear if the results would represent an optimized solution that allows for the overall greatest amount of hosting capacity. For example, a detailed interconnection study will model different inverter settings to determine if voltage impacts can be mitigated. The process includes tuning existing inverter settings; the number of scenarios becomes quite numerous if approached in an iterative nature. The engineer will also determine the least cost option for system modifications if required to mitigate voltage impacts. Furthermore, the level of costs associated with the type of more computationally intensive and complex effort in California is unclear. This would be important information when considering the value proposition in our Minnesota service area.

In the longer term, we share the goal that many parties have of further automating the interconnection process. However, DRIVE alone will not create a streamlined interconnection process. The tool is only a part of the solution to streamlining the process, not the whole. As was seen in California, PG&E suggested a tiered approach for interconnection tools[14] that matches the tiered approach of the state's Rule 21 interconnection process. In a recent study, San Diego Gas and Electric recommended a blended approach[15] for planning use cases due to computational limitations associated with the iterative method. The California experience, coupled with New York utilities choosing an alternate route, makes clear that no single industry direction has emerged. We are closely watching the hosting capacity and automated interconnection developments in the industry in order to adopt the right

[14] California Distribution Resources Plan (R.14-08-013), Integrated Capacity Analysis Working Group, Final ICA WG Report, March 15, 2017

[15] SDG&E DRP Demonstration A – Enhanced Integration Capacity Analysis, December 2016

tools at the speed of value. We are also continuing to work with EPRI and others in the industry on best practices as HCA and interconnection processes and tools continue to evolve.

## H. Department Recommendations

The Department recommended the Commission require the following in future reports: (1) Updates on the appropriateness of the methodological choice of the hosting capacity analysis, a discussion of the Company's ability to obtain more detailed secondary voltage equipment data, and the types of DER being interconnected; (2) Updates on the evolving capabilities of the DRIVE tool and its capabilities of incorporating technologies included in the broadened definition of DER, and (3) Work with stakeholders to improve the value of the HCA, including but not limited to the provision of more detailed substation, feeder, and other equipment data in the hosting capacity map.

### *1. Methodological Choices, Secondary Voltage Data, and Types of Connected DER*

We accept this recommendation, and will provide discussion on our methodological choices and on the subject of secondary voltage data in our 2019 HCA report. Regarding the types of DER currently on the system, this information is provided by all utilities in annual March 1 filings in Docket No. E999/PR-[YEAR]-10. We are happy to include a link to eDockets to our filed information in our 2019 HCA report.

### *2. Ongoing Updates on DRIVE capabilities*

We continue to work collaboratively with EPRI and monitor the industry in terms of hosting capacity analyses, and are committed to provide the Commission and stakeholders updates on the EPRI DRIVE tool and its capabilities in relation to the industry. We understand 'broadened definition of DER" in the context of this recommendation to include energy storage, as discussed on pages 14-15 of the Department's Comments. As committed in our HCA, we are committed to monitor DRIVE's capabilities with regard to energy storage and maximize its capabilities where we can.

### *3. Incorporate Stakeholder Feedback and Consider Providing More Detailed Data in the Heat Map*

We are always happy to engage with stakeholders toward ensuring the HCA provides value. However as discussed further in these comments, in addition to data security and privacy concerns associated with providing more detailed data in the heat map as discussed in Part I.B. above, there are also issues in identifying the correct information for the PCC as discussed in Part I.E. above. We are committed to monitoring, learning, and continuing to evolve and improve our HCA as the industry continues to undergo change. We will continue to assess ways to enhance the heat map to increase its value as a precursor to the interconnection process.

## CONCLUSION

We appreciate the opportunity to provide these Reply Comments. We are committed to monitoring, learning, and continuing to evolve and improve our HCA as the industry continues to advance.

Dated: March 28, 2019

Northern States Power Company

# CERTIFICATE OF SERVICE

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

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

xx electronic filing

**Docket No. E002/M-13-867**

Dated this 28th day of March 2019

/s/

______________________________

Jim Erickson
Regulatory Administrator

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