UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	Docket No. RM21-17-000

INITIAL COMMENTS OF ENVIRONMENTAL AND RENEWABLE ENERGY ADVOCATES

On July 15, 2021, the Federal Energy Regulatory Commission (FERC or Commission) issued an Advance Notice of Proposed Rulemaking (ANOPR) seeking comments on its proposal to make changes to regional transmission planning, regional cost allocation, and generation interconnection processes.[1] The Commission proposes to significantly change transmission planning, cost allocation, and interconnection by moving away from today's largely piecemeal planning process toward more holistic, economically-efficient processes that are forward-looking about the future needs of the grid. The Commission's proposed changes across a broad range of transmission rules and requirements would radically change the way that Regional Transmission Organizations and Independent System Operators (RTOs/ISOs) and other transmission planners plan and pay for the grid.

The Center for Renewables Integration, Defenders of Wildlife, Environmental Law & Policy Center, National Audubon Society, National Wildlife Federation, and Vote Solar (collectively, Commentors) support the general direction the Commission proposes in the ANOPR. The following comments raise additional considerations regarding how to better

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 175 FERC ¶ 61,035 (2021) (ANOPR).

account for siting concerns earlier in the planning process and how to better consider where advanced transmission technologies (ATTs) can allow for faster, cheaper grid enhancements with fewer environmental impacts. We ask that the Commission develop a notice of proposed rulemaking that incorporates the suggestions and concerns raised in these comments to ensure that the transmission planning and generator interconnection processes under the Commission's jurisdiction are just, reasonable, and not unduly discriminatory.

I. Transmission siting must become a part of the transmission planning process.

The siting of transmission lines is often contentious and significantly increases the cost of transmission projects while reducing the likelihood that a previously approved project will ever go in-service.[2] By excluding considerations of the costs and risks associated with transmission siting in the transmission planning process, RTOs/ISOs and other transmission planners are unable to fully consider the costs and benefits of proposed projects. The Commission should require transmission planners to develop a formal process that uses stakeholder feedback on potential siting concerns to better evaluate the costs and benefits of proposed projects, and to do so early in the planning process to avoid delays and setbacks later. The Commission should ensure that including siting in the planning phase is not a source of added delay to the process. The goal of including siting early in the process is to reduce unnecessary friction downstream, not to add more.

[2] *See* Staff of the Federal Energy Regulatory Commission, *Report on Barriers and Opportunities for High Voltage Transmission*, 21-22 (2020) (identifying state and federal "permitting regimes" as a barrier to high voltage transmission), *available at* https://cleanenergygrid.org/wp-content/uploads/2020/08/Report-to-Congress-on-High-Voltage-Transmission_17June2020-002.pdf

A. The current lack of siting considerations in transmission planning leads to unnecessary delay and to unjust and unreasonable rates.

Transmission planning, particularly at the RTO/ISO level, is largely ignorant to siting realities. Transmission planners identify substation connections and voltages necessary to resolve reliability, economic, or public policy constraints and then draw lines between substations to determine preliminary siting. The true cost and complexity of siting, however, is not typically considered in the evaluation of projects.

In the PJM Interconnection (PJM), for example, Manual 14B for the transmission planning process includes a single sentence stating: "An independent consultant **may** be used to develop an independent cost estimate and evaluate the **constructability** of proposed solutions."[3] This optional independent consultant analysis is mentioned only once in the 164-page manual, alongside a planning cycle exhibit that does not even use the same language, choosing instead to use the word "buildability."[4] These terms are undefined in the manual. Is constructability/buildability merely referring to the technical feasibility of construction across terrain, or does it include potential feasibility issues such as delays and added costs due to environmental siting concerns? PJM's manuals are silent and do not provide meaningful consideration of siting at the planning stage.

In the Midcontinent Independent System Operator (MISO), transmission siting feasibility, constructability, and buildability are absent from the transmission planning process altogether. MISO uses an annually updated Transmission Cost Estimation Guide to develop cost estimates and derive benefit-to-cost ratios for transmission solutions in the MISO Transmission

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[3] PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 49, 35 (June 23, 2021) (emphasis added).

[4] *Id.* at Exhibit 1, 34.

Expansion Plan (MTEP). However, siting concerns are largely absent from this cost estimation process. The cost of construction is driven by the straight-line mileage between substations with a generic percentage adder added to account for the realities of wire placement along that general route.[5] The estimate makes no attempt to account for costs added by delays or even denials based on environmental, cultural, and other land use impacts that are only revealed in the state and federal approval processes.

The Commission does not currently require RTOs/ISOs to consider transmission siting realities that may have a material impact on the cost or even viability of proposed transmission projects. Yet the difficulty of overcoming the siting hurdles of transmission projects is very real.[6] Concerns about the state-by-state siting process have led some observers to call for expanded federal authority over siting.[7] Commentors take no position on the expansion of federal siting

[5] *See e.g.* Draft Transmission Cost Estimation Guide MTEP20 (Feb. 11, 2020), *available at* https://cdn.misoenergy.org/20200211%20PSC%20Item%2005c%20Cost%20Estimation%20Guide%20for%20MTEP20%20DRAFT%20Redline425617.pdf

[6] *See* Staff of the Federal Energy Regulatory Commission, *Report on Barriers and Opportunities for High Voltage Transmission* at 21-22; Joseph H. Eto, Laurence Berkeley National Laboratory, *Building Electric Transmission Lines: A Review of Recent Transmission Projects*, vii (2016) (concluding that a major commercial risk for transmission projects is "the cost of satisfying the due process requirements of state and federal agencies involved in permitting and siting lines, which is often increased when there is organized public opposition to the project."), *available at* https://eta-publications.lbl.gov/sites/default/files/lbnl-1006330.pdf

[7] *See e.g.* Avi Zevin, Sam Walsh, Justin Gundlach, Isabel Carey, Columbia Center on Global Energy Policy and Institute for Policy Integrity, *Building a New Grid Without New Legislation: A Path to Revitalizing Federal Transmission Authorities* (Dec. 2020), *available at* https://energypolicy.columbia.edu/sites/default/files/file-uploads/GridAuthority_CGEP_Report_121120-2.pdf; Robinson Meye, *Unfortunately, I Care About Power Lines Now*, The Atlantic (July 28, 2021) (arguing in favor of legislation that would expand federal siting authority), *available at* https://www.theatlantic.com/science/archive/2021/07/america-is-bad-at-building-power-lines-lets-fix-that-transmission-climate/619591/

authority in these comments. Even if the Commission took on an expanded backstop authority, however, consideration of siting in the planning process would still be important. We urge the Commission to use its existing authorities to require RTOs/ISOs and other transmission planners to consider siting in the transmission planning process. Such requirements would not interfere with existing state siting authority; states would retain their rights to make final siting determinations. In practice, bringing siting into the transmission planning process could streamline the state approval process by addressing difficult siting concerns early in the process before conflicts arise between projects selected for market/reliability/resiliency/public policy needs and siting issues at the local level.

For example, imagine that an RTO/ISO is faced with resolving a transmission constraint with two possible solutions. On paper, Solution A has a higher benefit to cost ratio than Solution B and the RTO therefore selects Solution A. When Solution A goes to state and federal siting approval, however, it becomes clear that there are significant environmental, cultural, and other land use concerns with the route required by the substation connections selected by the RTO/ISO. These siting concerns lead to significant delay in approval of solution A and jeopardize the project. Solution B, however, while having a lower benefit to cost ratio under the current planning process, does not have the same siting concerns, whether due to a difference in substation locations, line milage, or technology such as advanced transmission solutions. Solution B would have had a much smoother state siting approval process and would not be in danger of being abandoned altogether due to siting concerns. This difference in siting viability may have materially changed the benefit to cost analysis of the two solutions and demonstrated that Solution B would ultimately require less time and money. Under the Commission's current transmission planning requirements, however, there is simply no way to know.

It is important for the Commission to recognize that increased project siting costs are not the only costs at risk in the current regime. Commentors are strong supporters of renewable energy and recognize that our electric distribution and transmission grids must be transformed to achieve our climate goals. This will require large investments in ATTs and new transmission infrastructure to optimize and accelerate renewables deployment. Delay of needed transmission investments present a considerable hurdle to these climate goals. Delayed transmission investment and ATT deployment also means delayed savings on transmission, energy, and capacity costs, as well as continued reliance on fossil generation. Handling siting concerns early in the transmission process will lead to faster in-service dates for vital infrastructure, bringing with it lower costs, increased reliability/resilience, and progress toward public policy goals.

The lack of transparency into the potential increased cost, time, and risk of failure for a transmission project during the planning stage leads to unjust and unreasonable rates. Transmission projects cost more due to changes in routes, increased administrative costs, delayed in-service dates, and at times outright cancelation of projects. The Commission must take steps to reduce the risks in the siting approval process by introducing siting issues into the early stages of planning.

B. The Commission has the authority to require transmission planners to consider siting in their evaluation of alternatives in the transmission planning process.

Under the current regulatory regime, transmission developers are required to receive a certificate of public convenience and necessity, or a similar permit, to construct and operate transmission line projects within a state.[8] Similarly, transmission developers are often required to

[8] *See* Staff of the Federal Energy Regulatory Commission, *Report on Barriers and Opportunities for High Voltage Transmission* at 21.

get permits from relevant federal agencies.[9] While the Commission may not always be willing or able to usurp state authority over siting, the Commission is still required to ensure just and reasonable rates.[10]

The lack of consideration of the costs and risks of siting in the transmission planning process increases the cost of transmission and can therefore prevent just and reasonable rates. There is no prohibition in federal or state law preventing transmission planners from factoring likely transmission siting costs into their cost-benefit analyses just as they would any other anticipated costs of construction. Nor does requiring RTOs/ISOs and other transmission planning authorities to examine the potential siting difficulties of proposed transmission projects intrude on state authority. On the contrary: taking siting considerations into account during the transmission planning process would lead to more accurate cost-benefit analyses and would enhance rather than detract from state authority.

Today, states are often put in the difficult position of being told by transmission planners on the one hand that a project is necessary for reliability, economic, or public policy reasons but by environmental or other stakeholders on the other hand that a project's siting requirements make it untenable. The state siting authority, then, is left to decide between often-conflicting priorities. If, however, major siting concerns with the potential to derail or significantly increase the cost of a project were considered in the planning process and weighed against viable alternatives with fewer or less severe siting concerns, states would be able to more accurately assess the siting concerns versus the grid and other benefits of a proposed project. In other

[9] Joseph H. Eto, Laurence Berkeley National Laboratory, *Building Electric Transmission Lines: A Review of Recent Transmission Projects*, at v.

[10] 16 U.S.C. 824e. Section 206 requires that transmission rates be just and reasonable.

words, state siting decisions would be on firmer ground because those decisions would have the benefit of an apples-to-apples comparison of the costs and benefits of a project seeking approval.

C. The Commission should require transmission planners to implement a robust stakeholder process that allows for consideration of transmission siting costs in the cost-benefit analysis of proposed projects.

The Commission has an obligation to ensure that transmission planners are taking siting concerns into account during the transmission planning process to ensure a proper accounting of the costs and benefits of projects. The Commentors propose that the Commission issue a NOPR that includes a requirement that transmission planners, including RTOs/ISOs, create rules and procedures that allow stakeholders to discuss siting considerations in the planning process. In so doing, transmission planners should develop a process by which the various costs and risks of transmission siting factor into the cost-benefit analysis of proposed projects.

The goal of requiring consideration of siting is not to burden the planning process with increased bureaucracy. Commentors believe that raising siting issues as early in the process as possible will reduce the net burden on transmission projects rather than increase it. While there is no expectation that such a process will eliminate conflicts over siting at the state and federal level entirely, addressing the issue early in the process to potentially avoid the largest and most destructive siting issues should yield better results at the state and federal level. This vetting of siting early will reduce the expected costs of transmission projects more broadly while allowing for faster approval and construction of transmission projects necessary to increase penetration of renewable energy and maintain grid reliability and resilience at least cost.

Neither the Commission nor the transmission planner need to reinvent the wheel to make siting a part of the planning process. Many groups, including some of the undersigned Commentors, have been advocating for integration of siting in the planning stage of renewable and transmission planning for the past decade. Sometimes called Smart from the Start, environmental advocates have developed criteria and policies for how to integrate siting into the planning process.[11] Integrating siting considerations into planning may include:

- Early identification of and consultation with stakeholders to encourage them to raise potential siting issues early in the planning process.
- Collecting and using geospatial information to categorize the risk of siting conflicts.
- Avoiding land and wildlife conservation conflicts and prioritizing development in previously disturbed areas.
- Avoiding cultural resource conflicts.
- Maximizing the use of existing infrastructure and rights-of-way, and undergrounding transmission lines whenever economically and logistically feasible.

Transmission planners can use these principles in their project selection criteria. Where possible, this process should yield quantifiable input that will help planners conduct a cost-benefit analysis to find the least-cost solution to transmission needs.

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[11] *See,* Carl Zichella and Jonathan Hladik, *Siting: Finding a Home for Renewable Energy Transmission*, in America's Power Plan at pp. 9-10 (2013), *available at* https://www.energy.gov/sites/prod/files/2015/03/f20/APP-SITING-PAPER.pdf; Comments of the Natural Resources Defense Council (NRDC), The Wilderness Society, National Audubon Society and Defenders of Wildlife on the U.S. Department of Energy Request for Information Improving Performance of Federal Permitting and Review of Infrastructure Projects Integrated Interagency Pre-application Process (IIP) For Significant Onshore Transmission Projects Requiring Federal Authorization (October 30, 2013) (arguing for consideration of siting impacts in the integrated interagency pre-application process for non-RTO transmission projects), *available at* https://www.energy.gov/sites/prod/files/2013/10/f4/Comments_RFI-IIP_NRDC.pdf

D. Early identification of siting concerns should be a part of any renewable resource zone requirement.

The Commission seeks comment on whether it should require transmission providers in each transmission planning region to establish a process to identify geographic zones that have the potential for development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable energy resources in those zones.[12] If the Commission chooses to adopt some form of renewable resource zone requirement, it should require transmission planning authorities to include siting in any zonal development process. As described above and as members of Commentors have urged elsewhere, early and realistic assessments of siting issues is important to efficiently and cost-effectively achieve our clean energy goals.

E. The Commission should use the Office of Public Participation and the Joint Federal-State Task Force on Electric Transmission to identify best practices for including siting in the transmission planning process.

Commentors urge the Commission to leverage the newly established FERC Office of Public Participation (OPP) and the Joint Federal-State Task Force on Electric Transmission (Task Force) to help guide the integration of siting in the planning process. These two bodies are uniquely situated to help facilitate the interactions between organizations and individuals who typically do not engage directly in FERC-authorized transmission planning – including some of the undersigned commentors - and the complex transmission planning process. This is especially true for the RTO/ISO transmission planning process, which historically is difficult to navigate even for subject matter experts. The Commission should seek input from the OPP and the Task

[12] ANOPR at P 54.

Force in this rulemaking to develop best practices for including siting in the transmission planning process.

II. Advanced transmission technologies, including grid-enhancing technologies, must become a part of the transmission planning process.

The Commission rightly recognizes the need to modernize transmission planning, cost allocation, and interconnection as we transition to a grid dominated by renewable resources. As Chairman Glick and Commissioner Clements articulated in their concurrence, "the transmission needs of the electricity grid of the future are going to look very different than those of the electricity grid of the past."[13] As renewable energy expands nationwide, we need a robust, efficient, and modern electricity delivery network to match and a planning process that looks forward to the needs of the grid in coming years. The Commission asks if and how Grid-Enhancing Technologies (GETs) should be accounted for in the transmission planning process.[14] Commentors believe that transmission planners must fully consider ATTs – including GETs –in the transmission planning process.

Commentors recognize and support the need for new transmission lines to be a part of the solution, especially regional high voltage lines designed to maximize delivery of renewable energy to load. However, high-voltage transmission lines are not the solution to all problems and are not appropriate in all places. Even under the best circumstances, traditional wires-based solutions are expensive and take a long time to approve and construct.[15] Therefore, we ask the

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[13] *Id.*, Glick and Clements concurring, P 1.

[14] ANOPR at P 48.

[15] *See* Transmission Agency of Northern California, Transmission Q&A ("On average it can take 10 years or more to build a high-voltage transmission line."), *available at https://www.tanc.us/understanding-transmission/transmission-qanda/* (last accessed Oct 12, 2021).

Commission to require a full and fair treatment of ATTs, including GETs, in the transmission planning process. These technologies are often low-cost, have significantly fewer siting concerns than large wires projects, and can be placed in service in a matter of months rather than years. By enhancing the performance of our existing transmission system with smart technology, we can maximize clean energy investments, reduce carbon pollution, and improve reliability.

Commentors take an expansive definition of ATTs to include not only the technologies already identified as GETs by the Commission (e.g., power flow control and transmission switching equipment, storage technologies, and advanced line rating management technologies), but also aggregated distributed energy resources (DERs), local generation, and combinations of all these technologies into a suite of solutions that can better utilize existing transmission infrastructure. We urge the Commission to require transmission planners to place ATTs on a level playing field in the transmission planning process.

A. The current lack of advanced transmission technologies in transmission planning leads to unjust and unreasonable rates and lowers grid resiliency.

Congress and the Commission have long recognized the value of ATTs to the grid. The Commission summarized this value in Order 890:

> Through EPAct 2005 sec. 1223, Congress also directed the Commission to encourage the deployment of advanced transmission technologies in infrastructure improvements, including among others optimized transmission line configurations (including multiple phased transmission lines), controllable load, distributed generation (including PV, fuel cells and microturbines), and enhanced power device monitoring. Accordingly, each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated regional planning process that complies with the planning principles and other requirements in this Final Rule.[16]

[16] *Preventing Undue Discrimination and Preference in Transmission Service*, Order 890, 118 FERC ¶ 61,119, PP 436-437 (2007) (Order 890).

Despite the Commission's requirement in Order 890 for ATTs to be a part of the transmission planning and selection process, in many instances these technologies go unexplored. This lack of comparable treatment stems from lack of information available to ATT developers, lack of sufficient time in which to propose ATTs as cost-effective solutions to identified transmission needs, processes that prevent ATT developers/owners from proposing alternative solutions, and a lack of competition for the local projects that now dominate the planning process.

1. Lack of information creates a barrier for advanced transmission technology developers/owners to meaningfully participate in the transmission planning process.

Lack of information is a significant barrier to the development of ATTs. In most infrastructure-dependent industries, we consider utilization of fixed cost capital assets a measure of efficiency. Yet the current transmission industry receives no such scrutiny. Transmission owners are not required to evaluate the efficiency of their transmission systems beyond identifying areas of constraint under certain conditions.

Under the existing planning regime, there is no consistent source of information on the utilization rate of existing grid infrastructure. According to the Department of Energy's (DOE) 2020 Congestion Study, "A national assessment of individual transmission constraints is not possible because of the limited amount of information that is publicly available."[17] In its most recent Annual U.S. Transmission Data Review from 2018, the DOE similarly had to cobble

[17] U.S. Department of Energy, *2020 Congestion Study*,11 (Sep. 2020), *available at* https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf.

together various data points from across the country in an effort to provide some insight into utilization.[18]

What little information exists suggests that utilization is low. For example, a simulation presented to the Commission in 2019 by Apex Clean Energy found that 85 percent of transmission lines had a loading factor of less than 20 percent in PJM and Eastern MISO, with more than 1,200 facilities in PJM alone with loading factors under 20 percent.[19] In the Western Electricity Coordinating Council, data from 2016 similarly indicated very low congestion for most major transmission paths.[20] As further evidence that utilization information is generally unavailable, the DOE noted in its 2020 report that "[c]omparable information does not exist on the operation of the transmission system across the Eastern Interconnection."[21]

Commentors do not present evidence of low utilization rates to suggest that there are no congestion problems on the transmission system or that new infrastructure is not needed to connect generation to load. Rather, ATTs can be a way to increase the utilization of our existing infrastructure to get more out of what we have already built. As Apex Clean Energy explained to the Commission, the level of underutilized existing infrastructure suggests that ATTs might play

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[18] U.S. Department of Energy, *Annual U.S. Transmission Data Review*, 21-26 (Mar. 2018)*, available at* https://www.energy.gov/sites/prod/files/2018/03/f49/2018%20Transmission%20Data%20Review%20FINAL.pdf.

[19] Transcript of Day 1 of the Nov. 5-6, 2019 Grid-Enhancing Technologies Workshop, FERC Docket No. AD19-19-000, 23-24.

[20] U.S. Department of Energy, *2020 Congestion Study* at 11-12.

[21] U.S. Department of Energy, *2020 Congestion Study*, 12 (Sep. 2020), *available at* https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf.

a substantial role in enhancing the "flexibility and resiliency of the grid while maintaining system reliability."[22]

The lack of available robust utilization data, however, means that ATT developers do not know where best to target projects. They cannot be sufficiently proactive in locating areas of the grid where their technologies could be of highest value to the grid, and therefore we see fewer ATT projects of all stripes than we should. This in turn unjustly and unreasonably raises transmission rates because transmission planners are unable see all the viable solutions to any given transmission need.

2. Current planning processes rely on piecemeal and just-in-time projects that avoid competition from advanced transmission technologies.

The current transmission planning regime relies too often on just-in-time transmission projects with no competition from ATT developers or other transmission providers. In response to Order 1000's narrowing of the right of first refusal for regional projects, transmission owners have over the past decade moved away from regional transmission projects subject to competition toward a focus on projects that are not subject to competition.[23] In PJM, this can be seen in the rise in "supplemental" project costs from $3 million in 2013 to $3.9 billion in 2020.[24] Supplemental projects are defined in PJM as "a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational

[22] Transcript of Day 1 of the Nov. 5-6, FERC Docket No. AD19-19-000 at 23.

[23] *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, Energy Law Journal Vol. 42:1, 50 (2021), *available at* https://www.eba-net.org/assets/1/6/5_-_%5bPeskoe%5d%5b1-66%5d.pdf

[24] *See* Consumer Advocates of the PJM States, Letter to PJM Board of Managers (Sep 16, 2019), *available at* https://0201.nccdn.net/1_2/000/000/199/214/CAPS.Supplemental-Project-study-and-conclusions.9.16.2019.pdf

performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project."[25] They are, at heart, projects planned by Transmission Owners and not subject to competition. In 2019, supplemental projects accounted for 70 percent of transmission projects in PJM.[26]

MISO has seen a similar rise in non-competitive projects in the form of "other" projects. Other projects in MISO are like PJM's supplemental projects and are defined as transmission projects that "do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects."[27] Other projects accounted for 67 percent of all MISO transmission projects in 2020.[28]

The naming conventions of "other" and "supplemental" projects alone should give the Commission pause. Projects can hardly be considered "supplemental" or "other" when they make up 70 percent of an RTO/ISO's annual transmission investment. Beyond the sheer quantity, however, the fact that transmission owners are pouring investment into these projects raises significant questions about just and reasonable rates. As the Consumer Advocates of the PJM States noted in their letter to the PJM Board of Managers, Continuum Associates found a

[25] PJM Transmission Owners Attachment M-3 Process Guidelines Version 0.1 (Oct 4, 2019), *available at* https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx?la=en

[26] *See* PJM Transmission Expansion Advisory Committee, 2019 Project Statistics, 3 (May 12, 2020), *available at* https://www.pjm.com/-/media/committees-groups/committees/teac/2020/20200512/20200512-item-10-2019-project-statistics.ashx

[27] MISO MTEP 2020 Final Report, 16, *available at* https://cdn.misoenergy.org/MTEP20580492.zip.

[28] *Id.*

general lack of transparency and consistency in the supplemental project planning process.[29] MISO itself has argued that changes to its "Local" projects (which includes "other" projects) would "Allow[] interested parties to identify and plan alternatives for Local projects that may be considered for Appendix A in a future MTEP cycle".[30]

This lack of transparency and competition also manifests in reliance on expedited processes for many of these projects. It is not uncommon for transmission owners in MISO to rely on the "Expedited Project Review" process. These expedited projects can go from notice to MISO approval in as little as 30 days,[31] even though the in-service date for the expedited project is over a year away.[32] The speed at which these projects are processed makes it impossible for stakeholders to propose viable alternatives, even if those alternatives could meet the in-service deadline at lower cost. As of filing these comments, there are at least 18 current expedited review project requests in MISO.[33]

Importantly, these supplemental and other projects are not subject to competition. Transmission owners have realized that these "other" and "supplemental" projects are a way to maximize their own profits. By relying primarily on these projects, transmission owners can

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[29] *See* Consumer Advocates of the PJM States, Letter to PJM Board of Managers.

[30] MISO Planning Advisory Committee, Status Reporting for Approved MTEP Projects (PAC-2021-2), 8 (April 28, 2021), *available at* https://cdn.misoenergy.org/20210428%20PAC%20Item%2003a%20Status%20Reporting%20for%20Approved%20Projects%20(PAC-2021-2)544290.pdf

[31] MISO Business Practice Manual 20, 4.1.4, 63, *available at* https://cdn.misoenergy.org//BPM%20020%20-%20Transmission%20Planning113822.zip

[32] MISO Current Expedited Project Review Requests, *available at* https://cdn.misoenergy.org//Current%20Expedited%20Review%20Process%20Requests319756.zip

[33] *Id.*

avoid competition from ATTs and can forestall regional projects by making transmission planning and construction into a piecemeal process.

Beyond the lack of transparency, competition, and necessary time to properly propose and consider alternatives, transmission owners can obfuscate the benefits of ATTs (including GETs and demand-side resources) through a piecemeal planning approach. By proposing many small projects over a short period of time, transmission owners can flood transmission planners with individual projects that each seem reasonable and necessary. However, when viewed together the whole of the projects may be less than the sum of its parts. This is especially harmful when ATTs, non-transmission alternatives, or regional transmission projects could resolve the transmission package as a whole at lower cost but not when viewed piecemeal as presented by the transmission owner.

Without sufficient transparency and the ability to propose alternatives for these non-competitive transmission projects, transmission planners are unable to ensure that transmission rates are just and reasonable. ATT developers are effectively prevented from proposing alternatives that may be cheaper, faster, and lower impact than the projects transmission owners are increasingly relying on to avoid competition.

3. Failure to seek input from the distribution side of the grid ignores potential low-cost solutions to transmission needs.

The Congress in EPAct 2005 explicitly names distributed resources as an advanced transmission technology in need of deployment to meet transmission infrastructure needs.[34] Transmission Planners, however, often do not consider distributed resources when evaluating alternatives to proposed transmission projects despite continued growth of distributed solar and

[34] Order 890 at PP 436-437.

other distributed resources. This includes the incumbent transmission owners in RTOs/ISOs, who are often the driving forces behind non-regional, non-competitive transmission projects.

Distributed resources can significantly affect the needs for transmission systems. In MISO, for example, Vote Solar found that proper accounting of the distributed solar dispatch on Xcel Energy's distribution system significantly affects transmission needs.[35] Because the Commission does not currently require transmission planners to work with distribution utilities or distribution planners, it is likely transmission planners are selecting the wrong projects in some cases, especially where distributed energy resources are growing rapidly. This problem will only get worse as the costs of DERs come down and FERC Order No. 2222 brings greater numbers of DERs onto the transmission system.

4. Lack of development of advanced transmission technologies results in less renewable energy.

ATTs can significantly reduce congestion on transmission systems, allowing more renewables to get on the grid faster. Several studies have demonstrated that ATTs, including GETs, are effective at improving interconnection of renewable resources to the grid and delivery of those resources to load. A 2021 study by Brattle showed that a combination of just three kinds of ATTs (advanced power flow control, dynamic line ratings, and topology optimization) could

[35] Rao Konidena, Rakon Energy, *A report focusing on High Distribution Solar in Xcel Energy Supplemental IRP*, 32 (2021), *attached as* Attachment A.

double the amount of renewable generation integrated into the Southwest Power Pool.[36] The model achieved this massive increase in renewables with a payback period of just six months.[37]

Yet the implementation of ATTs lags significantly. Transmission owner business models incentivize investments in capital intensive, especially those local projects not subject to competition.[38] Because ATTs are typically not capital intensive, transmission owners prefer to invest in more expensive infrastructure and pass those costs on to ratepayers while earning a rate of return.[39] This perverse incentive, when combined with the issues of available information, transparency, lack of competition, and insufficient time to review projects discussed above leads to an overbuild of traditional transmission infrastructure (especially piecemeal lower voltage projects) and an under-build/-investment in ATTs, including GETs, storage, and distributed energy resources.

5. Limiting cost allocation of advanced transmission technologies to incumbent transmission owners is unjust and reasonable and is unduly discriminatory.

There is a danger that under current RTO/ISO practices even when ATTs are properly evaluated and selected, they will be limited to incumbent transmission owners. This significantly

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[36] T. Bruce Tsuchida, Stephanie Ross, Adam Bigelow, Brattle, *Unlocking the Queue with Grid-Enhancing Technologies*, 11 (Feb. 1, 2021), *available at* https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

[37] *Id.*

[38] *See* Department of Energy, Advanced Transmission Technologies, 29-30 (Dec. 2020), *available at* https://www.energy.gov/sites/prod/files/2021/01/f82/AdvancedTransmissionTechnologiesReport508.pdf

[39] *See e.g.* Speaker materials of Frank Kreikebaum, Smart Wires, AD19-19-000 (November 5-6, 2019) (explaining that a form of GETs could facilitate 1.5 GW of increased transfer capacity "at a fraction of the cost and time compared to building new infrastructure").

shrinks the pool of available alternatives and arbitrarily sets the threshold for selecting the best solutions at whatever transmission owners decide is best for their bottom line.

This concern is not purely hypothetical. In 2020, FERC approved tariff changes that allowed for the inclusion of storage as transmission only assets (SATOA) to be a part MISO's transmission planning process.[40] That same order, however, allowed MISO to limit compensation of SATOA to registered transmission owners.[41] This had the consequence of leaving many potential SATOA developers fighting an uphill battle. Where transmission owners can pick and choose SATOA solutions that best fit their interests, other storage owners with viable SATOA projects do not have access to the same cost allocation benefits, instead being pushed off into the "non-transmission alternatives" category despite having projects that clearly provide transmission services.

Limiting the cost allocation of transmission projects arbitrarily to incumbent transmission owners rather than to entities providing transmission services is unduly discriminatory. It also shrinks the supply of low-cost, fast to implement transmission solution, leading to unjust and unreasonable rates.

B. The Commission should require transmission planners to systematically study and make public the utilization of the existing grid.

Lack of information on the current utilization of the grid stifles development of ATTs. This is inconsistent with EPAct 2005 and Order 890. The lack of information results in unjust and unreasonable rates by leading to inefficient use of existing infrastructure.

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[40] FERC, 172 FERC ¶ 61,132, ER20-588 (August 10, 2020).

[41] *Id.* at P 63

The Commission should require all transmission planners, including RTOs/ISOs, to create a systematic process for evaluating the utilization rate of existing transmission infrastructure. These evaluations should be publicly available and readily accessible by stakeholders best in a position to use the information to propose lower-cost, faster to install, and smaller footprint alternatives to proposed transmission projects.

C. The Commission should require reforms to transmission planning that minimize the use of piecemeal, just-in-time projects.

Transmission planners' current reliance on small, local transmission projects leads to a lack of full and fair consideration of ATTs. The Commission should require reforms to transmission planning that requires transmission planners to minimize the use of piecemeal, just-in-time projects.

The Commission should require transmission owners to submit local projects for evaluation with sufficient lead time to allow stakeholders to properly evaluate alternatives. The Commission should also require transmission owners to provide transmission planners with a list of local projects looking forward several years. This will allow transmission planners to identify individual projects that can be resolved together with combinations of consolidated projects, regional projects, and ATTs. Finally, the Commission should consider further reducing the right of first refusal by opening local projects such as PJM's supplemental and MISO's other projects to competition.

D. The Commission should require transmission planners to consult with distribution utilities and their regulators to identify places where distributed energy resources impact transmission needs.

In FERC Order 2222, the Commission required RTOs/ISOs to establish market rules that address coordination between the RTO/ISO, distribution utilities, and electric retail regulatory authorities.[42] The Commission should order a similar requirement for RTOs/ISOs and other transmission planners to amend their tariffs to address coordination between transmission planners, distribution utilities, and electric retail regulatory authorities. This coordination should be aimed at understanding how assets on the distribution side of the grid could be used to resolve transmission needs.

III. Advanced transmission technologies must be part of the generator interconnection process.

The Commission seeks comment on whether it should require transmission providers to consider GETs in interconnection studies.[43] Commentors support this requirement. The problems with generator interconnection queues are well-documented. As the cost of renewable energy continues to fall, projects are entering the interconnection process at record numbers. But once projects enter the queue, they face the substantial hurdle of actually interconnecting. At the end of 2020, there were at least 460 GW of solar[44] and 209 GW of wind[45] in interconnection queues across the country.

A significant reason for the backlog in interconnection queues is lack of sufficient access to the grid. Costs to interconnect projects have risen steeply in recent years. In MISO, for

[42] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247, P 278 (2020).

[43] ANOPR at P 158.

[44] Mark Bolinger *et al.*, *Utility-Scale Solar, 2021 Edition*, 55 (Oct 2021), *available at* https://eta-publications.lbl.gov/sites/default/files/utility_scale_solar_2021_edition_slides.pdf

[45] U.S. Department of Energy, *Land-Based Wind Market Report: 2021 Edition*, vii (Aug 2021), *available at* https://www.energy.gov/sites/default/files/2021-08/Land-Based%20Wind%20Market%20Report%202021%20Edition_Full%20Report_FINAL.pdf

example, network upgrade costs required for interconnection have exceeded the apparent economic breakpoint since 2017.[46]

ATTs have the potential to lower the costs of interconnection and get more projects through the queue quickly. As several parties have presented to the Commission in its series of conferences on GETs, these technologies are often significantly cheaper and faster to implement than traditional wires-based transmission solutions.[47] Given that transmission upgrade costs and the time associated with those upgrades are limiting factors on getting through the interconnection process, the Commission should allow interconnecting customers the option of using ATTs over wires where appropriate.

The Commission should not simply allow transmission providers to independently decide on the viability of an ATT. As explained above, transmission providers have a financial incentive to select higher cost solutions. The Commission also acknowledged this in Order 845-A, finding that "interconnection customers have a greater economic incentive than transmission providers to

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[46] *See* ITC Holdings Corp., *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, 5 (May 20, 2020), *available at https://cdn.misoenergy.org/20200520%20AC%20Item%2004%20Current%20Issue%20-%20Generator%20Interconnection%20Queue447230.pdf*

[47] *See e.g.* Speaker materials of Frank Kreikebaum, Smart Wires, AD19-19-000 (November 5-6, 2019) (explaining that a form of GETs could facilitate 1.5 GW of increased transfer capacity "at a fraction of the cost and time compared to building new infrastructure"); Speaker materials of Rob Gramlich, WATT Coalition, AD19-19-000 (November 5-6, 2019) (explaining that limiting factor of deploying gets is that they are so low cost that utilities do not build them because "[t]he current system of rewards discourages lower capital cost activities."); Speaker materials of Joseph Bowring, Monitoring Analytics, AD19-19-000 (November 5-6, 2019) (explaining that where GETs are lower cost than traditional wires solutions, "Under cost of service regulation, the regulated transmission owner will always prefer a project with higher investment costs.").

reduce the cost of stand alone network upgrades."[48] The Commission should ensure that alternatives analyses for interconnecting customers are open and transparent. Customers should be able to vet transmission providers' ATT analyses to determine if they were sufficiently comprehensive.

The Commission should also take steps to allow interconnecting customers to leverage ATTs that speed up interconnection and reduce costs. In FERC Order 845-A, FERC found that expanding an interconnecting customer's option to build was necessary to prevent unjust and unreasonable rates because "interconnection customers have incentives to reduce network upgrade costs."[49] The Commission should clarify that ATTs can qualify as stand alone network upgrades pursuant to FERC Order 845-A. This would allow ATTs to be included in Order 845's option to build for the interconnecting customer.

IV. RTO/ISO governance reform is crucial to the successful integration of siting and advanced transmission technologies into the planning process.

The Commission seeks comment on the need for reforms to transmission planning oversight.[50] Commentors agree that reforms are necessary for well-functioning planning and interconnection processes. Transmission Planners must contend with a wide variety of input from a wide variety of stakeholders with a wide variety of interests. Without proper governance, transmission planners risk obstruction in the planning process. For example, Harvard's Ari Peskoe recently argued that investor-owned utilities sometimes have incentives to act in ways that lead to unjust and unreasonable rates:

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[48] *Reform of Generator Interconnection Procedures and Agreements, order on reh'g* Order No. 845-A, 66 FERC ¶ 61,137, P 33 (2019).

[49] *Id.* at P 31.

[50] ANOPR at P 159.

> Because IOUs [investor-owned utilities] are themselves interested parties and have incentives that diverge from their customers, competitors, and policymakers, they are not capable of acting as neutral arbiters in transmission planning processes. Like any profit-driven company, IOUs seek to sue their strategic advantages to advance their own interests. In a complicated transmission planning process, an IOU might use its informational advantages and position as the dominant local transmission owner and developer to block projects that harm its interests or to advance projects that benefit it financially but harm others.[51]

As the Commission continues to refine the transmission planning, cost allocation, and interconnection processes, these concerns about the ability for stakeholders to use the process to their own advantage remain.

The Commission should take actions to ensure that governance progresses along with the reforms that are the main subject of this ANOPR and Environmental Commentor's comments. Injection of siting into the planning process should not, for instance, be used by transmission owners to keep competing projects out of contention or to create undue delay in the planning phase. Similarly, requirements to evaluate advanced transmission solutions should not be means for incumbent utilities to keep non-incumbent developers out of the planning process.[52]

V. Conclusion

Commentors appreciate the opportunity to provide comments on the Commission's ambitious and important ANOPR. We believe this is a unique opportunity to radically transform the nation's transmission planning, cost allocation, and interconnection processes. We ask the Commission to include in this rulemaking process the siting and advanced transmission technologies issues presented in these comments.

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[51] Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, Energy Law Journal Vol. 42:1, 40 (2021).

[52] This is not merely hypothetical. As explained above, MISO's storage as transmission only asset has biased storage solutions in favor of incumbent utilities to the detriment of non-transmission owners who could offer comparable services.

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ATTACHMENT A

2021

A report focusing on High Distributed Solar in Xcel Energy Supplemental IRP

FOR VOTE SOLAR, INSTITUTE FOR LOCAL SELF-RELIANCE, AND COOPERATIVE ENERGY FUTURES

RAO KONIDENA

Rakon Energy LLC

Rakon Energy LLC report for Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures

focusing on High Distributed Solar in

Xcel Energy's Supplemental Integrated Resource Plan (IRP)

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I. Executive Summary

Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures retained Rakon Energy LLC to review Northern States Power (NSP) – Minnesota's (doing business as Xcel Energy) High Distributed Solar (HDS) modeling included in the company's June 30, 2020, Supplement to its 2020-2034 Upper Midwest Integrated Resource Plan in Docket Number E002/RP-19-368 (IRP). I reach several conclusions:

First, NSP must improve its planning to include additional distributed resources and treat them as a "central element to the utility's optimized plan." In fact, due to market changes, technology development, and federal policy including FERC Order 2222, it is inevitable that greater distributed resource development will occur and will need to be accommodated by NSP plans. Planning for greater distributed resource penetration at this stage would allow efficient resource optimization rather than inefficient after-the-fact adjustments to the Company's resource plans.

Second, distributed resources interconnected to Xcel's distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. Emphasizing distributed resources allows Xcel to integrate higher levels of renewable resources than by focusing on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.

Third, MISO is currently modeling more than 3,000 MW of DG PV in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that NSP should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.

Fourth, distributed solar, especially distribution connected DG within the Twin Cities Metro Area should have a higher Effective Load Carrying Capability than utility scale solar connected at transmission to remote nodes. Differences in the ELCC of resources has been shown to vary by interconnection node. Xcel and MISO should jointly determine the capacity value of distributed resources through a locational capacity value ELCC.

Lastly, this report points out that that distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value. The Commission should require Xcel to integrate distribution, transmission, and resources as part of its IRP to meet system's reliability needs most effectively, rather than through balkanized planning. High density distributed resources will produce higher locational capacity in and around the Twin Cities Metro Area and should be considered separately from other portions of NSP’s service territory.

II. High Distributed Solar (HDS) Modeling

A. NSP's Supplemental IRP modeled a "high distributed energy future" (High Distributed Solar or HDS) and expresses various concerns regarding high levels of distributed energy. NSP's HDS modeling contains certain flaws and NSP's concerns are overstated.

NSP should have assumed a higher level of baseline distributed resources and then modeled several additional levels of HDS to account for increments of distributed energy that NSP can achieve beyond the baseline level.

1. <u>NSP's Assumed Baseline Distributed Resource Level is not realistic when compared to MISO MTEP Futures</u>

NSP's Supplement IRP does model HDS as one of the "futures sensitivity" cases. However, because those model runs also assumed lower load forecasts, they ultimately produce lower capacity selection for HDS[1]. NSP did not accurately model incremental distributed resources as available capacity expansion options for selection when optimizing. According to the Supplemental IRP ("SIRP"), NSP "continues to use" its historic practice of adjusting load forecasts for energy efficiency, demand response and distributed generation "to estimate our net energy and load into the future" while also "test[ing] the economic impact of including various 'bundles' of EE and DR… to allow those resources to compete with traditional supply-side resources…" SIRP at p 19 of 78. Thus, the company assumes a baseline level of efficiency and demand response and then makes additional "bundles" available for the model to select. Distributed generation is

[1] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Page 38 of 78.

notably treated differently. The company does not make additional "bundles" or increments of distributed generation available for selection by the model. Instead, the company's modeling assumes a declining level of "Solar*Rewards" generation and a moderate to low level of "Community Solar" and "Distributed Solar" between 2020 and 2034. Those categories, combined, start at 366 MW in 2020 and end in 2034 at 340 MW. SIRP page 25 of 78, Table 2-2. That is, the company's baseline assumption is that total existing distributed generation resources actually decline during the planning period before a moderate amount of new distributed solar is forced into its expansion plans starting at 173 MW in 2020 and quickly declining to 16 MW in 2025 and then 15 MW annually 2026-2034. SIRP p 73, Table 3-1.

NSP's modeling did test the "sensitivity" of its plans to a higher level of distributed generation. However, it did not allow the model to select additional distributed generation as a resource as part of an optimized expansion plan. It also assumed that high distributed solar always occurs together with lower load growth. But Xcel did not test higher levels of distributed solar and higher levels of electrification and load growth together. SIRP at 35.

2. <u>Xcel's concern about solar dispatchability can be offset by MISO operator</u>

The Supplemental IRP expresses a fundamental desire by NSP to be able to meet peak demand without relying on intermittent resources or market purchases.[2]

[2] SIRP Page 41 of 78, Table 2-5: Scenario Modeling Portfolio Scorecard, "Reliability" ("Evaluates the share of peak load that we are able to serve without relying on NSP system use limited and variable resources, or off-system market energy and capacity purchases. This measure helps us identify market exposure in the event variable and use-limited resources are unavailable for a period of time.")

There are several problems with that criteria. First, contrary to NSP's description of it solar dispatchability as a "Reliability" concern, it is a financial concern. There is no reduction in reliability by relying on the market for energy or capacity. There is a potential cost, or financial risk, of doing so. But that is a financial consideration not a reliability consideration.

Second, the variability of resources does not mean that they should all be assumed unavailable at the time of system peak, which is what NSP's "Firm Dispatchable Resource to Peak Load Ratio" effectively does. Instead, NSP should utilize an analysis intended to account for variable resources. FERC approved MISO's treatment of solar as a Dispatchable Intermittent Resource (DIR)[3] and application of the Security Constrained Economic Dispatch (SCED) algorithm. As a DIR, HDS must submit a Day-Ahead forecast to MISO, but it is not financially binding due to solar forecasts' intermittent nature.

> "*For reliability purposes, each Intermittent Resource and Dispatchable Intermittent Resource must submit to the Transmission Provider a Day-Ahead forecast of its intended output for the next day consistent with the procedures for such forecast set forth in the Business Practices Manuals.* ***The Day-Ahead forecast shall not be financially binding on the Resource***.[4]"

As a qualified capacity resource in the MISO market, the MISO SCED and control room operator ultimately decide to dispatch a unit.

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[3] FERC approval of MISO's Solar DIR filing, https://cdn.misoenergy.org/2020-06-09%20171%20FERC%20%C2%B6%2061,203%20Docket%20No.%20ER20-595-000;%20-001452020.pdf

[4] Ibid, Requirement of Day-Ahead Forecast

Additionally, **dispatching distributed solar in MISO planning models is inevitable** because of 3,000 MWs plus DG PV capacity forecasted[5], which is an input into MISO transmission needs assessment. Hence it is recommended that NSP incorporate HDS in MISO capacity auction and leave the dispatch of HDS to MISO SCED and operator decision.

B. FERC Order 2222 requires Xcel and MISO to accept HDS as a market resource

NSP's failure to account for significantly more distributed generation in its baseline is inconsistent with the likely impacts of FERC Order 2222 on DER Aggregation (DERA). Order 2222 requires MISO to accept aggregated and individual DERs as wholesale market resources. As a distribution utility, Xcel must coordinate with both the HDS owner and MISO.

Xcel must figure out how to dispatch and coordinate with HDS to comply with FERC Order 2222. And Xcel's North American Electric Reliability Corporation (NERC) compliance obligations are tied to MISO's for the dispatch of distributed solar in the planning models. So, to comply with both upcoming FERC regulations on DERs and existing NERC planning regulations, Xcel must address HDS dispatch.

C. Distributed Generation Avoids Transmission Interconnection Limitations

The Supplemental IRP refers to currently backlogged transmission interconnection queues as a reason for limiting new renewable generation.

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[5] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

However, MISO allows Xcel to register distributed resources as capacity resources. Doing so avoids transmission interconnection issues.

1. MISO Deliverability Study ensures HDS is available for the entire MISO load

Distributed generation can count towards a Load Serving Entity's (LSE) resource adequacy requirements when deemed deliverable by MISO. Part of MISO's deliverability determination depends on whether there are transmission constraints that restrict a network resource's output. Alternatively, generation interconnected at the distribution level effectively provides capacity by reducing Xcel's peak load contribution to MISO's Planning Reserve Margin Requirement (PRMR), in turn reducing Xcel's capacity obligations at MISO.

Hypothetically, if Xcel has a 10,000 MW peak load and MISO's Unforced Capacity (UCAP) PRMR is 3.46 % - Xcel has a 10,346 MW capacity obligation. However, if 1,000 MW of distributed solar is interconnected to the Twin Cities Metro Area (TCMA) distribution system, Xcel's peak load is reduced to 9,000 MW. And Xcel only has a 9,311 MW capacity obligation assuming the same UCAP PRMR. That is, distributed resources have a greater than 1:1 capacity value and can avoid transmission interconnection delays and costs.

FERC Order 2222 allows HDS aggregation by Xcel as the distribution utility and coordinate with MISO as the transmission provider. The transmission facility where the HDS interconnects to the MISO system would be under MISO's functional control.

2. HDS capacity obligation reduction benefit

To quantify the capacity obligation reduction value in resource planning models, the difference in NSP obligation of 1,000 MW is worth at least $1.825 million per year in MISO capacity costs[6].

As part of the Planning Resource Auction (PRA) at MISO, which FERC approved, MISO LSEs have the option to point to resources approved in a state Integrated Resource Plan (IRP) to meet their PRMR. This option is called Fixed Resource Adequacy Plan FRAP[7].

Xcel is part of Local Resource Zone 1 at MISO. MISO's 2020/21 PRA includes 20,296 MW offered, and 14,198 MW of FRAP cleared in zone 1[8]. So, 70% of the offered FRAP capacity cleared in the 2020 MISO auction. Hence FRAP is common at MISO. And across MISO, 850 MW of solar cleared[9] in the 2020/21 PRA, increasing 25% relative to last year's auction.

3. HDS as a resource in FRAP must offer into MISO energy market

There is also a MISO market requirement for solar capacity resources cleared in the planning resource auction to participate in the Day-Ahead Market (DAM) called "must offer."

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[6] Slide 5 of MISO Planning Year 2020/21 auction shows $5 per MW-day which translates into $5,000 per day multiplied with 365 days in a year equals $1.825 million per year, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[7] MISO Resource Adequacy Business Practice Manual BPM-011-r23 Effective Date: March-31-2020, section 5.3 – Fixed Resource Adequacy Plan, page 89 of 183

[8] MISO 2020/21 PRA results, 04/14/2020: MISO Planning Resource Auction (PRA) for Planning Year 2020-2021 Results Posting, slide 7 of 17, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[9] Ibid, slide 11 of 17.

> *"an MP that owns a Capacity Resource that has ZRCs identified as part of a **Fixed Resource Adequacy Plan** or ZRCs which clear in an annual or Transitional PRA **must submit** the ICAP equivalent MW value of the cleared ZRCs into the **Day-Ahead Energy Market**, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unavailable due to a full or partial scheduled outage*[10]*"*

So, HDS can qualify as a capacity resource, and if cleared in the MISO PRA, has a must offer requirement in the MISO Day Ahead energy markets. The must offer requirement applies for all Dispatchable Intermittent Resources[11], which includes solar now due to FERC acceptance of MISO's DIR filing. **Hence HDS can participate in MISO capacity markets as a FRAP resource.**

D. Energy price (LMP) arbitrage opportunities with HDS

1. Xcel ignores the Locational Marginal Price (LMP) benefits of HDS.

Locational Marginal Price (LMP) is the sum of the marginal price of meeting the next MW of energy, transmission congestion, and transmission losses. This energy price is calculated at each Generation Elemental Pricing EPNode[12] on the

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[10] Section 4.2.3.6. Intermittent Resource Generation and Dispatchable Intermittent Resources – Must Offer, MISO BPM 011 – Resource Adequacy, Revision 15, Effective date of March 31, 2020. https://www.misoenergy.org/legal/business-practice-manuals/

[11] Ibid, “The must offer requirement applies to the Installed Capacity of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the UCAP rating.”

[12] Section 4.1, Elemental Pricing Nodes (EPNodes), MISO Network and Commercial Models Business Practices Manual (BPM), BPM 010 Revision 12

electric system inside the MISO market. If solar is located at an EPNode, this LMP is the price paid to the solar by the MISO market for serving the market load.

Xcel's supplemental IRP discusses MISO LMP in 2 areas: 1) its discussion of reliability, as a hedge against LMP price spikes when referring to firm dispatchable resource-to-peak load ratios in 2034[13], and 2) in its discussion of market sensitivities, to justify an adder for carbon[14]. **But Xcel's supplemental IRP does not consider the LMP benefits of HDS.**

Historical LMPs show where it would be worth locating market resources, either the supply side or demand side. If we look at the congestion component alone, market nodes with higher LMPs indicate a need for new transmission or alternatives to transmission solutions. And if we look at the transmission loss component alone, market nodes with higher prices indicate where HDS would benefit from reducing the transmission loss component.

Energy price arbitrage refers to buying energy at off-peak prices and selling energy at peak prices. If MISO dispatches Xcel HDS generation, Xcel Generation Elemental Pricing Node ("EPNode") receives the market-clearing price at that hour. During peak hours, this market price can be higher (generally in the order of hundreds of dollars per MWh) relative to off-peak hour prices (generally in tens of dollars per MWh). At a MISO market EPNode with HDS, Xcel can charge a battery

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[13] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Page 50 of 78, right before the Figure 2-20: Firm Dispatchable Resource-to-Peak Load Ratios in 2034, "we are hedged during periods of extreme MISO market demand and/or locational marginal price (LMP) spikes."

[14] Attachment A: Supplement Details, Page 135 of 176, "In the base modeling, an adder for the regulatory cost of carbon is placed on the locational marginal price (LMP) in the market for both purchases and sales using the forecasted annual average MISO emissions rate".

with solar energy obtained at off-peak pricing[15] and discharge the battery energy at peak. Xcel's ratepayers stand to benefit from energy price arbitrage because shifting stored solar energy (without fuel costs) from off-peak to peak hours results in less need to turn on fossil fuel units with fuel costs for the evening ramp.

LMP arbitrage opportunities occur at the Generation Elemental Pricing Nodes (as mentioned earlier), which are aggregated at Generation Commercial Pricing nodes (CPNode) or "Gennode" for short, on the MISO system. Xcel's supplemental IRP includes analysis of MISO market sales at the Generator pricing nodes as indicated in the Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures, Information Request No. 5[16] ("19-0368 VS ILSR CEF-005"). So, Xcel should investigate the LMP benefits of HDS.

It is worth noting that when discussing the nuclear update in section VIII, Xcel mentions the MISO Day Ahead Market to make a finer point[17] about ramping down nuclear units to accommodate more renewables on the grid. Hence, Xcel considers MISO market opportunities for certain resources in this resource plan. It

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[15] From Xcel Integrated Distribution Plan – Annual Update, Attachment A – Page 4 of 26, "Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe."
[16] Data Request Response 19-0368 VS ILSR CEF-005, "the market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond. In the Encompass modeling, market sales were limited to 25 percent of retail load in the capacity expansion runs in order to limit sales risk exposure"
[17] Attachment A: Supplement Details, Page 121 of 176, "in order to accommodate more variable renewables on the grid, we have worked to develop operational strategies that allow us to offer the plants into the MISO Day-Ahead market on an economic basis, allowing for MISO to schedule a portion of the plants to be more responsive to market signals and ramp output accordingly".

is therefore reasonable for Xcel's plan to consider similar MISO market opportunities for HDS.

2. Leveraging battery storage for energy price arbitrage in MISO is a proven concept, and MISO has experience with market participation by storage resources as well as storage dispatch.

FERC Order 841 mandates that each ISO shall have a market participation model for electric storage resources. Batteries can participate in the MISO market by registering as a Stored Energy Resource (SER) Type II[18]. In fact, Xcel has experience with a battery resource participating in the MISO market as Stored Energy Resource (SER). Xcel's 5MWh battery project at Luverne, Minnesota is an SER in the MISO market participation model. As an SER, Xcel's battery can provide regulating reserves in MISO's ancillary services market. And with an SER Type II category[19], Xcel's battery can provide capacity, energy, and other ancillary services such as spinning, supplemental and ramping services.

In addition to the existing Luverne battery, Xcel has 270 MW[20] of battery storage in the "active" study status of the MISO generator interconnection queue as of December 2020. For a 100 MW request (J1468) storage project waiting to be

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[18] FERC Docket # ER19-465, November 1, 2019, ""MISO notes that the requested deferred implementation of the ESR participation model is expected to have limited impacts on the ability of storage-type resources to participate in MISO's markets. While MISO recognizes there are storage-type Resources in MISO's current Generation Interconnection queue, it maintains that any storage-type Resources that emerge from the interconnection queue and actually enter into service before June 2022 can participate in MISO's markets as Stored Energy Resources – Type II ("SER-Type II")."

[19] FERC Docket # ER19-465, MISO filed on December 3, 2018 – MISO Compliance Plan for FERC Order 841, https://elibrary.ferc.gov/eLibrary/search

[20] MISO Queue, https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/# , project numbers are J1045, J1468, J1494, J1495, and J1498.

interconnected at the Xcel transmission substation, the earliest date for Generator Interconnection Application (GIA) execution is August 2022. That timeframe misses the deadline for the MISO planning resource auction in April 2022. Therefore, instead of depending on the MISO queue (which is lengthy and outside Xcel's control), Xcel has a much better chance of interconnecting HDS with storage to participate in MISO markets leveraging its Luverne battery experience.

Moreover, MISO has experience with market participation by storage technologies, as well as storage dispatch. The Ludington pumped storage units located in Michigan and jointly owned by Consumers Energy and DTE Energy, for example, participate in MISO markets for energy price arbitrage. During night time, i.e., the off-peak time, the Ludington units charge by pumping water up the reservoir. During day time, i.e., the peak time, the Ludington units discharge the stored water to run the electric generator[21].

3. <u>Xcel must examine the locational aspects of HDS, including transmission and distribution system benefits, in this IRP</u>

Xcel did not examine transmission or distribution system benefits to evaluate the energy market feasibility of an HDS future. [22] In response to a data request on this subject, Xcel stated that:

"our Integrated Resource Planning process is primarily focused on size, type, and timing of potential future resource additions. As such, ***we do not***

[21] MISO Market SubCommittee August 21, 2018 Pumped Storage presentation, https://cdn.misoenergy.org/20180821%20Order%20841%20Workshop%20Item%2002%20Pumped%20Storage268634.pdf

[22] Data Request Response 19-0368 VS ILSR CEF-003

> ***examine locational aspects of specific distributed resource additions*** *in the IRP"*

But Xcel's supplemental IRP takes into accounts the locational value of wind:

> *"We note that we have shifted from using the MISO footprint average wind ELCC of 15.6 percent to the most recent Zone 1 specific ELCC of 16.7 percent, in order to better capture the higher locational value of wind resources in our specific region[23]"*

Hence it reasonable to expect Xcel to model HDS accurately to assess locational impacts of HDS, including transmission and distribution system benefits.

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To summarize, HDS (particularly HDS located inside the TCMA) provides a hedge against LMP price spikes. Xcel should leverage its experience with Luverne battery storage participation in the MISO market and reflect the energy price arbitrage opportunities associated with HDS in its IRP.

E. Inside Twin Cities Metro Area

This report recommends that Xcel quantify the capacity value of locating distributed solar inside the 4 county "Twin Cities Metro Area" within Xcel's service area because HDS will be located closer to NSP's substations where peak demand occurs.

[23] Supplemental IRP footnote 14, page 22 of 78

For this report, the Twin Cities Metro Area (TCMA) is defined as Xcel's service area in the Minnesota Electric Transmission Planning Twin Cities Zone[24] (which Xcel referenced in data request 19-0368 VS ILSR CEF-004). According to the Minnesota Electric Transmission Planning website, eight Minnesota counties – Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott, and Washington- are in the Twin Cities Zone. Xcel's substations in Dakota, Hennepin, Ramsey, and Washington are inside the TCMA as shown in Figure 1, and Xcel's substations in Anoka, Carver, Chisago, and Scott counties are outside the TCMA.

According to the Minnesota State Demographic Center data[25], in 2019, Minnesota's population was greater than 6 million. More than 3.2 million people

[24] Minnesota Transmission Planning zones are shown here: http://www.minnelectrans.com/minnesota-zones.html

[25] Downloaded data titled, Latest annual estimates of Minnesota and its 87 counties' population and households, 2019. (Excel file, released August 2020.) from Our Estimates / MN State Demographic Center

live in the eight-county Twin Cities Zone, and of that population, 2.5 million reside in the TCMA as defined in this report.

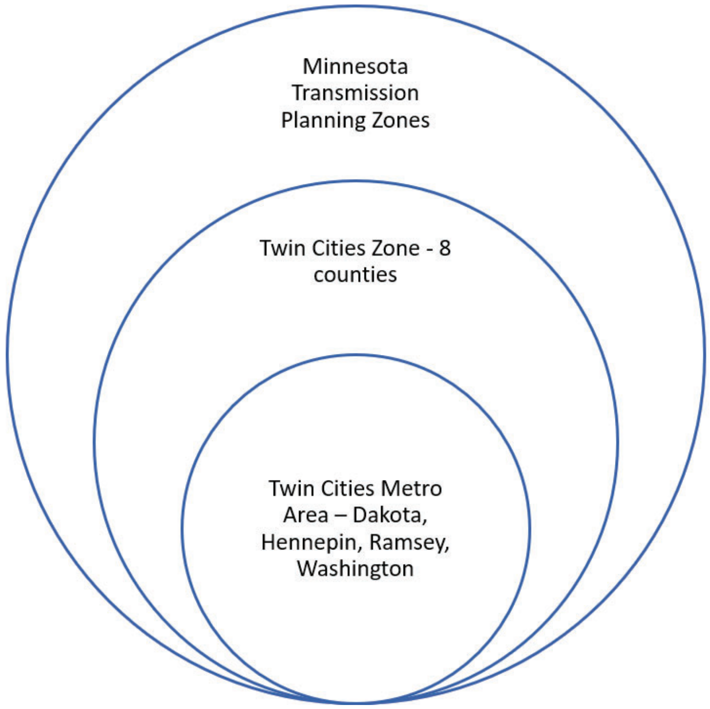

Figure 1: TCMA Definition Illustration

Xcel serves customers in the TCMA and outside the TCMA but within the Twin Cities Zone. In this section of this report, we focus on the TCMA because the TCMA includes several major Xcel substations (such as Merriam Park, Saint Louis Park, Edina, East Bloomington, Woodbury, Eden Prairie, and West Coon Rapids) and because from a transmission planning perspective, Xcel is planning at the Twin Cities zonal level.

1. <u>A portion of the 995 MW of HDS potential in Xcel's service area can be interconnected to Xcel's distribution system ahead of MISO's April 2022 planning auction.</u>

The capacity contribution of HDS cannot be overstated for Xcel because the MISO capacity auction includes provisions for Xcel's IRP capacity. More than 70% of IRP capacity cleared in MISO's latest auction[26]. HDS can be a part of the MISO auction's capacity as early as December 2021, in preparation for the April 2022 MISO auction.

Compared to the 1937 MW of solar shown in Table 1 waiting to be studied[27] by MISO in their generator interconnection queue (at Xcel's transmission substations), interconnecting 995 MW[28] of HDS potential at Xcel's distribution substations is entirely within Xcel's control[29].

Most of Xcel's 1937 MW in the MISO queue may see a study report in the next 2 years, around July 2022, with a potential agreement execution in March 2023[30]. That 3-year delay will miss the window for MISO's planning year 2022/23 and possibly 2023/24. In contrast, some of the 995 MW of HDS potential can be distribution interconnected as soon as December 2021 in time for MISO's planning auction in April 2022.

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[26] Slide 7, 2020/21 PRA Results by Zone shows 14,000 MW of FRAP cleared in Zone 1 out of the 20,000 MW offered. https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[27] MISO Generator Queue, filtered for solar fuel type, "Active" study status and Northern States Power (Xcel Energy) Transmission Owner in Minnesota.

[28] From Xcel's 2020 hosting capacity analysis (DISTRIBUTION SYSTEM – HOSTING CAPACITY ANALYSIS REPORT, Docket No. E002/M-19-685).

[29] Search for docket #, RM18-9, and filed date of October 07, 2019 in this FERC eLibrary, https://elibrary.ferc.gov/idmws/search/fercgensearch.asp "DERs typically connect to distribution facilities and are subject to the rules of the directly connected local distribution provider ("Host Distribution Provider") rather than the MISO Tariff. MISO's historic involvement with distribution-level interconnections largely has been limited to coordinating with the Host Distribution Provider where MISO is identified as an affected system."

[30] MISO Queue timeline - https://cdn.misoenergy.org//Definitive%20Planning%20Phase%20Schedule106547.pdf

Table 1: Total amount of solar waiting to be interconnected at Xcel's substations (Source: MISO queue, Jan 2021)

	Request S	Queue Date	Appl In Servi	County	Study Cycle	Study Gro	Study Phase	Service Ty	Summer M
J1001	Active	3/12/2018	9/1/2020	Lincoln County	DPP-2018-APR	West	PHASE 2	NRIS	40
J1072	Active	3/12/2018	9/1/2020	Mower County	DPP-2018-APR	West	PHASE 2	NRIS	150
J1098	Active	3/12/2018	9/30/2022	Jackson County	DPP-2018-APR	West	PHASE 2	NRIS	40
J1105	Active	3/12/2018	9/1/2020	Dakota County	DPP-2018-APR	West	PHASE 2	NRIS	200
J1212	Active	4/27/2019	10/31/2023	Murray County	DPP-2019-Cycle	West	PHASE 1	NRIS	60
J1337	Active	4/29/2019	6/30/2022	Sherburne County	DPP-2019-Cycle	West	PHASE 1	NRIS	300
J1445	Active	4/29/2019	8/1/2022	Benton County	DPP-2019-Cycle	West	PHASE 1	NRIS	100
J1446	Active	4/29/2019	8/1/2022	Wright County	DPP-2019-Cycle	West	PHASE 1	NRIS	150
J1461	Active	4/29/2019	8/1/2022	Carver County	DPP-2019-Cycle	West	PHASE 1	NRIS	50
J1473	Active	4/29/2019	8/1/2022	Chisago County	DPP-2019-Cycle	West	PHASE 1	NRIS	100
J1581	Active	7/10/2020	9/1/2023	Nobles	DPP-2020-Cycle	West	Study Not Started	NRIS	200
J1605	Active	7/10/2020	9/1/2023	Sherburne	DPP-2020-Cycle	West	Study Not Started	NRIS	200
J1620	Active	7/13/2020	9/1/2023	Pipestone	DPP-2020-Cycle	West	Study Not Started	NRIS	125
J803	Active	6/16/2017	10/1/2019	Lyon County	DPP-2017-AUG	West	PHASE 2	ERIS	32.5
J874	Active	6/16/2017	9/30/2021	Murray County	DPP-2017-AUG	West	PHASE 2	NRIS	150
J905	Active	6/16/2017	9/15/2020	Pipestone County	DPP-2017-AUG	West	PHASE 2	NRIS	40
									1937

As discussed in the earlier section of this report, for resources inside the TCMA, once qualified by MISO as a capacity resource, Xcel can meet its capacity obligations as a Load Serving Entity (LSE) addressing the Planning Reserve Margin Requirement (PRMR) of MISO.

In summary, given Xcel's stated concerns regarding capacity needs, it may realize a capacity benefit from siting HDS inside the TCMA and participating in MISO's planning auction via FRAP indicated in the MISO's latest auction, which cleared 850 MW of solar.

2. Reliability benefits of HDS in the TCMA

In addition to the capacity benefits that HDS provides, HDS resources around the TCMA can provide reliability to meet the NERC resource assessment criteria (BAL-502-RF-03) of 1 day in 10 years. All else equal, smaller and multiple units provide better reliability when compared to single units with a larger capacity. For example, ten 1 MW units provide better reliability than a single 10 MW unit—a system with ten 1 MW units translates into 0.1 days per year, and hypothetically, a power system with a single 10 MW unit would have a higher than 0.1 Loss of Load Expectation (LOLE).

One way to look at the reliability benefits of HDS is through Xcel's hosting capacity analysis. Does any given substation have enough capacity for the interconnection of the distributed solar? For each substation inside the TCMA, the answer to that question appears to be yes (see **Error! Reference source not found.** below).

As Table 2 demonstrates, there is a potential 995 MW of hosting capacity available for HDS within the TCMA. If 995 MW of HDS were interconnected to Xcel's distribution system inside the TCMA, it would provide reliability benefits to the grid.

Table 2: Hosting Capacity available inside the TCMA

Substation	HCA	County	Substation	HCA	County	Substation	HCA	County
Merriam Park	41.13	Ramsey	West Coon Rapids	15.37	Hennepin	Air Lake	7.58	Dakota
Wilson	38.16	Hennepin	Rose Place	15.33	Ramsey	Glen Lake	7.31	Hennepin
Saint Louis Park	37.13	Hennepin	Battle Creek	14.34	Ramsey	Afton	7.22	Washington
Twin Lake	36.25	Hennepin	Lone Oak	14.05	Dakota	Hugo	7	Washington
Southtown	30.34	Hennepin	Rogers Lake	14	Dakota	Fifth Street	6.84	Hennepin
Edina	28.88	Hennepin	Elliott Park	13.88	Hennepin	Brooklyn Park	6.71	Hennepin
Medicine Lake	27.67	Hennepin	Main Street	13.52	Hennepin	Mound	6.71	Hennepin
Westgate	27.23	Ramsey	Elm Creek	12.84	Hennepin	Shepard	5.89	Ramsey
Upper Levee	25.88	Ramsey	Riverside	12.84	Hennepin	Hastings	5.55	Dakota
Parkers Lake	24.38	Hennepin	Gopher	12.33	Hennepin	Viking	5.46	Hennepin
Aldrich	24.28	Hennepin	Bassett Creek	12.24	Hennepin	Cedarvale	5.02	Dakota
Lexington	24.22	Ramsey	Summit Ave	12.21	Ramsey	Chemolite	5.02	Washington
Terminal	21.9	Hennepin	Ramsey	12.14	Ramsey	Long Lake	4.6	Washington
Dayton's Bluff	21.08	Ramsey	West River Road	12.12	Hennepin	Arden Hills	4.23	Ramsey
East Bloomington	19.49	Hennepin	Hiawatha West	11.61	Hennepin	Prior	3.96	Ramsey
Woodbury	19.32	Washington	Cottage Grove	11.55	Washington	Hollydale	3.44	Hennepin
Osseo	18.96	Hennepin	Stockyards	11.48	Ramsey	Baytown	3.18	Washington
Gleason Lake	18.9	Hennepin	Midtown	11.15	Hennepin	West Hastings	2.68	Dakota
Western	18.61	Ramsey	Hassan	10.87	Hennepin	Williams Brothers Propane	2.5	Dakota
Tanner's Lake	18.29	Ramsey	Airport	10.82	Hennepin	Vermillion	1.75	Dakota
Eden Prarie	16.96	Hennepin	Nine Mile Creek	10.32	Hennepin	Kegan Lake	1.22	Dakota
Red Rock	16.87	Dakota	Kohlman Lake	10.13	Ramsey	Pine Bend	0.91	Dakota
Oakdale	15.97	Washington	Indiana	9.85	Hennepin	Farmington	0.61	Dakota
Hyland Lake	15.41	Hennepin	Cedar Lake	9.34	Hennepin		**105.39**	
	587.31		Deephaven	8.89	Hennepin	Total	**995.92**	
				303.22				

Additionally, Xcel may realize potential reliability benefits from HDS at substations inside the TCMA, depending on the times at which the substations in the TCMA peak compared to the Xcel system peak. When substations inside the TCMA peak at different times, the distribution system would be less stressed because of the diversity in peak hour across the TCMA compared to the Xcel system peak.

Treating TCMA without HDS is similar to modeling a lumpsum single 10 MW unit. But with multiple substations modeled within TCMA as 10 – 1 MW units, better reliability is seen by a reduction in Expected Unserved Energy[31] (EUE) during the peak demand hours. Hence there is a reliability benefit of locating HDS across the TCMA. Unfortunately, we have not been able to determine the peak times for TCMA substations. In response to discovery requests on this subject, Xcel did not provide the necessary information citing grid security concerns.

F. Outside the Twin Cities Metro Area

1. Capacity benefits of locating HDS outside the Twin Cities Metro Area (TCMA)

Locating HDS outside the TCMA can also provide a capacity benefit when those resources participate in MISO's planning auction via FRAP. Xcel is part of Local Resource Zone (LRZ) 1 in the MISO auction, and any transmission limitations with other zones are reflected in the Capacity Import Limits (CIL) and Capacity Export Limits (CEL) calculations[32] in the MISO auction. This MISO modeling ensures transmission limitations between the zones are considered when determining the

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[31] Attachment A Supplement Details, "Expected Unserved Energy (MWh) is total amount of energy that could not be served." Page 164 of 176

[32] MISO 2020/21 PRA results, 04/14/2020: MISO Planning Resource Auction (PRA) for Planning Year 2020-2021 Results Posting, slide 3 of 17, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

LSE requirements to meet PRMR. Xcel can address capacity needs by having HDS resources participate in the MISO auction,whether those resources are located inside or outside the TCMA.

2. Reliability benefits of HDS outside the TCMA

HDS resources outside the TCMA also provide reliability benefits to Xcel. There is approximately 300 MW of hosting capacity available at substations outside the TCMA, as shown in Table 3. This 300 MW could supplement Xcel's MISO capacity obligations because this 300 MW is also part of MISO LRZ1.

Table 3: Hosting Capacity available outside the TCMA

Substation	HCA	Substation	HCA	Substation	HCA	Substation	HCA	Substation	HCA	
Moore Lake	25.5	Fair Park	4.07	Birch	1.3	Tracy	0.46	Westport	0.06	
Goose Lake	15.96	Credit River	3.87	South Ridge	1.29	Frontenac	0.45	Essig	0.04	
Eastwood	15.77	Rich Valley	3.87	Albany	1.26	Wobegon Trail	0.45	Sedan	0.04	
Winona	10.29	West Faribault	3.68	Dahlgren	1.22	Blue Herron	0.42	West Union	0.03	
Coon Creek	9.72	Dodge Center	3.6	Saint Joseph	1.21	Stewart	0.42	Rosemount	0.01	
Oak Park	9.72	Sauk River	3.48	Cannon Falls	1.12	Gibbon	0.41			
Waseca	9.65	Kasson	3.37	Yellow Medicine	1.12	Lake Yankton	0.37			
Goodview	9.23	Pipestone	3	Pine Island	1.09	Bird Island	0.3			
Savage	8.78	Orono	2.96	Maple Lake	1.08	Henderson	0.3			
Bluff Creek	8.54	Excelsior	2.52	Cannon Falls Transmission	0.94	Mazeppa	0.3			
Sibley Park	8.08	Waconia	2.49	Rich Spring	0.93	Rapidan	0.29			
Crossroads	7.63	Burnside	2.42	Watertown	0.92	Green Isle	0.21			
Crooked Lake	7.05	La Crescant	2.36	Gaylord	0.9	Kenyon	0.21			
Granite City	7.02	Plato	2.08	Swan Lake	0.89	Lafayette	0.19			
Red Wing	6.23	Montevideo	2.07	Slayton West	0.76	Villard	0.18			
Blue Lake	6.17	Linn Street	2.01	Dassel	0.6	Hadley	0.17			
Riverwood	6.08	Wakefield	1.97	Eagle Lake	0.54	Cokato	0.16			
Salida Crossing	6.03	Wabasha	1.92	Greenfield	0.54	Sacred Heart	0.16			
Northfield	4.95	East Winona	1.88	Vesili	0.54	Butterfield	0.15			
Faribault	4.72	Jordan	1.87	Renville	0.5	Becker	0.11			
Lake Bavaria	4.42	Crystal Foods	1.76	Kimball	0.48	Belle Plain	0.1			
Saint Cloud	4.4	Fiesta City	1.74	Paynesville Transmission	0.48	Brownton	0.1			
Wyoming	4.39	Atwater	1.42	Danube	0.47	Castle Rock	0.1			
Dundas	4.31	First Lake	1.36	Franklin	0.47	South Haven	0.1			
	205	Howard Lake	1.32	Saint John's	0.47	Meeker	0.09			TOTAL
			63		**21**		**6**		**0.18**	**295**

G. HDS interconnecting to a Wholesale Distribution Service (WDS Facility)

This report has discussed the benefits of Xcel registering HDS as a MISO market resource**.** Alternatively, according to MISO, a DER provider, i.e., HDS operator, could contact MISO directly to determine whether a facility the HDS operator seeks to interconnect is within the PUC jurisdiction or MISO functional control:

> *"there are **two methods that DER** could use to ascertain the process applicable to its interconnection request. First, the DER could contact the Host Distribution Provider to determine whether the MISO process or the Host Distribution Provider's process applies to a given facility. Second, the DER could obtain this information directly from MISO[33]."*

Xcel owned transmission facilities transferred to MISO are called Transferred Transmission Facilities ("TTF"). Similarly, if distribution connected HDS is connected to the MISO transmission system and under MISO functional control, it is called Wholesale Distribution Service (WDS Facility).

Since MISO does not have any WDS facilities to-date (per their data request response to FERC), this approach could be discussed actively at MISO's FERC order 2222 related stakeholder DER Task Force because FERC Order 2222 mandates MISO to provide opportunities for DERs to participate in MISO energy, capacity, and ancillary services markets. Any HDS above 100 kW qualifies as a DER per FERC definition in this Order 2222.

Hence WDS Facilities are distribution system elements like TCMA substations discussed earlier where a Distributed Energy Resource (DER) provider like customer-owned HDS interconnects to a distribution facility to access MISO

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[33] In MISO response to the Federal Energy Regulatory Commission (FERC) data request on Distributed Energy Resource Aggregation (DERA) docket # RM18-9.

market benefits. As a result, this WDS facility becomes part of the MISO functional control list of Transferred Transmission Facilities (TTF).

1. <u>Why is WDS Facility important for HDS interconnection?</u>

MISO Generator interconnection queue request is one way to access the MISO transmission system. As this report has previously recommended, given that Xcel has no control over the MISO queue process, and the MISO queue is backed up by more than a few years, Xcel can work right away with HDS owners by studying the interconnections to Xcel's distribution system without waiting for MISO's study results. Xcel can submit Transmission Service Requests for the distribution connected HDS for MISO to grant transmission access. Xcel can reduce its capacity obligation by pointing to Aggregated HDS (which has transmission access) in its Fixed Resource Adequacy Plan (FRAP) at MISO's capacity auction.

To obtain MISO transmission service, MISO has explained that[34] a WDS Facility can take one of two alternate paths: 1) Apply for an External – Network Resource Interconnection Service (E-NRIS), or 2) Apply for a specific Point-To-Point or Network transmission service[35]. Because both inside and outside TCMA

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[34] In MISO response to the Federal Energy Regulatory Commission (FERC) data request on Distributed Energy Resource Aggregation (DERA) docket # RM18-9.

[35] Search for docket #, RM18-9, and filed date of October 07, 2019 in this FERC eLibrary, https://elibrary.ferc.gov/idmws/search/fercgensearch.asp "MISO provides two services that a DER must choose between for MISO to study the DER's deliverability: (1) External Network Resource Interconnection Service ("E- NRIS"); or (2) firm Transmission Service (either Point-To-Point or Network) from the DER unit to a particular load. If the DER elects to obtain E-NRIS, they must submit an Interconnection Request specifying that the DER is seeking E-NRIS and be studied through MISO's 3-phase DPP (described above). If the DER elects to obtain firm Transmission Service to be deliverable to specific load, then the Interconnection Customer must submit a Transmission Service Reservation ("TSR") and adhere to MISO's TSR study procedures"

substations are within MISO LRZ1, Xcel can apply for HDS to seek a specific Point-To-Point transmission service.

As the "host distribution provider," Xcel would aggregate the HDS resources and participate in the MISO market. **Hence there already exists a path for HDS to participate as a DER at MISO**.

While we do not know if Xcel has already discussed the option of using WDS facilities to register HDS as DER at MISO, it is clear that Xcel has an opportunity to do as it works with MISO at the DER Task Force for FERC Order 2222 implementation.

To summarize, if Xcel thoroughly vets the HDS interconnection at a WDS facility, there is a potential for more of Xcel's facilities to be transferred to MISO functional control. The specific facilities to be transferred to MISO would depend on Xcel's hosting capacity analysis since Xcel is the distribution utility. MISO, as the transmission provider, would coordinate with Xcel.

III. Effective Load Carrying Capability (ELCC) calculation of HDS

Effective Load Carrying Capability (ELCC) is the standard metric to determine a variable resource's contribution to serving demand. Xcel does not sufficiently analyze the ELCC for distributed solar relative to utility-scale solar in its supplemental IRP. Xcel states:

> *"Our base assumptions include a solar ELCC values that declines from 50 percent to 30 percent between 2023-2033. This alternate sensitivity examined the effect of maintaining a 50 percent ELCC throughout the modeling period. As*

> *expected, a **higher capacity accreditation value results in the models selecting more solar at an overall lower portfolio cost**. That said, we believe a declining ELCC assumption is consistent with MISO and other utilities' long-term planning approaches and more appropriately reflects the reality of solar resources' ability to meet capacity needs in markets with increasing solar adoption[36]."*

There is a direct relationship between capacity credit and ELCC. ELCC is calculated as a first step towards determining the capacity credit of the resource. Capacity credit is how much capacity of a variable resource counts towards meeting a Load Serving Entity's (LSE) capacity obligations.

A. Xcel should model HDS to reflect the locational value of distributed solar in ELCC

MISO has experience calculating ELCC for wind. Due to solar as a DIR – FERC filing approval, MISO expected to start calculating ELCC for solar for the 2021-2022 Planning Year. But since the transmission interconnected solar MW threshold was not reached, MISO continues to assign 50% solar capacity credit for the next 2021/22 planning year[37]. This 50% credit is good news for HDS and Xcel.

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[36] Attachment A: Supplement Details, X. Modeling Scenario Sensitivity Analysis – PVRR & PVSC Summary, Page 136 of 176.

[37] MISO Planning Year 2021-2022 Wind & Solar Capacity Credit December 2020 DRAFT found here, "Total registered solar in the MISO system (including behind-the-meter) is projected to reach 4,635MW ICAP in December 2021. MISO will continue to use the current accreditation methodology for new solar resources until sufficient operational data is available to perform a solar capacity credit study." https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf

For solar, Xcel models ELCC at 50%[38] for 2020-23 and 30% for the next 10 years, reflecting the conventional wisdom that increasing renewable penetration eventually leads to lower ELCC eventually (as illustrated by increasing wind penetration in MISO). Since ELCC is inversely proportional to the solar registered as a percentage of peak load in the MISO market, as solar market registrations increase, there is reason to believe ELCC % would decrease.

Historical MISO ELCC data for wind shows, even though the MISO system-wide average capacity credit for wind is approximately 15%, individual CPNodes have a higher credit based on their geographic location.

> "*While evaluation of all CPNodes captures the benefit of the geographic diversity, it is also important to assign the capacity credit of wind at the individual CPNode locations to recognize the capacity contributions of each individual wind-generating unit. In a market, it is important to convey where wind resources are approximately more effective, and how the location and corresponding relative performance of each wind CPNode relates to the contribution of wind ELCC to system-wide reliability*[39]."

Similarly, **we can expect solar capacity credit to reflect a higher locational value for HDS** inside the TCMA versus outside the TCMA because the geographic

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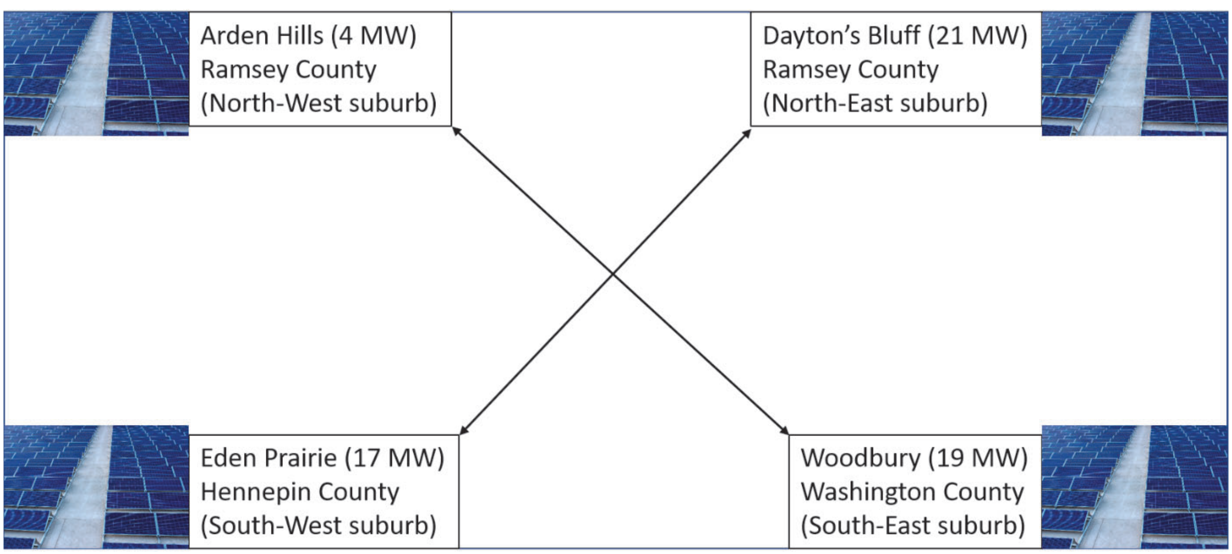
[38] Attachment A: Supplement Details, Page 88 of 176, "In the first several years of the analysis period, we use the current 50 percent ELCC, corresponding to a 250 MW accredited capacity for generic new solar. By 2033, however, the modeled ELCC declines to 30 percent, which would correspond to 150 MW of accredited solar capacity"

[39] Section 3, Details of Wind Capacity by CPNode, MISO report - Planning Year 2020-2021 Wind & Solar Capacity Credit December 2019.

diversity of HDS located at TCMA substations is reflected in a higher capacity credit at individual CPNode inside TCMA versus outside the TCMA.

ELCC for HDS is much better than for utility-scale Solar. If Xcel models HDS as outlined here in the TCMA, ELCC for some TCMA substations would reflect a higher locational value because it is unlikely that all substations in the TCMA would experience a peak load simultaneously.

For example, referring to the TCMA Hosting Capacity Table (Table 2: Hosting Capacity available inside the TCMA), Arden Hills in the TCMA is a North-West suburb, diagonally opposite Woodbury in the South-East suburb. Similarly, Eden Prairie is a South-West suburb, is diagonally opposite Dayton's Bluff in the North-East suburb, as shown in Figure 2. As a result, the contribution of HDS increases by spreading across the metro area, compared to a single utility-scale solar unit at one location.



Source for solar picture - Photo by Angie Warren on Unsplash

Figure 2: HDS at TCMA Substations provides locational value

This benefit of locating HDS at multiple substations across the TCMA, reducing the risk of placing solar at a single Generation EPNode[40] (unfortunately, Xcel has not shared the peak times, citing "grid security" concerns), is similar to the MISO footprint diversity benefit. **MISO estimates more than $2 billion[41] in footprint diversity** benefits for its members because hypothetically, the peak demand of MISO east members (located in Michigan) does not occur at the same time as the peak demand of MISO west members (located in Minnesota).

Therefore, it is reasonable, and this report recommends that Xcel apply MISO footprint diversity to HDS inside and outside the TCMA.

Xcel is aware of the locational value of resources, specifically wind[42].

> *"We note that we have shifted from using the MISO footprint average wind ELCC of 15.6 percent to the most recent Zone 1 specific ELCC of 16.7 percent, in order to better capture* ***the higher locational value*** *of wind resources in our specific region"*

Hence it reasonable to expect Xcel to model HDS and test the hypothesis of higher locational value for HDS in the TCMA, which may result in a higher ELCC.

A higher ELCC for HDS translates into a higher capacity credit.

To summarize, Xcel did not account for the potential locational benefits of HDS, and adjust the ELCC for distributed solar accordingly. In markets and regions

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40 Responses to 19-0368 VS ILSR CEF-020 onwards reference
41 MISO 2019 Value Proposition, slide 11 of 16, https://cdn.misoenergy.org/20200214%202019%20Value%20Proposition%20Presentation425712.pdf
42 Supplemental IRP footnote 14, page 22 of 78

where there is high penetration of distributed solar such as TCMA, there is a higher ELCC value for HDS that Xcel should have reflected in this supplemental IRP.

IV. Transmission reliability evaluation of HDS

Proper accounting of the impact of distributed solar dispatch is required in the transmission planning models because it ensures an accurate transmission needs assessment. Moreover, the MISO 2021 capacity expansion model shows economic potential for 3,400 MWs of DG PV on the low end and 6,000 MW on the high end[43]. Xcel and MISO must account for distributed solar in their planning models to stay compliant with NERC standards and portray an accurate transmission needs assessment.

A. Proper accounting of solar dispatch impact leads to accurate transmission needs assessment

Both utility-scale solar and HDS must be dispatched in the MISO transmission planning models to meet NERC Transmission Planning (TPL) and Model Building (MOD) compliance standards. The MISO planning models are used for justifying transmission projects in the MISO region. Proper accounting for the solar dispatch in these planning models ensures that distributed solar is treated in the same manner as any other capacity resource in those models. Which, in turn, ensures accurate transmission needs assessment.

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[43] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

1. Xcel has a NERC compliance obligation to dispatch distributed solar accurately in transmission planning models

For transmission connected solar, MISO proposed to dispatch solar at 31% on average[44]. This assumption for dispatch percentage is the NERC transmission planning standard TPL-001-4 requirement R2.1.2. Since MISO has no experience with distributed solar resources connected to the transmission system yet, there is no discussion on distributed solar dispatch percentages in MISO planning stakeholder committees.

MISO's recent Transmission Expansion Plan (MTEP) 2021 capacity expansion model forecasts 3.42 Giga Watts (GW) of DG PV on the low end and 6.08 GW on the high end in the next 20 years, compared to Xcel's 1,778[45] MW forecast for the next 15 years. This 3,420 Mega Watts (MW) plus DG PV[46] is sited in the MISO economic models for detailed economic and reliability planning in the next few months leading to transmission project recommendation in December 2021.

As the NERC Planning Coordinator, MISO must submit transmission planning models to NERC to stay compliant with applicable transmission planning and model building standards. Hence MISO must dispatch distributed solar forecasted

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[44] MISO Planning Advisory Committee August 12, 2020, agenda item 3e, Wind and Solar Gen Dispatch, slide 5 of 8, https://cdn.misoenergy.org/20200812%20PAC%20Item%2003e%20Wind%20and%20Solar%20Gen%20Dispatch%20Presentation465534.pdf

[45] Figure III-2: High Distributed Solar Adoption Scenario Forecast, Attachment A: Supplement Details, page 39 of 176.

[46] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

in the MTEP 2021 in both reliability and economic planning models to stay compliant.

Xcel, as MISO Transmission Owner (TO), has delegated some of the Transmission Planning (TPL) and Model Building (MOD) responsibility to MISO as part of the coordination and delegation agreement[47]. Hence, Xcel's NERC compliance obligations are tied to MISO's for the dispatch of distributed solar in the planning models.

2. MISO has a FERC compliance obligation with distributed solar

In addition to upcoming FERC Order 2222 compliance, MISO has FERC compliance requirements related to the Dispatchable Intermittent Resource (DIR) tariff for solar. FERC accepted MISO's DIR filing[48] that,

"*require all solar resources that enter commercial operation on or after March 15, 2020 to register and become dispatchable by March 15, 2022, and solar resources in commercial operation prior to March 15, 2020 have the option to become DIRs, but are not required to do so.*"

Xcel's transmission-connected solar with an in-service date on or after March 15, 2020, must become dispatchable by March 15, 2022. Hence Xcel's solar resources are dispatched by the MISO SCED and control room operator starting March 15,

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[47] MISO Compliance Corner website with link to MISO Coordinated Functional Registration document showing TPL-001-4 as part of the agreement with TOs, https://cdn.misoenergy.org//2018-11-28%20Coordinated%20Functional%20Registration_CFR_final298937.pdf

[48] FERC approval of MISO's Solar DIR filing, https://cdn.misoenergy.org/2020-06-09%20171%20FERC%20%C2%B6%2061,203%20Docket%20No.%20ER20-595-000;%20-001452020.pdf

2022. This MISO responsibility should address Xcel's concerns that an HDS scenario[49] leads to reliability concerns for all hours.

This solar dispatchability market benefit is the same benefit Xcel receives with the rest of the MISO market resources.

To summarize, Xcel and MISO need to account for distributed solar in their planning models based on MISO's MTEP 2021 capacity models forecasting for DG PV. Additionally, MISO must stay compliant with the FERC solar DIR tariff. So, distributed solar dispatch impact is another reason for Xcel to account for an HDS future appropriately.

B. Transmission needs would be reduced by HDS locations inside and outside TCMA relative to the Xcel system peak

We know Xcel did not run a detailed transmission limitations study that includes HDS[50]. If Xcel had run a transmission limitations study with HDS, we would have information on the line ratings on transmission lines, transformers, and substations limiting the power transfers in the TCMA with the addition of HDS capacity.

Additionally, as indicated by Xcel's response to Data Request 19-0368 VS ILSR CEF-004[51], transmission projects are identified by MISO utilities in the Twin Cities

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[49] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Footnote # 21, page 38 of 78, “where vast amounts of variable renewable generation and use limited resources are selected – lead to questions regarding the ability of these portfolios to meet customers’ reliability needs across every hour of every day”
[50] Xcel response to 19-0368 VS ILSR CEF-003, “our Integrated Resource Planning process is primarily focused on size, type, and timing of potential future resource additions. As such, we do not examine locational aspects of specific distributed resource additions in the IRP”.
[51] Xcel responses to 19-0368 VS ILSR CEF-010 through 19-0368 VS ILSR CEF-013 also refer to 19-0368 VS ILSR CEF-004.

Zone[52]. If Xcel modeled HDS in transmission reliability models, we would have information on which of the following MISO transmission projects in Table 4 can be deferred or additional ones needed.

Table 4: Twin Cities Zone Transmission Projects

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	No	XEL
2017-TC-N4	Black Dog-Wilson 115 kV Uprate	2017/C>A	11993	No	No	XEL
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	No	XEL
2017-TC-N6	Plymouth-Area Power Upgrade	2018/C>A	14054	No	Yes	XEL
2017-TC-N7	Lebanon Hills 115 kV	2018/A	12211	No	No	GRE
2019-TC-N1	Red Rock Transformer Uprate	2018/A	14844	No	No	XEL
2019-TC-N2	South Afton Substation	2019/A	15730	No	No	XEL
2019-TC-N3	East Metro Area Upgrades	2019/A	15877	No	No	XEL

52 See section 6.6.1, http://www.minnelectrans.com/documents/2019_Biennial_Report/html/Ch_6_Needs.htm#sec6.6

With the more than 3,000 MW of DG PV projected to be added to MISO capacity expansion models, Xcel and the rest of MISO's Minnesota utilities must tackle this transmission reliability challenge in MTEP 2021.

Additionally, Xcel did not model import and export analysis with and without HDS[53]. Also, LOLE analysis was not conducted for capacity inside the TCMA and outside the TCMA[54]. As a result, we don't have a quantification of reliability benefits of HDS and we don't know if the transmission needs are accurate inside the Twin Cities Zone of Minnesota Electric Transmission Planning website.

C. Xcel should quantify the diversity in TCMA substations peak demand hours.

Footprint diversity is a benefit that occurs when Minnesota's peak demand hour does not occur at the same time as Michigan's peak demand hour (both states are in the same MISO market). This peak demand diversity allows MISO operators to dispatch resources for Minnesota, and then, when a peak occurs in Michigan – procure resources for Michigan.

Similarly, for the purposes of this IRP– Xcel should quantify the diversity benefit provided by the potentially varying peak demand hour at different substations in the TCMA relative to the Xcel system peak.

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[53] Xcel response to 19-0368 VS ILSR CEF-019, "We interpret "import/export analysis" to mean analyses on import and export limits. We have not analyzed import and export limits both with and without HDS."

[54] Xcel response to 19-0368 VS ILSR CEF-017, "We have not conducted an LOLE analysis that replaces some or all imports into the TMA with capacity added inside the TMA".

Xcel Data Request responses # 22 and 23 show both past and future peak demand hours for historical data. In this data, hours ending 16 and 17 are a common denominator.

And in Xcel's Integrated Distribution Plan – Annual Update, Attachment A – Page 4 of 26, Xcel states:

"*Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe.*"

This indicates that most solar output occurs hour ending 16 and Xcel system peak demand hours are those ending 16 and 17. Knowing this historical information, Xcel can store solar energy before the hour ending 16 and discharge during the 4-hour peak window of the hour ending 17 through 20. That reduces the stress on the transmission system.

Additionally, from Xcel IRP, Attachment A: Supplement Details, VI. Resource Attributes, page 109 of 176:

"*substantial solar development exacerbates the trajectory of evening ramping needs, as net demand can increase rapidly over a short period of time when solar output declines and customer demand increases simultaneously*".

Hence, Xcel should quantify the impact of HDS on the transmission system around the TCMA. The transmission system around the TCMA would not be stressed when the Xcel system peaks. Historically Xcel demand did not peak at the same time as MISO zone 1 peak, as the table below illustrates.

Table 5 shows that when the NSP system peak is compared against the MISO zone 1 peak, out of the 14 years of comparable data, in 13 instances – the NSP system peaked at a different hour than the MISO zone 1 peak. So, 93% (13 divided by 14) of time NSP system peaked at a different hour than MISO zonal peak. This peak

Table 5: NSP System Peak comparison with MISO Zone 1 Peak Hour

NSP 60-minute Peak Demand				MISO Zone 1 Peak		
Year	Date	Hour-ending Central Time	Hour-ending. (MISO EST)	Date	Hour-ending. (MISO EST)	
2002	30-Jul	1600	1700	no data		
2003	20-Aug	1700	1800	no data		
2004	21-Jul	1600	1700	no data		
2005	12-Jul	1700	1800	1-Aug	1700	
2006	31-Jul	1600	1700	31-Jul	1600	
2007	26-Jul	1400	1500	9-Aug	1700	
2008	29-Jul	1400	1500	29-Jul	1400	
2009	23-Jun	1400	1500	23-Jun	1400	
2010	9-Aug	1700	1800	9-Aug	1600	
2011	20-Jul	1700	1800	20-Jul	1700	
2012	2-Jul	1700	1800	2-Jul	1500	
2013	26-Aug	1700	1800	26-Aug	1500	
2014	21-Aug	1700	1800	21-Jul	1500	
2015	14-Aug	1600	1700	14-Aug	1600	
2016	20-Jul	1700	1800	20-Jul	1700	
2017	17-Jul	1700	1800	17-Jul	1800	
2018	29-Jun	1700	1800	12-Jul	1700	

time diversity should not be discounted when transmission reliability is modeled.

To summarize, the TCMA would peak at a different time than the NSP system peak. Hence, the HDS impact on reducing the TCMA's transmission system's stress should not be discounted.

IV. Conclusions

The Rakon Energy report took a deep dive into the modeling of HDS in NSP's SIRP. The scope of this report is to evaluate several considerations for high penetration DG impacts on the Company's system, including opportunities within the larger MISO market and how to ameliorate challenges and leverage opportunities. Here are the five main conclusions of this report.

First, NSP must improve its planning to include additional distributed resources and treat them as a “central element to the utility’s optimized plan.” In fact, due to market changes, technology development, and federal policy including FERC Order 2222, it is inevitable that greater distributed resource development will occur and will need to be accommodated by NSP plans. Planning for greater distributed resource penetration now allows efficient optimization rather than inefficient after-the-fact adjustments to the Company’s resource plans.

Second, distributed resources interconnected to Xcel’s distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. Focusing on distributed resources would allow Xcel to integrate higher levels of renewable resources, in contrast with a focus on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.

Third, MISO is currently modeling more than 3,000 MWs of DG PV in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that NSP should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.

Fourth, distributed solar, especially distribution connected DG within the Twin Cities Metro Area should have a higher Effective Load Carrying Capability than utility scale solar connected at transmission to remote nodes. Differences in the ELCC of resources has been shown to vary by interconnection node. Xcel and

MISO should jointly determine the capacity value of distributed resources through a locational capacity value ELCC.

Lastly, this report points out that that distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value. The Commission should require Xcel to integrate distribution, transmission, and resources as part of its IRP to meet system's reliability needs most effectively, rather than through balkanized planning. High density distributed resources will produce higher locational capacity in and around the Twin Cities Metro Area and should be considered separately from other portions of NSP's service territory.