STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

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

In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program	MPUC DOCKET NO. E002/M-25-378

INITIAL COMMENTS OF COOPERATIVE ENERGY FUTURES, ENVIRONMENTAL LAW AND POLICY CENTER, INSTITUTE FOR LOCAL SELF-RELIANCE, SOLAR UNITED NEIGHBORS, AND VOTE SOLAR

December 10, 2025

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I. INTRODUCTION AND SUMMARY

Cooperative Energy Futures, Environmental Law and Policy Center (ELPC), Institute for Local Self-Reliance (ILSR), Solar United Neighbors (SUN), and Vote Solar file these initial comments recommending that the Commission modify Xcel's proposed Capacity*Connect program prior to approval. Without our recommended modifications, the submission will fail to fulfill the Commission's Integrated Resource Plan (IRP) Order or prove cost-effective.

When we first learned of Xcel's interest in the Distributed Capacity Procurement (DCP) concept via its August 9, 2024 comments in its IRP proceeding, we were enthusiastic. As described further below in Section II, our organizations, in various combinations, have been advocating for years for such treatment of distributed energy resources (DER) as a resource in Xcel's IRPs, integrated distribution plans (IDPs), and rate cases. And the Commission has made meaningful progress in this direction. For example, in its 2019 IRP Order, the Commission directed Xcel to take steps to "better align distribution and resource planning," including to: "[i]mprove non-wires alternative analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs"; and "[p]lan for aggregated distributed energy resources to provide system value including energy/capacity value during peak hours."[1] And in its IDP Requirements, the Commission has specified two of its core goals as: "[e]nable greater customer engagement, empowerment, and options for energy services"; and "[m]ove toward the creation

[1] Minnesota Public Utilities Commission, *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, Order Pt. 9, at 34 (Apr. 15, 2022) ("2019 IRP Order").

of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies."[2]

Therefore, we were pleased to see Xcel share our perspective in its August 9 IRP comments, stating, for example: "Integrating DERs into our system planning processes—determining the best customer locations for DER and including customer-sited generation and storage as a grid asset—helps deliver benefits including engaging customers, increasing capacity resources, accelerating the pace of resource deployment, and lowering the net cost to the grid."[3] In our comments on the IRP settlement, we continued to support the DCP and offered recommendations on how to fully leverage DERs to meet energy and capacity needs, including through a complementary third-party Virtual Power Plant (VPP) program.[4]

When we reviewed Xcel's Capacity*Connect proposal filed on October 3, 2025, we continued to find much to support in Xcel's vision for its growing use of distributed energy resources. As Xcel states in its Petition: "C*C represents a step-change in how Xcel Energy and other utilities are beginning to incorporate distributed energy resources into system planning and operations. C*C assets could be used to offset peak load, mitigate curtailment of renewables, and support more renewables on the system, meet bulk system capacity needs and participate in Midcontinent Independent System Operator (MISO) markets, and more. Through the evolution of C*C, the Company is seeking to identify the processes, tools, and capabilities that may allow us to co-optimize benefits between the bulk system and distribution system."[5]

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[2] Minnesota Public Utilities Commission, In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Docket No. E-002/M-23-452, Order (Dec. 3, 2024) (Minnesota Integrated Distribution Planning Requirements for Xcel Energy updated and attached to Order) ("2023 IDP Order").
[3] Docket No. E002/RP-24-67, *2024-2040 Upper Midwest Integrated Resource Plan*, Xcel Energy Initial Comments, 12 (Aug. 9, 2024).
[4] Docket Nos. E002/RP-24-67, *2024-2040 Upper Midwest Integrated Resource Plan* & E002/CN-23-212, *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, DSP Initial Comments, 4-9 (Dec. 4, 2024).
[5] Xcel Petition at 4.

However, we were disappointed that Xcel intends for Capacity*Connect to limit Phase 2 to resources prioritizing bulk-power value, i.e., energy and capacity value on the transmission system through MISO. As proposed, Phase 2 fails to advance distribution value and develop meaningful insights for how to co-optimize distribution and bulk-system benefits. This failure is inconsistent with Xcel's own framing for the program and the Commission's direction in recent orders. While it appears that Xcel continues to aspire to these goals in future Phases 3 or 4, the Company does not expect to begin to address them until 2031, at the earliest and has provided very limited information on how it will progress towards them. In addition, in its Petition, Xcel failed to meaningfully address the opportunity for customer and third-party DER ownership, either in the context of the front-of-the-meter (FTM) resources envisioned in Capacity*Connect, or within a separate behind-the-meter (BTM) Distributed Power Plant (DPP) program (also known as a Virtual Power Plant or VPP program).[6] This failure is also inconsistent with the Commission's prior orders, including particular Order Point 23 from its most recent IRP Order requiring it to evaluate alternative ownership arrangements.

We recommend that the Commission require Xcel to take concrete steps to advance distribution value in Phase 2 by July 1, 2027, which we describe in more detail within our Recommendation 1 in Section III.1. Such modifications will allow Xcel to meet system needs, improve the benefit-cost ratio for the program, and address escalating distribution costs by strategically deploying cost-effective DERs. These modifications would also help to justify Xcel's proposed Limited Grid DERMS investment. They would position Xcel to scale up the Capacity*Connect program in Phase 3. In addition, we recommend the Commission establish a timeline and requirements for third-party participation in the Capacity*Connect, such that Xcel

[6] These terms—DPP and VPP—are interchangeable. We have primarily used VPP in prior comments, testimony, and other filings, and primarily use DPP in these comments. In all cases, we refer to the same concept.

begins to solicit third-party-owned front-of-the-meter assets by July 1, 2027, as we describe in more detail within our Recommendation 2 in Section III.1. We believe such third-party participation will help to drive down program costs. Finally, we recommend that the Commission require Xcel to work with stakeholders to develop and file a complementary behind-the-meter Distributed Power Plant program, as discussed in our Recommendation 3 in Section III.1. Given growing demand, including from large-load customers and electrification, plus escalation of distribution costs, we urge the Commission to require Xcel to adopt cost-effective resource solutions through DPPs, which have been successfully deployed by its sister company in Colorado and utilities nationwide (and globally). In addition to helping the Company meet its resource needs, such a behind-the-meter Distributed Power Plant program could also directly benefit customers through improved resilience, direct bill reductions for participating customers, and customer empowerment in ways that Capacity*Connect does not.

As we explain in Section III, we recommend the Commission adopt this package of modifications to Capacity*Connect prior to approval.

II. BACKGROUND AND CONTEXT

For more than half a decade, the Commission has advanced a vision for how Xcel Energy should plan and operate its system in Minnesota in ways that integrate and optimally leverage distributed energy resources. Across Xcel's integrated resource plans, integrated distribution plans, and rate cases, our coalition[7] has consistently pressed to further this vision, urging the Commission and the Company to treat distributed energy resources—including customer-sited

[7] Under various iterations—including the Distributed Solar Parties (DSP), Community Power–ELPC–Vote Solar (CEV), the Grid Equity Commenters (GEC), the Just Solar Coalition (JSC), and the Joint Intervenors (JIN)—our participants have included Vote Solar and the Environmental Law & Policy Center in all cases, joined at different times by Cooperative Energy Futures, the Institute for Local Self-Reliance, Community Power, Minnesota Interfaith Power & Light, Sierra Club, and, for these Capacity*Connect comments, Solar United Neighbors.

and community-owned solar, storage, demand response, electric vehicles, and other flexible loads—as real, selectable system resources rather than passive "load modifiers." We have argued, and the Commission has recognized, that these resources are capable of providing a full stack of grid services, including:

- Distribution services, such as deferring or avoiding feeder and substation investments, improving hosting capacity, managing voltage, and providing resilience at the neighborhood scale;
- Transmission and bulk-system services, including peak reduction, capacity value, and ancillary services that can reduce the need for conventional generation and transmission upgrades; and
- Equity and energy-justice benefits, including improved reliability in historically under-served communities, reduced energy burden, and new pathways for community ownership and wealth-building.

At the same time, integrated resource planning and integrated distribution planning must be treated as two parts of a larger integrated planning framework. Where cost effective, distribution-connected resources should be prioritized as a tool to reduce costly and slow-to-deploy traditional bulk system investments, including within Xcel's IDPs. Likewise, IRP portfolios should include DERs that are designed to provide utility services and DERs that primarily serve customer load (BTM resources). Xcel and the Commission should evaluate DER portfolios side-by-side with traditional generation, transmission, and distribution investments, and embed equity and energy justice into those decisions rather than treating them as afterthoughts.

The October 2025 Capacity*Connect proposal is best understood in this context, as a critical step on the path the Commission has laid out over the past 6+ years. It is Xcel's first attempt to institutionalize one part of the integrated planning framework in which DERs are co-optimized to provide capacity and grid services. The following subsections summarize the key steps in that evolution and demonstrate the strength and consistency of the evidence and arguments supporting it.

A. 2019 Xcel IRP (Docket No. E-002/RP-19-368): Introducing "Distributed Generation as a Resource"

In Xcel's 2019 IRP, the Distributed Solar Parties (Vote Solar, ELPC, ILSR, and Cooperative Energy Futures, represented by Earthjustice) identified a fundamental shortcoming in traditional IRP modeling: Xcel (like all other utilities at the time) treated distributed generation (DG) purely as an exogenous load reduction rather than as a resource its planning model could choose. We proposed and developed a specific "Distributed Generation as a Resource" (DGR) construct, under which DG would be represented as discrete resource bundles in the capacity-expansion model, with defined costs and performance characteristics, just like utility-scale solar or wind.

Using this construct, we demonstrated that portfolios with higher levels of DG could lower system costs, avoid or delay certain fossil additions, and reduce emissions, while leveraging customer and community capital instead of traditional rate-based assets. We also highlighted the local economic and equity benefits of DG, including community-owned projects and alignment with municipal clean-energy goals.

Order Point 15 of the Commission's 2019 IRP Order directed the Company to work with stakeholders to develop a model for distributed generation as a resource, along the lines of what we proposed.

> Xcel shall work with stakeholders to develop a modeling construct that enables Xcel, as part of its next resource plan, to model solar-powered generators

connected to the company’s distribution grid as a resource. Xcel and stakeholders shall address the following factors in developing the modeling construct:

> A. Using a “bundled” approach as is used to model energy efficiency and demand response.
>
> B. The costs borne by the utility and the costs borne by the customer.
>
> C. Cost effectiveness tests.
>
> D. Other topics as identified by stakeholders. Xcel shall include improved load flexibility and demand response modeling methodologies prospectively, including in its next resource plan.

This work laid the conceptual foundation for treating DERs as a resource in Integrated Resource Plans. The Commission firmly established that DERs should be treated as a selectable capacity resource and that the Company’s planning tools can and should optimize DER portfolios alongside conventional resources.

1. CUB’s Contribution to Understanding the Role of DER

One other notable contribution in the 2019 IRP was the Citizen Utility Board’s (CUB) alternative “Consumers Plan,” developed with Vibrant Clean Energy using the WIS:dom-P co-optimization model.[8] CUB’s Consumers Plan showed that the lowest-cost decarbonization pathway for Xcel’s system requires a substantial build-out of resources connected to the distribution grid, particularly storage. CUB’s Consumers Plan proposed to retire the coal fleet within five years and replace it with wind, utility-scale solar, and a very large portfolio of distributed solar and batteries, while achieving deeper emissions reductions and lowering total system costs and retail rates. By 2035, the model proposed roughly 2.6 GW of distributed PV and 1.4 GW of 8-hour battery storage, all sited on the distribution system (69 kV and below),

[8] Docket No. E-002/RP-19-368, *In the Matter of Northern States Power Company’s d/b/a Xcel Energy 2020–2034 Upper Midwest Integrated Resource Plan*, Citizens Utility Board of Minnesota, Initial Comments of the Citizens Utility Board of Minnesota (Feb. 11, 2021).

alongside additional utility-scale renewables. All of the new storage selected by WIS:dom-P was on the distribution grid, operating behind 69-kV substations to discharge during high-demand periods and reduce the peak load seen by bulk generation. In the WIS:dom-P modeling, distributed storage worked in concert with distributed solar—approximately 45% of total solar in the NSPM region in the Consumers Plan—to meet demand with lower transmission losses and to defer distribution system upgrades even as load grows due to electrification.

CUB's comments in this 2019 IRP underscored that this robust portfolio of distribution-connected resources is not incidental; it is a core driver of the plan's cost and reliability performance. WIS:dom-P explicitly co-optimized the distribution system with utility-scale generation and transmission, using DER to reshape and shift load at the "grid edge," increase hosting capacity either through targeted upgrades or distributed storage, and minimize energy flows and back-feed from the distribution system. As a result, DERs significantly reduce the effective peak demand the bulk system must serve. Using 2019 numbers, Xcel's modeled peak falls to about 6,900 MW in 2040, roughly 25% below the then-current level—while allowing the system to meet all hours reliably with no new fossil generation. CUB concluded that a substantial expansion of distributed solar and distribution-level storage, coupled with integrated distribution planning and appropriate DER valuation, is a cost-effective, consumer-beneficial way to achieve deep decarbonization, lower bills, and defer traditional wires investments, and that Xcel and the Commission should plan explicitly for this distribution-connected portfolio rather than treating DER as a passive, exogenous factor.

B. 2019 Distribution Planning (Docket No. E-002/M-19-666): IDP, Non-Wires Alternatives, and DER Enablement

In parallel with the 2019 IRP, our comments in Xcel's early distribution-planning proceedings—filed by ELPC and Vote Solar—framed the Integrated Distribution Plan as the venue where Xcel must begin treating DER as non-wires alternatives (NWAs) to traditional grid investments.[9] We urged the Commission to require:

- Systematic NWA screening for larger distribution projects, with transparent criteria for when DER portfolios must be evaluated as alternatives or complements to wires solutions;
- Clear use cases tying grid-modernization investments (smart inverters, communications, controls, advanced meters) to specific ways DER can relieve constraints, improve hosting capacity, and enhance reliability; and
- Coordination between IDP outcomes and IRP resource choices, given that distribution constraints and DER potential directly affect resource needs and costs.

These filings anchored DER as a potential distribution-level grid service provider and firmly linked distribution planning to resource planning.

C. 2021 Xcel IDP (Docket No. E-002/M-21-694): DERMS, Equity, and Community-Grounded Planning

In the 2021 IDP, the coalition appearing as Community Power–ELPC–Vote Solar (CEV) built on that foundation and focused on the operational architecture needed to make DER portfolios usable as grid resources.[10]

Our comments emphasized that the IDP process had significantly increased transparency into distribution budgets and projects but now needed to integrate equity, community

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[9] Docket No. E-002/M-19-666, *In the Matter of Xcel Energy's 2019 Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Environmental Law & Policy Center and Vote Solar, Initial Comments of the Environmental Law & Policy Center and Vote Solar on Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request (Mar. 17, 2020).

[10] Docket No. E-002/M-21-694, *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, Community Power, Environmental Law & Policy Center, and Vote Solar, Initial Comments of Community Power, Environmental Law & Policy Center, and Vote Solar (Feb. 25, 2022).

engagement, and DER enablement into project selection and prioritization. We scrutinized Xcel's proposed DERMS, Distributed Intelligence, and resiliency pilots, arguing that:

- These investments must be tied to defined use cases where DER portfolios are actually deployed to provide services such as voltage support, peak reduction, and resilience; and
- Customer- and community-owned DER must be able to participate through these platforms, not just assets directly controlled by the utility.

We reiterated the need for a structured NWA framework so that DER solutions are considered systematically wherever they are cost-effective, rather than only in ad hoc pilots. This docket began to specify the technical and organizational infrastructure—DERMS, controls, and community-grounded planning—needed to orchestrate DER portfolios as Distributed Power Plants.

In the July 26, 2022 Order on Xcel's 2021 IDP, the Commission essentially adopted our recommendation to change the IDP filing requirements so that Xcel must explicitly address aggregated DER and DER providing grid services.[11] Responding to CEV's proposal to modify filing requirement 3.A.5, the Commission "concur[red] on the reasonableness" of our suggested changes and modified 3.A.5 to require Xcel to explain how distribution planning is coordinated with the IRP, including five specific items. The new subpart (e) now directs Xcel to plan "for aggregated distributed energy resources to provide system value including energy/capacity during peak hours," which is exactly the type of aggregated, grid-service DER portfolio we had urged the Commission to recognize.

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[11] Docket No. E-002/M-21-694, *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project (July 26, 2022).

D. 2023 Xcel IDP (Docket No. E-002/M-23-452): Grid Equity and DER

In the 2023 IDP, the Grid Equity Commenters (ELPC, Vote Solar, Cooperative Energy Futures, and Sierra Club) deepened the connection between DER, distribution planning, and energy justice.[12]

Our comments documented racial and economic disparities in reliability and service quality across Xcel's service territory and argued that distribution planning and capital budgeting must explicitly address those inequities. We described the role of DER in advancing energy justice, including:

- Lowering bills and energy burden through targeted deployment of DER and efficiency;
- Improving resilience and reliability in communities that have historically experienced the worst service; and
- Expanding access to clean energy and community ownership in underserved neighborhoods.

We also explicitly linked DER to distribution budgets, calling on Xcel to "take advantage of areas where its budgets can be reduced, such as by leveraging DERs," when planning capacity and reliability projects. We emphasized the importance of hosting-capacity analysis and equitable access to DERs and called for a clear DERMS roadmap with stakeholder engagement to ensure that residential and community resources—not only utility-controlled assets—can provide grid services.

[12] Docket No. E-002/M-23-452, *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Initial Comments of Grid Equity Commenters (Cooperative Energy Futures, Environmental Law & Policy Center, Sierra Club, and Vote Solar) (Mar. 1, 2024).

The Commission approved Xcel's 2023 Integrated Distribution Plan as meeting current requirements but declined to broadly pre-approve DER-related capital investments and instead focused on process refinements.[13] It required Xcel to implement a 15 percent PV dependability factor and continue using Planned Net Load for N-0 risk analysis while working with stakeholders to refine the methodology, including how dependability factors are defined and applied. The Commission declined to authorize specific DERMS spending, instead directing Xcel to conduct DERMS, cost-benefit, hosting capacity, and Planned Net Load workshops and to bring any concrete DERMS proposals, including cost recovery, in future proceedings. It also relied on ongoing and future IDPs and related dockets, rather than this order, to advance hosting-capacity targeting, equity considerations, and improved treatment of DER and load flexibility in forecasting and non-wires alternatives analysis.

By this point, the Commission had issued several orders, based on a strong body of evidence, regarding using DER portfolios as tools for both distribution-level grid services and equity outcomes, strengthening the case for a formal mechanism to procure these resources, such as a Distributed Power Plant.

E. 2021 Xcel Electric Rate Case (Docket No. E-002/GR-21-630): Incorporating Energy Justice into Ratemaking and Distribution Investments

In this Xcel electric rate case, we intervened as the Just Solar Coalition (JSC), consisting of Community Power, Cooperative Energy Futures, Minnesota Interfaith Power & Light, and Vote Solar, jointly represented by ELPC. JSC's witnesses, including Dr. Lorenzo Kristov, Dr. Gabe Chan, Karl Rábago, and Cody Davis, extended the themes from IRP and IDP into the ratemaking context.

[13] 2023 IDP Order.

JSC's witnesses presented an explicit energy-justice and equity framework for Commission decision-making, showing how within-class disparities in reliability, disconnections, and energy burden should inform what is considered "just and reasonable." They connected the Commission's IDP directives to cost recovery, arguing that distribution investments should be evaluated in light of non-wires alternatives, DER potential, and hosting-capacity constraints, not only traditional engineering criteria. They also described how customer- and community-owned DERs could help address inequities in service quality and energy burden if grid-modernization investments are designed to enable DER portfolios to provide grid services, rather than focusing solely on utility-controlled devices.

This case firmly established that equity and DER belong in rate cases and started to connect IDP outcomes to what Xcel is allowed to collect in base rates. Specifically, the Commission recognized the importance of the four "Energy Justice" tenets—Recognition, Procedural, Distributional, and Restorative Justice—and explicitly found that these concepts are relevant to determining just and reasonable rates.

> The Commission recognizes the importance of Energy Justice tenets as recommended in its proceedings, including general rate cases. While the Commission must decide issues in each rate case based on the record before it in such proceedings, the Commission finds that the tenets of Energy Justice recommended by Just Solar are relevant to setting rates in this proceeding.[14]

F. 2024 Xcel Electric Rate Case (Docket No. E-002/GR-24-320): Continuing to Incorporate Grid Equity into Ratemaking and Distribution Investments

In the current Xcel electric rate case, our coalition appears as the Joint Intervenors (JIN), including Cooperative Energy Futures, ELPC, Minnesota Interfaith Power & Light, and Vote

[14] Docket No. E-002/GR-21-630, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Electric Rates in Minnesota*, Findings of Fact, Conclusions, and Order (July 17, 2023).

Solar. In this case, Will Kenworthy's and Dr. Gabe Chan's direct testimonies build directly on the 2019–2023 IRP and IDP proceedings and on the 2021 Xcel rate case work.

Their testimony brings the grid-equity analysis into the rate case, demonstrating how distribution investments, reliability outcomes, and rate design interact with documented disparities across communities. Mr. Kenworthy's testimony in particular scrutinizes Xcel's proposed distribution capacity and hosting-capacity projects, arguing that:

- Large capital programs should be evaluated against DER-based alternatives and aligned with the integrated distribution-planning and NWA frameworks developed in prior dockets; and
- The Company should be preparing to use DER and Distributed Power Plant portfolios as tools to manage load growth—including new data centers and other large loads—and to improve reliability in underserved communities.

The testimony also includes a dedicated discussion of Distributed Power Plants and DER orchestration, explaining how portfolios of distributed solar, storage, demand response, EVs, and controllable loads can be deployed to provide both bulk-system capacity and local reliability and equity benefits, and arguing that such portfolios should be treated as part of the same solution set as traditional capital projects. It further addresses large-load tariffs and data centers, reinforcing our long-standing position that new large loads must cover their incremental costs and should be paired with additional clean capacity rather than simply increasing strain on existing infrastructure.

Where the 2021 Xcel rate case established the principle that equity and DER must be considered in rate cases, the current 2024 Xcel rate case pushes further and effectively sets the stage for a formal distributed capacity procurement framework, arguing that DER/DPP portfolios should be considered when the Commission decides which grid investments are prudent and how costs are allocated.

G. 2024 Xcel IRP and Settlement (Docket No. E-002/RP-24-67): Formalizing Distributed Capacity Procurement

In Xcel's 2024 IRP, the Distributed Solar Parties again filed detailed comments updating the DG as a Resource methodology and evaluating how Xcel implemented DG modeling in this new planning cycle.[15] Those comments argued that DG and other DER are still not being fully optimized in resource portfolios and introduced Distributed Power Plants as a necessary evolution: instead of viewing distributed resources as isolated load modifiers, Xcel should model aggregated portfolios of DER—combining solar, storage, demand response, and flexible loads—as dispatchable resources providing capacity and reliability services.

On the same day that parties, including the Distributed Solar Parties, filed comments on the 2024 IRP (August 9, 2024), Xcel also filed comments introducing the Distributed Capacity Procurement concept.[16] Shortly thereafter, a settlement emerged which included a commitment by the Company to file a DCP by October 2025, with additional filing requirements from the Commission.

On December 4, 2024, the Distributed Solar Parties' settlement comments connected this DCP commitment to the long-standing DG-as-Resource and DPP concepts that we have now advocated for in multiple dockets.[17] Notably, the settlement agreement did not address the shortcomings in Xcel's modeling of distributed solar uptake, which may have contributed to the

[15] Docket No. E002/RP-24-67, *2024-2040 Upper Midwest Integrated Resource Plan*, Initial Comments of the Distributed Solar Parties (Aug. 9, 2024).
[16] Docket No. E002/RP-24-67, *2024-2040 Upper Midwest Integrated Resource Plan*, Comments of Northern States Power Company d/b/a Xcel Energy (filed Aug. 9, 2024).
[17] Docket Nos. E002/RP-24-67, *2024-2040 Upper Midwest Integrated Resource Plan* & E002/CN-23-212, *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, Comments of the Distributed Solar Parties on the Proposed Settlement (Dec. 4, 2024).

absence of solar energy from the DCP proposal, which focuses, at least in Phase 2, on battery storage.

H. Summary of the Context and History

Viewed in the context of this history, the October 2025 Capacity*Connect proposal is not an isolated pilot or one-off program. Rather, it represents the next logical step in an evolution of a broader effort to co-optimize DER across multiple planning processes and utility functions to benefit all customers. Collectively, the prior proceedings discussed above create a strong and coherent record for using DER as full-stack grid resources—resources that can provide distribution, transmission, and bulk-system services while advancing equity and energy justice. Capacity*Connect is best evaluated as part of that larger picture: as Xcel's first formal implementation of a DER as a resource framework that must now be aligned with the IRP/IDP integration, DER valuation, and equity commitments that the Commission has been steadily building toward since 2019.

While the Capacity*Connect program represents an important step, it is only one component of a broader DER strategy needed to unlock the full potential grid benefits of DER. As discussed further in these comments, the Commission should modify Capacity*Connect to focus on maximizing distribution infrastructure value, and also require the Company to implement complementary programs that support both behind-the-meter resources—such as Distributed Power Plants (DPPs)—and front-of-the-meter, third-party owned, distribution-connected solar and storage that prioritize bulk power system benefits. To ensure effectiveness, the Commission should modify Phase 2 to concentrate specifically on delivering distribution value, while further initiatives are developed to realize the full spectrum of DER benefits across the grid.

III. RESPONSES TO TOPICS OPEN FOR COMMENT

1. Should the Commission approve, modify, or deny Xcel's proposal for Capacity*Connect Phase 2?

We recommend that the Commission modify Xcel's proposal for Capacity*Connect Phase 2 to make the program cost-effective and to fulfill in the near-term the intended purpose of capturing distribution value with distributed resources. As described in more detail below, prior to approving Capacity*Connect, we recommend the Commission:

1. Require Xcel to take concrete steps to advance distribution value in Capacity*Connect Phase 2 by July 1, 2027, with an eye toward full realization and scaling up in capacity in Phase 3;
2. Establish a timeline and requirements for third-party participation in the Capacity*Connect, such that Xcel begins to solicit third-party-owned front-of-the-meter assets by July 1, 2027; and
3. Require Xcel to work with stakeholders to develop and file a complementary behind-the-meter Distributed Power Plant (DPP) program by July 1, 2026.

Without these modifications, Capacity*Connect Phase 2 does not make adequate progress towards the Commission's goals in recent IRPs and IDPs of utilizing DERs as a resource, as discussed above in Section II. Currently, rather than making progress towards leveraging the distribution value of DERs, the program utilizes the participating storage assets for their bulk-system value alone, though it recognizes it may achieve incidental distribution value in doing so. While it may be novel that Xcel proposes to locate these assets on the distribution system, and thereby avoid transmission interconnection issues, the Company does not meaningfully explore how to co-optimize their distribution value. Xcel appears to envision a more innovative, distribution-aware program in Phases 3 and 4. For example, in describing Phase

3, Xcel states that it “would seek opportunities to stack additional distribution value streams on top of the bulk system dispatch planned for Phase 2. Siting in this phase could consider additional data points – informed by lessons learned in Phase 2 – to maximize distribution system benefits.”[18] However, in its Petition these future phases are conceptual, with limited information regarding how the Company expects to achieve them. Moreover, Xcel does not expect to begin to address these Phase 3 goals until 2031, six years from now. The Company should develop the tools for capturing distribution system value in Phase 2, in the near term, and specify how the coordination of different function uses of the energy storage assets will evolve.

Moreover, as proposed, the benefit/cost ratio for the program is below one, even under the optimistic assumptions in Xcel’s benefit-cost analysis. If modified to prioritize distribution value in Phase 2, the program could achieve greater value for Xcel and its customers and as a result a more favorable benefit/cost ratio. In addition, introducing third-party ownership to the Capacity*Connect program should help to further drive down costs.

Xcel also fails to provide a meaningful analysis of alternative ownerships structures as the Commission required in its most recent IRP Order. Instead, the Company summarily dismisses alternative models without engaging with the potential benefits such models might offer its customers, including, but not limited to, promoting equity. We explain the value that a behind-the-meter customer and third-party Distributed Power Plant program would provide, as a complement to Xcel’s Capacity*Connect offering.

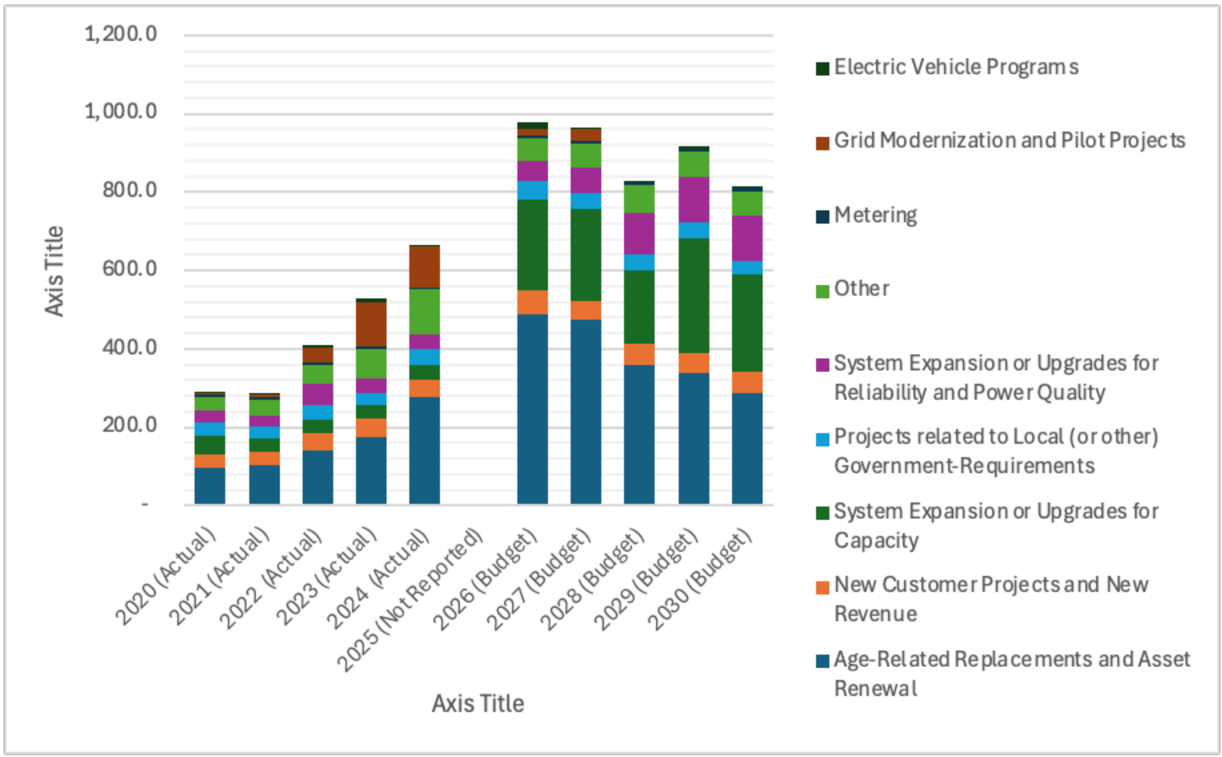
Recommendation 1: Prioritize distribution value in this Phase 2 by July 1, 2027, with an eye toward full realization and scaling up in capacity in Phase 3

In Xcel’s recent rate cases—as in those of other utilities across the region—rapidly rising distribution capital expenditures have emerged as a primary driver of rate increases. Yet, unlike

[18] Xcel Petition at 12.

generation and transmission, where competitive markets and clear planning frameworks provide some discipline on spending, there is still no robust process that systematically tests whether traditional "wires" investments are the most cost-effective way to meet grid needs.

The chart below shows data from the IDP just filed, pulled together from two separate tables (6.1 and 6.3).



Historical and Budgeted Distribution Capital Additions (2020-2030) (2025 data not reported)[19]

Distributed energy resources—especially storage and solar-plus-storage—have the potential to provide precisely this kind of discipline. When deployed in the right locations and operated appropriately, DERs can defer or avoid specific feeder and substation upgrades, alleviate distribution congestion, improve utilization of existing assets, and ultimately reduce the need for future rate-base additions. But that potential will only be realized if the utility explicitly

[19] Docket No. E002/M-25-142, *In the Matter of Xcel Energy's 2025 Integrated Distribution Plan*, 2025 Integrated Distribution Plan, Tables 6.1 and 6.3 (Oct. 31, 2025).

plans for and values DERs as alternatives to wires solutions, and if there is genuine opportunity for both utility-owned and third-party DER projects for delivering distribution services.

Capacity*Connect Phase 2 is, in our view, a critical opportunity to begin building that framework. The Company has described Phase 2 as a program intended to deploy distribution-connected capacity "as part of the distribution system to serve customers system-wide," and to explore use cases that include avoided transmission and distribution value and "distribution net demand reduction."[20] We read these statements to mean that Phase 2 is supposed to be more than a fleet of distribution-connected batteries providing bulk-system capacity through existing MISO mechanisms. It should be the vehicle by which Xcel and the Commission start to operationalize distribution value, using real projects on real feeders as test cases.

<u>Phase 2 as the bridge from concept to practice on distribution value</u>

The Company's petition also acknowledges that the value proposition for Capacity*Connect depends on realizing multiple benefit streams and that there is uncertainty about whether bulk-system and distribution benefits can be delivered at the same time. Xcel notes that dispatching a battery to address a MISO constraint may not always coincide with a distribution constraint,[21] and that Phase 2 is intended to test how these value streams can be coordinated and where conflicts or tradeoffs arise. We agree that this is a central question for the program.

However, as currently proposed, Xcel has not designed Phase 2 to prioritize and test distribution value. Xcel's proposal does not:

- Tie siting criteria directly to identified distribution system needs at specific feeders and substations;

[20] Xcel Petition at 8-9.
[21] Xcel Petition at 37.

- Lay out how the proposed Limited Grid DERMS will be used to co-optimize bulk and distribution objectives; or
- Commit to the analytical work needed to move from a generic placeholder for avoided distribution costs to a Minnesota-specific, locational valuation framework.

Without these elements, Phase 2 risks functioning primarily as a set of distribution-connected resources that provide capacity into existing MISO mechanisms—a useful bulk-system benefit, and a form of risk mitigation if distribution value does not materialize, but far short of what is needed to discipline distribution spending and inform a more mature Phase 3.

Current limitations in distribution valuation

Xcel's own benefit-cost analysis highlights the current limitations in the design of Phase 2. For avoided distribution value, the Company applies a generic estimate of $40/kW-year and explicitly states that, in the absence of an established methodology to calculate a Minnesota-specific avoided distribution value, this is only a "reasonable starting point" and that the actual value could be higher or lower pending additional analysis. That admission is important: it confirms that neither Xcel nor the Commission yet has the tools needed to:

- Quantify near-term, location-specific deferred or avoided distribution investments attributable to DER deployments; and
- Estimate long-run systemwide distribution value from DERs in a way that can be incorporated into planning and cost-effectiveness testing.

In addition, Xcel does not yet have a fully developed locational distribution value mechanism that links DER siting and operation to specific feeders, substations, and projects. While Integrated Distribution Plans, hosting capacity maps, and asset condition data provide important building blocks, the Company does not presently use those tools to systematically compare "wires-only" solutions with "DER-enabled" solutions across the portfolio of upcoming projects.

Similarly, the Limited Grid DERMS proposed in this docket is still at an early, conceptual stage. The roadmap attached to the Petition does not satisfy the Commission's IDP Order, as discussed further below. It also does not clearly explain how Phase 2 resources will be dispatched via DERMS to target specific distribution constraints, or how conflicts between bulk-system and distribution needs will be managed and documented.

Taken together, these gaps mean that Phase 2, if implemented as proposed, may deliver meaningful bulk-system capacity value but only incidental or unquantified distribution value. That is not consistent with Xcel's stated program objectives or with the urgent need to introduce competitive, downward pressure on distribution spending.

<u>Tools the Company needs: power flow analysis and marginal distribution cost analysis</u>

To move from placeholder values and qualitative aspirations to quantifiable, Minnesota-specific distribution value, Xcel must undertake two complementary streams of analysis during Phase 2, to be completed by July 1, 2027.

First, **feeder- and substation-level power flow analysis**. For each area where Phase 2 resources are proposed, the Company should use power flow studies to identify:

- Existing and projected constraints on feeders and substations, including capacity, voltage, and reliability issues;
- The traditional wires projects that would be undertaken to address those constraints in a "business-as-usual" plan; and

- How a portfolio of DERs—beginning with Phase 2 storage and solar-plus-storage assets, but ultimately including behind-the-meter resources—could relieve those constraints under realistic dispatch conditions.

These studies should draw directly on IDP data, including load forecasts, asset health assessments, and hosting capacity results. They should not be limited to high-level system averages but should instead be grounded in specific circuits and substations that are already driving or expected to drive distribution capital expenditures. We are aware that the Company has worked with Kevala in the past and are also aware that Kevala has done a very similar analysis in California that could inform the Company's approach here.[22] We recognize that it will take time to develop these analyses and Xcel will have to rely on existing heuristics to site projects in Phase 2, at least initially, as discussed further below. However, the Commission should require Xcel to develop and eventually integrate the results of these analyses in its decisions regarding Capacity*Connect asset locations—potentially later in Phase 2, and certainly in Phase 3 and beyond—to capture distribution value and make the assets and program as cost-effective as possible.

Second, **marginal distribution cost analysis**. Power flow results must then be translated into monetary values through a robust marginal cost framework. That framework should estimate both:

- Short-run, project-specific deferred or avoided costs (for example, deferral of a particular reconductoring project or transformer replacement); and
- Long-run marginal distribution costs that reflect the incremental cost of serving additional load and maintaining reliability over time in different parts of the network.

[22] Kevala, Inc. 2025. California Load Management Standard Avoided Distribution Grid Upgrade Study. Prepared for GridLab. Available at: https://gridlab.org/portfolio-item/ca-load-mgmt-standard.

Combining these elements will allow Xcel to develop feeder- or substation-specific avoided cost estimates—"how much value a MW of DER provides in this location"—that can gradually replace the generic $40/kW-year assumption. Those estimates can then be incorporated into benefit-cost analysis for Phase 2 projects, and later into broader IDP and rate case assessments of distribution capital portfolios.

These two analytical tools are mutually reinforcing. Power flow studies identify where and how DERs can provide distribution services; marginal cost analysis tells us what those services are worth. Both are necessary if DERs are going to function as a credible alternative to wires investments, with opportunities for both utility- and third-party ownership.

<u>Phase 2 should be implemented as a steppingstone, by July 1, 2027, to a more complete valuation of distribution services and significant scaling in capacity in Phase 3</u>

Given these limitations and needs, we recommend that the Commission re-orient Phase 2 around distribution value in three principal ways.

First, Phase 2 siting criteria should be revised to require that utility-owned front-of-the-meter projects be located where the Company expects them to deliver meaningful distribution value, as identified through IDP-informed analysis. That means requiring siting at locations with existing or imminent capacity, reliability, or asset health needs, and where power flow studies indicate that DERs could defer or avoid traditional capital projects.

In some cases, that may mean siting resources on utility property, including at substations, rather than exclusively at commercial and industrial (C&I) customer premises. An exclusive focus on C&I host sites could:

- Miss higher-value locations on the network; and

- Require additional customer payments that would be unnecessary if resources were located on utility-owned property.

We therefore recommend that the Commission direct Xcel to add provision of distribution system value to its "minimum criteria" in this Phase 2 and to consider utility-property siting where it better targets those needs.

Second, given the Company's learning curve and the absence of a mature distribution valuation framework, Phase 2 should be treated as a limited-scale, near-term test bed, not as a fully scaled deployment. Authorizing a smaller initial capacity—on the order of 50 MW rather than 200 MW—would allow Xcel and the Commission to:

- Concentrate on a manageable number of high-value locations;
- Develop and refine the necessary analytical tools; and
- Evaluate real-world operational experience with co-optimizing bulk and distribution benefits before committing ratepayers to a larger Phase 3 portfolio.

Within that smaller portfolio, the Commission should encourage Xcel to design projects as deliberate "test cases" for different use cases, including deferral of specific "wires" capacity investments, BESS utilization for increasing hosting capacity, and coordination with behind-the-meter resources. The Commission should require Xcel to accomplish this Phase 2 test period by July 1, 2027, which would position the Company to significantly scale up the program in Phase 3 and beyond.

Third, if the Commission approves the proposed Limited Grid DERMS investment in this docket, it should make clear that the primary justification for that investment is Phase 2's contribution to learning how to co-optimize bulk and distribution value, not just bulk-system dispatch. The Company should therefore be required to:

- Use the Limited Grid DERMS to dispatch Phase 2 resources in response to identified distribution constraints, not just MISO signals, when feasible;
- Document when and how DERMS dispatch decisions reflect tradeoffs between bulk and distribution needs; and
- Report on the degree to which concurrent benefit streams were actually realized, and what operational or institutional barriers were encountered.

In other words, the Commission should expect the DERMS platform to be used to learn exactly the lessons Xcel says it needs to learn how multiple benefit streams can be captured simultaneously, and under what conditions they cannot.

<u>Regulatory alignment, integration with the IDP, and reporting requirements</u>

Finally, aligning Phase 2 with the Commission's broader distribution planning framework is essential. In addition, and as discussed further below, Xcel's suggestion that Capacity*Connect resources be excluded from Minnesota's Distributed Energy Interconnection Process (DIP) is not appropriate in light of the role these resources are expected to play on the distribution system and the need for a consistent, transparent process for all DERs.

More broadly, the Integrated Distribution Plan is the appropriate venue for detailed DERMS and use-case design, as well as for long-term consideration of distribution valuation methodologies. As discussed further below in response to Question 4, the DERMS roadmap presented in this docket does not, by itself, satisfy the IDP Order's expectations. Instead, we recommend that the Commission:

- Direct that Phase 2 planning, siting, power flow analysis, and marginal cost analysis be integrated with the next IDP cycle;

- Require that future IDPs include explicit discussion of how Phase 2 resources are incorporated into power flow studies and capital planning; and
- Use the results of Phase 2 analysis and operations to inform DERMS design and use cases in the IDP, including designing Grid DERMS and Enterprise DERMS systems in a way that anticipates future use cases for greater integration of DERs and solar plus storage, such as BTM Distributed Power Plant programs.

To ensure that Phase 2 produces actionable information, the Commission should require Xcel, during Phase 2 and in anticipation of future cost-effectiveness review, to:

1. Conduct feeder- and substation-level power flow analysis for each Phase 2 project, comparing wires-only and DER-inclusive scenarios;
2. Develop and apply marginal distribution cost estimates that move beyond a generic $40/kW-year value to Minnesota-specific avoided cost ranges;
3. Provide ex-ante estimates of expected distribution benefits for each project, including deferred/avoided capital projects, reduced losses, or improved hosting capacity; and
4. Report ex post on realized distribution benefits and on how Phase 2 resources were dispatched via DERMS to serve both bulk and distribution objectives.

Recommendation 2: Establish a timeline and requirements for third-party participation in the Capacity*Connect, such that Xcel begins to solicit third-party-owned assets program by July 1, 2027

A firm timeline to introduce third-party participation in Capacity*Connect, as modified to integrate distribution value as discussed above, will preserve essential operational control, and introduce competitive pressure to lower costs and maximize customer benefits. Unlike traditional distribution infrastructure— "poles and wires"—the battery storage that Xcel contemplates for Phase 2 of Capacity*Connect is a relatively novel application of an emerging technology. Xcel and the Commission have recognized that these assets can meet utility system needs, including distribution, transmission, and bulk-system resource needs. While the Company may require a significant degree of visibility into and control over the <u>operation</u> of these assets to do so, nowhere in its application does Xcel justify the need for it to <u>own</u> these assets. We emphasize that ownership is distinct from visibility and control.

From the third-party perspective, Capacity*Connect, if modified to maximize distribution value, can serve to open these distribution deferral value streams to third parties, making these projects financially viable in ways they have not been to date using existing MISO structures. From the ratepayer perspective, introducing third-party participation into Capacity*Connect for these front-of-the-meter assets would help to drive down costs through competitive pressure, while still allowing the Company to monitor and control the assets as needed. Moreover, such third-party participation could serve as a critical check on the Company's inherent incentive to build infrastructure, including any Capacity*Connect assets, since it earns a return on such capital investment. In addition, since such third-party assets would not be rate-based, they would inherently offload performance risks from ratepayers to third parties.

We recommend that the Commission establish a clear timeline towards introducing third-party ownership into the Capacity*Connect program, while recognizing this program is a new undertaking. We suggest that by July 1, 2027, once Xcel has developed the tools described within our Recommendation 1, the Company should begin soliciting third-party Capacity*Connect assets. In the meantime, we recommend the Commission require the Company to develop, in consultation with interested stakeholders, the requirements for such third-party participation. This consultation should include, at a minimum, the rules framework to ensure all utility and non-utility participants have access to the same data (for strategic siting and to evaluate program performance) and follow the same interconnection and application procedures.

Recommendation 3: Require development of a companion third-party behind-the-meter Distributed Power Plant program during Phase 2, to be filed by July 1, 2026

Critically, the Commission should require Xcel to propose a companion, behind-the-meter Distributed Power Plant program that aggregates customer-owned resources through third-party providers. Such programs are being deployed across the country, including in Colorado by Xcel's sister utility. Since they leverage customer investment and third-party technology and innovation, DPPs have proven to be cost-effective (on average creating $2 of customer value for every $1 spent on a program). We have attached an Appendix describing these programs currently operating around the country and have highlighted their best practices that Xcel could implement for the benefit of customers in Minnesota.

While Xcel characterizes its DER deployment as either front-of-the-meter or behind-the-meter and suggests that only after successful FTM battery deployment can customer BTM batteries be aggregated and deployed, this is not the case among similar utilities nor should it be the case for Xcel. This is not an either/or situation, but rather a both/and situation where FTM and BTM resources can work in concert to provide capacity to the grid and create affordable clean, energy solutions for all customers.

In fact, Xcel has recognized the value of BTM resources through its residential battery storage incentive programs. A DPP can further leverage this investment and ensure that BTM resources are working in aggregation at scale to better serve the grid and create value for all customers.

As the programs laid out in the Appendix exemplify, because they aggregate existing customer resources and they use existing technology solutions already available through third-party providers, DPPs can be established in a matter of months and can scale up quickly with the right compensation and program design elements in place.

For these reasons, the Commission should require a filing of a BTM Distributed Power Plant program no later than July 1, 2026, with the aim of ensuring operation by summer 2027.

Discussion of Specific Issues Requested

a. Program design, implementation, and operation

Our discussion of our three recommendations above provides our comments on modifications necessary to program design, implementation, and operation prior to approval.

b. Delivery of system benefits

As discussed above with respect to our Recommendation 1 to prioritize distribution value in Phase 2, we suggest that the Company's current proposal to postpone integrating distribution value until Phase 3 (2031) reflects a significant missed opportunity to realize system benefits, including with respect to congestion, grid utilization, and distribution capacity. Modifying the program to prioritize these benefits is especially critical in light of escalating distribution costs and related increase to rates and detrimental impacts on affordability. In addition, as described above, delivery of system benefits should be explicitly coordinated with Xcel's IDP, including specifically with the feeder-level data and hosting-capacity updates it produces as part of the IDP. We also highlight the potential for siting projects in EJ areas with demonstrated lower reliability, allowing these communities to directly benefit from distribution-level improvements in service.

c. Reporting

Given our recommendations above, we suggest that additional reporting is necessary, including specifically:

- Reporting related to distribution system value as discussed in detail related to our Recommendation 1 above; and
- Updated benefit-cost analysis based on actual distribution benefits delivered using analytical tools developed in Phase 2 as recommended above (marginal cost analysis and power flow analysis).

d. Budget

In these comments, we do not take a position on the appropriate top-line budget for Xcel's Phase 2 proposal; instead, we focus on whether the Company's underlying benefit-cost analysis (BCA) provides a credible basis for those expenditures. The BCA relies on several optimistic and poorly supported assumptions, including transmission and distribution (T&D) deferral benefits that are not clearly tied to specific projects or documented needs, as well as market value assumptions that may overstate revenues and underestimate risk. At the same time, Xcel's analysis does not adequately reflect the locational value of investments and distributed energy resources on the distribution system, which leads to a systematic undervaluation of distribution-level solutions relative to traditional wires projects. The resulting BCA underscores the importance of our Recommendation 1 above to prioritize realizing distribution value in Phase 2. By properly valuing these distribution-level solutions in the ways we suggest, the benefit component of the BCA will increase, making the program more cost-effective for ratepayers. To ensure these benefits materialize as expected, we recommend the Commission require the Company to update its BCA once it develops the analytical tools we recommend in Phase 2, as noted above.

e. Procurement process

We emphasize that any procurement should target and value assets consistent with our Recommendation 1 regarding integrating distribution value. Consistent with our discussion above, we also recommend that Xcel should not limit the program to battery storage but should also incorporate solar-plus-storage assets into its siting and procurement frameworks. In addition, as part of incorporating third-party ownership into the Capacity*Connect as described in our Recommendation 2, we recognize that Xcel will have to develop an additional procurement process to solicit such third-party assets. As noted above, we recommend Xcel develop this process in consultation with interested stakeholders, including parameters around sharing data necessary for third parties to site these assets strategically. We envision that the behind-the-meter DPP described in our Recommendation 3 would be a separate program with a separate tariff for participation, to be developed separately from Capacity*Connect, but as a complement to it.

Regarding siting of utility-owned assets on customer property, as noted above, we suggest that Xcel also explore opportunities to site Capacity*Connect assets on utility-owned property, if it determines that such sites would deliver distribution value. In doing so, Xcel would both realize that distribution value and also avoid the customer payment, which may help to lower project and program costs.

f. Applicability of MNDIP

As noted above, in its Petition, Xcel states that its Capacity*Connect storage assets would not be subject to the Minnesota Distributed Energy Resources Interconnection Process (MNDIP).[23] Xcel should **not** be allowed to exclude its projects from the MNDIP. Excluding Xcel's projects from the MNDIP undermines the essential concept of fairness. All other projects must go through the MNDIP, and so it logically follows that Xcel's projects should also go through the MNDIP in the same manner that other projects must proceed.

[23] Xcel Petition at 18.

Furthermore, allowing Xcel's projects to be excluded from the MNDIP would undermine principles of competitive neutrality, which become especially important when third-party participation is introduced through both Capacity*Connect and a third-party BTP DPP, as we recommend. Proceeding through the MNDIP typically takes 12-18 months and is a somewhat arduous process. Excluding Xcel from this process would give the Company a huge competitive advantage over all other projects. This is especially egregious given that Xcel's claims their projects will use available generation capacity at substations, which would further disadvantage other projects that would be competing for that capacity.

In the Company's response to the Commission Staff's Information Request No. 5 (attached) it states, "The statute repeatedly refers to "on-site" distributed generation, a term that in ordinary usage – and by the context of the statute refers to customer-sited resources located on the customer's premises." The Company uses this statement as a justification for exempting Xcel's Capacity*Connect projects from the MNDIP. They claim that the Capacity*Connect projects are not "on site" and all other developers projects are considered "on site." However, the Capacity*Connect projects will also be located on customer premises, therefore this distinction is meaningless.

Ultimately, if Xcel were exempted from the MNDIP, it would allow Xcel to effectively bypass the queue and get in front of other third-party-owned projects that are currently in the queue. This would be deeply unfair and undermine the entire concept of the queue as an attempt to fairly allocate limited capacity. Such an outcome is especially problematic when seeking to encourage participation by third parties in either Capacity*Connect or a separate BTM DPP program, as we recommend.

We also note that there is an active “Flexible Interconnection” work stream in the Distributed Generation Working Group, as well as ongoing discussion of the topic in Phase 2 of the Proactive Distribution Upgrades docket (Docket No. 24-318) and in Xcel’s discussion of flexible interconnection in its 2025 Integrated Distribution Plan (Docket No 25-142). As those efforts explore tools such as static and dynamic export limits, operating envelopes, and other approaches to using existing hosting capacity more efficiently, we recommend that the Commission and Xcel consider whether incorporating specific elements of flexible interconnection into Capacity*Connect—particularly in Phase 2—could facilitate the integration of these storage facilities while reducing the need for traditional upgrades.

Xcel’s primary business case for these front-of-the-meter storage resources is to provide bulk system capacity, which comes with specific performance requirements during defined MISO capacity performance windows. In that context, we recommend that Xcel explicitly investigate the alignment and potential for co-optimization between flexible interconnection and that bulk capacity role, similar to how we and the Company have discussed co-optimizing these resources for distribution capacity value. In effect, seeing whether flexibly interconnected resources could, in principle, provide bulk capacity while also supporting distribution needs would be a valuable test case that Xcel should analyze in this proceeding—even if the Company ultimately chooses not to dispatch the resources in a way that would affect their MISO capacity accreditation.

g. Impact on other programs, such as distribution upgrade cost-sharing

We have no comment on this issue at this time but may comment further in reply and/or supplemental comments.

2. Does Xcel's filing fulfill Order Point No. 23 of the Commission's April 21, 2025 Order in Xcel's 2024 Integrated Resource Plan (Docket No. E002/RP-24-67)?

No, Xcel's filing does not fulfill Order Point No. 23 of the Commission's 2024 IRP Order because it offers assertions with no evidence. Among other things, that Order Point required the filing to include: "an evaluation of a costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer-owned and third-party-owned resources. Although Xcel's filing includes a section purporting to address this Order Point,[24] it does not offer a meaningful evaluation of benefits and costs of alternative ownership models. It presumes that only utility-owned assets can be "strategically site[d] and effectively integrate[d] … into the Company's grid planning and operations." However, the Company offers no explanation for why that is the case. Strategic siting, visibility, and control are not inherently related to ownership. Xcel can identify strategic sites or share the requisite data for third parties to site their assets in strategic locations. Likewise, third parties can agree to allow Xcel the visibility and control required to effectively integrate the assets into its planning and operations. Xcel does not engage with this possibility and its potential benefits in the Company's evaluation. Xcel also does not engage with the risk-reward tradeoff of utility versus third-party ownership, where ratepayers bear performance risk under utility ownership but would not with third-party ownership operating under performance-based contracts.

Regarding behind-the-meter assets specifically, Xcel properly recognizes that these DERs serve customer needs, in addition to potentially serving system needs through allowing the utility "partial control over their behind-the-meter DER." Contrary to Xcel's portrayal in its filing,

[24] Xcel Petition at 41-43.

however, realizing these two value streams is an additional opportunity, not a choice in opposition to Xcel's DCP framework. In other words, Xcel fails to recognize the opportunity to leverage both front-of-the-meter assets through Capacity*Connect and behind-the-meter resources through another DPP program offering. While we recognize that Xcel currently has other programs to incentivize behind-the-meter DERs, by adding the possibility of operational control similar to existing customer demand response programs, a DPP would allow it to maximize the benefits of these resources to all of its ratepayers, as well as leverage customer investment in DERMS systems and grid modernizing technologies. Xcel's filing fails to evaluate this opportunity in any meaningful way. As demonstrated in the attached Appendix, there are several successful utility DPP programs on which Xcel could model its own program in Minnesota, including one at its sister utility in Colorado.

Moreover, as described in Sections I and II, the Commission has gradually been moving in Xcel's IRP and IDP proceedings towards leveraging DERs as a distribution resource and encouraging customer engagement. By refusing to meaningfully consider alternative ownership models, as well as narrowing the focus of Capacity*Connect Phase 2 to bulk system value, Xcel has deviated from the Commission's path related to DERs. Furthermore, we emphasize the potential for third-party ownership—within Capacity*Connect (Recommendation 2 above) and through a separate BTM DPP program (Recommendation 3 above)—to advance equity in a meaningful way. Specifically, third-party ownership can promote customer- and community-wealth building and better reduce energy burden through direct bill savings opportunities.

Therefore, as discussed further elsewhere in these comments, we recommend the Commission require Xcel to explore alternative ownership models on two fronts: (1) establishing a timeline for introducing third-party participation into Capacity*Connect, permitting third-party ownership of front-of-the-meter DERs and requiring Xcel to offer information parity such that third parties can meaningfully participate; and (2) establishing a complementary behind-the-meter Distributed Power Plant program, permitting participation by customer- and third-party-owned DERs. We also recommend the Commission require Xcel to prioritize distribution value in Phase 2.

3. Should the Commission approve, modify, or deny Xcel's proposed implementation of a Grid DERMS use case to support Capacity*Connect?

In your response, please address at least the following topics:

a. Budget

In these initial comments, we do not take a position on the specific budget proposed for Xcel's Limited Grid DERMS proposal, but we may comment further in reply or supplemental comments.

b. Proposed use cases

Unless Commission makes the modifications described in our Recommendation 1 above to realize distribution value in Phase 2, we recommend the Commission reject Xcel's Limited Grid DERMS proposal. As discussed above, we believe the use case for Limited Grid DERMS in the context of Capacity*Connect involves using it to learn how to co-optimize bulk and distribution value, rather than solely for bulk-system dispatch as Xcel proposes. Specifically, to justify any Limited Grid DERMS investment, we recommend the Commission require Xcel to:

- Use the Limited Grid DERMS to dispatch Phase 2 resources in response to identified distribution constraints, not just MISO signals, when feasible;
- Document when and how DERMS dispatch decisions reflect tradeoffs between bulk and distribution needs; and

- Report on the degree to which concurrent benefit streams were actually realized, and what operational or institutional barriers were encountered.

4. Does Xcel's DERMS Roadmap in Attachment D of the proposal fulfill Order Point 23 of the Commission's September 16, 2024 Order in Xcel's 2023 Integrated Distribution Plan (Docket No. E002/M-23-452)?

Xcel has filed the same or a very similar DERMS Roadmap with its 2025 Integrated Distribution Plan (Docket No. E002/M-25-142). Consistent with Staff's request in the Notice of Comment Period in this proceeding, we reserve our comments on the Roadmap and broader DERMS implementation (beyond the Limited Grid DERMS proposed here) for the 2025 IDP proceeding. We understand the Commission's Order Point 23 in the 2023 IDP Order to envision this more comprehensive review of the Company's DERMS plans, including use cases beyond its application in the DCP, like flexible interconnection and energization.

Therefore, we believe that Xcel Energy has fulfilled Order Point 23 only in part. It has satisfied the requirement that it "file a detailed roadmap for DERMS deployment that addresses the questions provided below," however review in the 2025 IDP proceeding will determine whether it has "adequately addressed these questions." While the Commission may opt to approve Xcel's budget and plans for its Limited Grid DERMS deployment in this proceeding, we suggest that the Commission not approve any cost recovery for this or any other DERMS investments until it determines that Xcel's Roadmap is adequate. Please see our response to Question 3 above regarding our comments and recommendations related to Xcel's Limited Grid DERMS proposal. Please see our response to Question 5 below for further discussion of cost recovery for Capacity*Connect and Limited Grid DERMS.

5. Should the Commission approve, modify, or deny Xcel's request to seek cost recovery of Capacity*Connect and Grid DERMS costs through its Renewable Energy Standard (RES) Rider?

The Commission should deny Xcel's request to seek cost recovery through its RES Rider. The foundational purpose of the RES Rider is to recover costs associated with compliance with the state Renewable Energy Standard, Minn. Stat. § 216B.1691. Specifically, Minn. Stat. § 216B.1645, Subd. 2a(a) states: "A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691,…" Within that same statutory provision, Subd. 2a(a)(3) "…allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage,…" provided that the utility meets certain requirements. In the first place, as proposed, Phase 2 only contemplates stand-alone energy storage, not storage "directly related to a renewable energy project." Therefore, as proposed, Capacity*Connect does not satisfy that statutory requirement.

More broadly, while Capacity*Connect may be "designed to support a carbon-free system," as Xcel states in its Petition,[25] its primary goal is not to satisfy the Renewable Energy Standard requirements in Section 216B.1691. Rather, Xcel describes the program as "…an innovative way to use BESS to provide grid value and meet our customers' needs by strategically and functionally deploying storage assets on the Company's distribution system."[26] Xcel goes on to call Capacity*Connect "…a step-change in how Xcel Energy and other utilities are beginning to incorporate distributed energy resources into system planning and operations," and states that program assets "could be used to offset peak load, mitigate curtailment of

[25] Xcel Petition at 50.
[26] Xcel Petition at 4.

renewables and support more renewables on the system, meet bulk system capacity needs and participate in Midcontinent Independent System Operator (MISO) markets, and more."[27] These goals, while commendable, are more expansive than RES compliance and the cost recovery contemplated by Section 216B.1645 for the RES Rider.

Notably, Xcel appears to rely on its RES Rider mostly to recover solar and wind project costs, along with costs associated with the Sherco battery project co-located with the Sherco solar projects. In Docket No. E-002/M-24-353 regarding Xcel Energy's Petition for Approval of its 2025 Renewable Energy Standard Rider Revenue Requirements, the Department of Commerce provided the following summary table in its recommendations: [28]

Table 1: Xcel's Proposed RES Rider Revenue Requirements and Tracker Summary[7]

Line	Item	2023 Actual	2024 Mixed	2025 Forecast
1	Projects moved to base rates beg. 2024*	59,946,214	-	-
2	Northern Wind	9,181,657	6,960,250	7,633,561
3	Nobles Wind Re-Power	2,573,639	502,694	714,611
4	Grand Meadow Wind Re-Power	3,345,998	1,976,737	1,886,127
5	Borders Wind Re-Power	295,871	684,472	6,798,763
6	Pleasant Valley Wind Re-Power	450,719	958,416	8,453,072
7	Sherco Solar 1&2	7,466,225	32,172,914	37,254,555
8	Sherco Solar 3	261,528	2,212,489	13,986,477
9	Sherco Battery	7,219	153,118	1,369,266
10 (sum 1:9)	**Project Subtotal**	**83,529,070**	**45,621,090**	**78,096,432**
11	PTC True-Up for Base-Rate Projects	(514,040)	(30,134,627)	-
12	Rate Case Adj. Reversal (Interim Period)	1,288,000	-	-
13 (sum 10:12)	**Gross Revenue Requirement**	**84,303,030**	**15,486,463**	**78,096,432**
14	Carryover (Prior Year-End Balance)	45,753,015	(3,260,043)	(13,496,504)
15 (sum 13:14)	**Net Revenue Requirement**	**130,056,045**	**12,226,420**	**64,599,928**
16	Revenue Collections	133,316,088	25,722,924	64,608,750
17 (15 less 16)	**Year-End Balance**	**(3,260,043)**	**(13,496,504)**	**(8,822)**

*The projects moved to base rates beginning in 2024 are the following wind projects: Blazing Star I; Blazing Star II, Courtenay Wind, Crowned Ridge, Foxtail, Freeborn, Lake Benton, Dakota Range, Jeffers WF, Community Wind North, Mower

[27] Xcel Petition at 4.

[28] Docket No. E-002/M-24-353, *In the Matter of Xcel Energy's Petition for Approval of its 2025 Renewable Energy Standard Rider Revenue Requirements*, Order (May 27, 2025) (Department's recommendations attached and incorporated, table on page 6 of those recommendations), *available at* https://efiling.web.commerce.state.mn.us/documents/%7BC0CD1297-0000-C61C-99E0-ECA74E3205A1%7D/download?contentSequence=0&rowIndex=3.

As this table shows, allowing for cost recovery through the RES Rider for Capacity*Connect and Limited Grid DERMS would be out of step with how the RES Rider is currently used.

For these reasons, we recommend that the Commission deny Xcel's request to recover costs for Capacity*Connect Phase 2 and Limited Grid DERMS through the RES Rider. Instead, we recommend that the Commission direct the Company to pursue cost recovery through a general rate case, subject to traditional prudency review. In addition, as indicated above, the Commission's Order Point 23 in its 2023 IDP Order requires Xcel to demonstrate, prior to cost recovery for DERMS investments, that it has adequately answered the Commission's questions in its DERMS Roadmap, which is currently pending in its 2025 IDP proceeding. Therefore, with respect to Limited Grid DERMS, we recommend that the Commission postpone any grant of cost recovery—through the RES Rider or otherwise—until it has reviewed Xcel's DERMS Roadmap and found it adequate.

6. Are there other issues or concerns related to this matter?

We have no additional issues or concerns at this time but may respond further in reply or supplemental comments.

IV. CONCLUSION

We continue to strongly support the Commission's and Xcel's movement towards relying on DERs as a system resource for the full suite of services they can provide. The modifications we recommend restore Xcel's proposal to alignment with the Company's initial vision for this program, as expressed in its August 2024 IRP comments and articulated at a high-level in its Petition in this docket—unlocking the full potential of DERs to drive reliability, resilience, and cost-effective outcomes. In sum, we recommend that the Commission:

- Modify Xcel's Capacity*Connect Phase 2 proposal prior to approval.

- Require Xcel to take concrete steps to advance distribution value in Capacity*Connect Phase 2 by July 1, 2027, as discussed within our Recommendation 1 above.
- Establish a timeline and requirements for third-party participation in the Capacity*Connect, such that Xcel begins to solicit third-party-owned front-of-the-meter assets by July 1, 2027, as discussed within our Recommendation 2 above.
- Require Xcel to work with stakeholders to develop and file a complementary behind-the-meter Distributed Power Plant (DPP) program by July 1, 2026, as discussed within our Recommendation 3 above.

Respectfully submitted,

/s/ Erica S. McConnell

Erica S. McConnell
Staff Attorney
Bradley D. Klein
Managing Attorney
Environmental Law & Policy Center
35 E. Wacker Drive, Suite 1600
Chicago, IL 60601
(312) 673-6500
emcconnell@elpc.org
bklein@elpc.org

/s/ William D. Kenworthy

William D. Kenworthy
Senior Regulatory Director, Midwest
Vote Solar
1 South Dearborn Street, Suite 2000
Chicago, IL 60603
will@votesolar.org

/s/ Pouya Najmaie

Pouya Najmaie
Policy and Regulatory Director
Cooperative Energy Futures
310 E 38th St Suite 109
Minneapolis, MN 55409
(612) 715-1224
pouya@cooperativeenergyfutures.com

/s/ John Farrell

John Farrell
Director, Energy Democracy Initiative
Institute for Local Self-Reliance
2720 E. 22nd St
Minneapolis, MN 55406
jfarrell@ilsr.org

/s/ Shannon Anderson

Shannon Anderson
Distributed Power Plant Policy Director
Solar United Neighbors (SUN)
1350 Connecticut Ave., NW, Suite 412
Washington, DC 20036
sanderson@solarunitedneighbors.org

Date: December 10, 2025

Appendix - Distributed (Virtual) Power Plant Program Examples

The examples below show a behind-the-meter (BTM) program that harnesses the collective power of customer distributed energy resources (DERs) adds significant value and capacity. Distributed Power Plants (DPPs), also known as Virtual Power Plants (VPPs), are the fastest growing source of on-demand dispatchable capacity for utilities across the country.

These programs often start with coordination of residential customer resources (home batteries and smart devices), but they can be built out to include commercial and industrial customer resources as well and to incorporate load flexing or demand response for larger customers to operate in concert with other programs.

Distributed Power Plants leverage private-sector investment and innovation allowing clean energy resources to scale quickly and cost-effectively. As evidence of this, Uplight (a company that helps connect customer resources to utilities) recently disclosed they helped to shift 4.4 GW of load across 25 utilities just this summer, amounting to a 32% year-over-year increase in dispatchable clean energy capacity. EnergyHub coordinates resources across 80+ utilities and estimates an additional 10 times of impact with 44 GWs of load shifting in 2024, equivalent to the annual production of about five fossil peaker plants. CPower, which coordinates 38 GWhs of resources at the commercial and industrial customer level announced in November that its programs have increased by 137% from last year. Overall, Ohm Analytics recently found that Distributed Power Plant programs increased 229% year-over-year.

Wood Mackenzie estimates that 35% of all home solar installations this year will include batteries. These battery installations represent hundreds of megawatts of already-deployed clean energy resources, just waiting for the right Distributed Power Plant policy to be put in place to maximize impact for the grid. Xcel in Minnesota should join a growing list of utilities across the country, including the utility's sister utility in Colorado, that are deploying Distributed Power Plant programs to the benefit of all ratepayers.

Arizona

The Arizona Corporation Commission approved Arizona Public Service Co.'s (APS) Storage Rewards program in March 2025. The program compensates customers for providing battery storage to help the utility meet peak demand needs during hot summer months. Customers participating in the Storage Rewards Program will be compensated with an annual $110 per available Kilowatt. It is based on the seasonal average capacity of energy exported to the electric grid from their battery system. The utility would typically only use the additional generation when market rates would otherwise be much higher than the $110/kW rate. In other words, the program saves money for all customers.

California

The California Energy Commission (CEC) Demand Side Grid Support (DSGS) Program is part of California's Strategic Reliability Reserve. It is a suite of programs to alleviate limited energy supplies on the grid caused by heatwaves and wildfires. DSGS offers incentives to electric customers that can help balance energy demands and backup generation to support the state's electrical grid during extreme events from May to October. This lowers the risk of rotating power outages. The DSGS Program is open to eligible DSGS providers and participants. It has four incentive structure options to choose from. The battery storage option in the program scaled from 369 MW in 2024 to 1154 MW in 2025, representing significant growth.

Colorado

The Colorado PUC recently approved a precedent-setting settlement agreement between Xcel Energy and a variety of solar industry, local government, and nonprofits in Docket No. 24A-0547E. The program enables 125 MW of residential battery storage to be connected to the grid over a five-year period.

Massachusetts

National Grid's Connected Solutions Program, which operates in Massachusetts and other New England states, compensates customers for allowing their home batteries to contribute stored energy to the grid during times of peak demand, helping to lower overall grid strain while also providing financial incentives to participants. Participants average around $1,500 in annual incentives for connecting their home batteries to the system. The program has almost 500 MW of customer resources available, and it includes both residential and commercial customers.

Puerto Rico

LUMA's Customer Battery Energy Sharing (CBES) program compensates customers for the energy they provide to reduce peak demand needs of the utility. The utility offers compensation of $1.25/kWh. A portion of this is shared with the third-party aggregator company that handles enrollment and payment for customers. The program is a remarkable success story in the ability to rapidly scale, with growth from 38 MW in 2024 to 500 MW in 2025. The program now includes over 80,000 customers, making it one of the largest DPP programs in the country.

Utah

Rocky Mountain Power's WattSmart Battery Program offers incentives to homeowners who install batteries paired with solar power, allowing the utility to draw stored energy to support the grid during peak demand. Participants receive upfront payments and annual bill credits based on their battery's power output. The program easily passes all of the cost tests as part of a review by the Commission through the utility's demand side management annual program filing.

☐ **Not-Public Document – Not For Public Disclosure**
☐ **Public Document – Not-Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No.	5
Docket No.:	E002/M-25-378		
Response To:	Minnesota Public Utilities Commission		
Requestor:	Isabel Ricker		
Date Received:	10/21/25		

Question:
On page 18 of Xcel's Petition in this docket, Xcel states: "Minnesota's DER policies as they currently stand – including the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) – do not necessarily contemplate the C*C concept: FTM, utility-owned and -controlled, dispatchable DER, strategically deployed to serve as bulk system assets that are not functionally different from the Company's distribution system. So, while we will perform necessary studies to assess impact of the C*C BESS on the system, C*C assets akin to bulk system resources are not subject to MN DIP."

Please explain in more detail:

a. How are Phase 2 C*C resources both akin to bulk system resources and not functionally different from the Company's distribution system?
b. Why does Xcel believe Phase 2 C*C resources are not subject to MNDIP?
c. Will the Company count C*C projects towards feeder loading standards for either generation or load?

Response:

a. Phase 2 Capacity*Connect (C*C) resources are akin to bulk system resources because the Company intends to operate these resources in a way that would qualify for energy and capacity value in the Midcontinent Independent System Operator (MSIO) wholesale market. This is a high-bar that not all distributed energy resources (DERs) that are distribution-connected meet.

   At the same time, these resources are functionally part of the Company's distribution system because they are planned, interconnected, and operated entirely within the Company's distribution network using utility tools and procedures. They are deployed, monitored, and maintained like other controllable grid assets – such as automated switches, capacitor banks, and reclosers – and will be managed through the Company's Grid Distributed Energy Resource Management System (Grid DERMS).

By embedding C*C assets into the same planning, operational, and asset-management framework**s** that govern other distribution equipment, the Company ensures that these batteries operate as integral components of the distribution system while simultaneously providing capacity value that supports bulk system reliability.

b. The Minnesota Distributed Energy Resource Interconnection Process (MN DIP) was designed to govern the connection of non-utility DERs – typically customer or third-party owned – to the utility's distribution system. The Company does not believe MN DIP applies to the Distributed Capacity Procurement (DCP) assets proposed under the C*C program, because these front-of-the-meter battery energy storage systems (BESS) are utility-owned, utility-operated components of the Area Electric Power System (Area EPS) rather than separate electric systems seeking to interconnect.

   Under IEEE 1547-2018, which Minnesota has incorporated by reference through MN DIP and the associated Technical Interconnection and Interoperability Requirements (TIIR), "interconnection" is defined as the coupling of two distinct electric power systems: a Local Electric Power System (Local EPS), typically a customer facility, and the Area EPS, operated by the utility. The *Point of Common Coupling* (PCC) is the boundary where those systems meet and where the interconnection requirements of IEEE 1547 apply. Because the proposed DCP BESS will be wholly contained within, and operated as part of, the Area EPS, there is no PCC in the IEEE 1547 sense. Consequently, the activities associated with adding these assets – site design, protection coordination, communications integration, and energization – do not constitute *interconnections* between separate systems. They are planned system connections on the Company's side of the meter.

   Minn. Stat. 216B.1611, *Interconnection of On-Site Distributed Generation*, further supports this distinction. The statute repeatedly refers to "on-site" distributed generation, a term that in ordinary usage – and by the context of the statute – refers to customer-sited resources located on the customer's premises. The MN DIP and related MN DIA (agreement) and TIIR (technical) documents collectively implement this statute by defining a process, contract, and technical standards that govern interactions between the utility and a non-utility interconnection customer. Those provisions ensure safe and nondiscriminatory access to the distribution system for external DER developers. In the case of utility-owned DCP assets, there is no separate customer and therefore no contractual or jurisdictional interface for MN DIP to govern.

   Although MN DIP does not apply, the Company recognizes the importance of maintaining the same level of technical rigor and safety. All C*C BESS sites will undergo comprehensive engineering reviews within the Company's existing distribution planning, protection, and operational processes. These reviews evaluate thermal loading, voltage impacts, fault-duty contributions, protection coordination, and communication requirements, and will be complemented by the controls and cybersecurity evaluations associated with the Company's Grid DERMS implementation. This approach ensures equal or greater technical scrutiny compared to the MN DIP process while avoiding unnecessary administrative duplication.

Exempting C*C BESS from MN DIP preserves the integrity of the State's interconnection framework for customer and third-party DERs and prevents procedural duplication. The Company's approach maintains that same distinction: C*C batteries are utility system assets, planned and operated within the distribution system, and do not constitute interconnections under either the statutory or technical definitions adopted in Minnesota.

c. Yes, the C*C projects contribute to load and generation capacity on the system. However, these resources will be planned and operated as controllable utility assets that must remain within existing thermal and voltage limits established by the Company's feeder loading standards.

Asset thermal limits – often expressed as current-based loading limits derived from conductor and equipment ratings – will continue to govern system planning and operational loading practices. The Company will account for these limits whenever C*C resources charge or discharge. Because the batteries are owned, operated, and centrally managed by the Company, their operation can be scheduled and constrained through the Grid DERMS to ensure compliance with all loading criteria.

In summary, C*C resources will function as actively managed components of the distribution system designed to operate within – and sometimes alleviate – existing constraints.

Preparer:	James Denniston	Zachary Pollock
Title:	Assistant General Counsel	Director
Department:	Legal Services	Grid Strategy & Emerging Technologies
Telephone:	(612) 215-4656	(914) 584-6470
Date:	October 31, 2025	October 31, 2025