



414 Nicollet Mall  
Minneapolis, MN 55401

March 19, 2026

—Via Electronic Filing—

Sasha Bergman  
Executive Secretary  
Minnesota Public Utilities Commission  
121 7<sup>th</sup> Place East, Suite 350  
St. Paul, MN 55101

RE: REPLY COMMENTS- IDP  
2025 INTEGRATED DISTRIBUTION PLAN  
DOCKET NO. E002/M-25-142

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments, along with Attachment A, in response to the November 13, 2025 Notice of Comment Period in the above-referenced docket. These Reply Comments and Attachment A address stakeholder feedback on the Company's 2025 Integrated Distribution Plan.<sup>1</sup>

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Taige Tople at [taige.d.tople@xcelenergy.com](mailto:taige.d.tople@xcelenergy.com) or me at [brian.t.monson@xcelenergy.com](mailto:brian.t.monson@xcelenergy.com) if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON  
MANAGER, REGULATORY AFFAIRS

Enclosures  
cc: Service List

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<sup>1</sup> We are filing separate Reply Comments on our mobile battery certification request.

STATE OF MINNESOTA  
BEFORE THE  
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF XCEL ENERGY'S 2025  
INTEGRATED DISTRIBUTION PLAN

DOCKET NO. E002/25-142

**REPLY COMMENTS**

**INTRODUCTION**

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments to the Minnesota Public Utilities Commission in response to Initial Comments filed on February 26 and 27, 2026 by the City of Minneapolis, Fresh Energy, Environmental Law & Policy Center, Vote Solar, and Cooperative Energy Futures (collectively, ELPC/VS/CEF), and the Minnesota Department of Commerce, pursuant to the Commission's November 13, 2025 Notice of Comment Period. These Reply Comments address stakeholder feedback on the Company's 2025 Integrated Distribution Plan.<sup>1</sup>

At the outset, the Company notes that we are proud of the progress reflected in our 2025 IDP and of how far our distribution planning practices have advanced with each successive filing. Through iterative IDPs that incorporate refined information and ongoing improvements to our planning tools and methodologies, we have taken meaningful, proactive steps to modernize the distribution system, enhance transparency, and better position our grid to meet evolving customer needs. This IDP builds on a solid foundation by incorporating lessons learned, advancing our planning practices, and identifying targeted investments to support safety, reliability, and affordability over the long term.

The IDP framework has enabled productive dialogue on a wide range of issues, and many stakeholders appropriately focused their comments on discrete topics that can enhance the informational value of future IDPs. However, as discussed in these Reply Comments, we received more than 70 recommendations and requests for additional

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<sup>1</sup> We are filing separate Reply Comments on our mobile battery certification request.

analysis or reporting—spanning numerous subject areas and levels of detail—that in many cases go well beyond the scope of the IDP as established by the Commission.

While the Company appreciates the effort expended, the sheer number and scope of recommendations make it difficult to discern where stakeholders want the Company to prioritize its focus. The Company is concerned that an approach to planning emphasizing volume over prioritization risks diverting attention from the most material planning issues and constraining the Company’s ability to advance timely, actionable, and necessary grid investments to ensure reliable and resilient service to customers.

Accordingly, these Reply Comments respond thoughtfully to stakeholder feedback while reaffirming the IDP’s purpose as an informational report. The Company remains committed to proactive planning, transparency, and continued advancement of its distribution planning practices. At the same time, the Company welcomes a focused dialogue. That dialogue should recognize both the progress already made as well as the Company’s need to apply engineering and operational expertise and judgement to fulfill its obligation—and privilege—to provide reliable and safe electrical service to customers. It should also acknowledge the practical limits on how many new requirements can be effectively addressed within system planning or within a single IDP cycle.

In these Reply Comments, the Company highlights several areas of particular concern, including:

- **Planning process–related recommendations**, including proposals that would unreasonably expand involvement in core engineering standards, forecasting methodologies, and system planning criteria;
- **Cost-benefit analysis (CBA) recommendations**, particularly those calling for broad or mandatory CBAs across multiple programs and investment categories that may not be methodologically appropriate or practicable within a system planning construct or the IDP framework; and
- **Retrospective forecast and project reporting recommendations**, including requests for expanded backward-looking comparisons that would be resource-intensive, duplicative of existing analysis, and of limited value to forward-looking planning.

Attachment A to this Reply provides comprehensive responses to each proposed recommendation and request for additional information. The Company offers these responses to help ensure the IDP advances the Commission’s objectives for distribution planning in a manner that is forward-looking, focused on the right

priorities and outcomes for customers, and practicable to implement.

## **I. PLANNING PROCESS-RELATED RECOMMENDATIONS**

Stakeholders submitted a substantial number of recommendations related to the Company's distribution planning processes, forecasting methodologies, and planning standards. While the Company appreciates stakeholder engagement and values ongoing dialogue, many of these recommendations raise concerns regarding scope, feasibility, and the appropriate balance between regulatory oversight and technical system planning. These concerns underlie the Company's opposition to most planning-process-related recommendations discussed below.

As a foundational matter, the Company's planning standards are engineering-based criteria developed to ensure the safe, reliable, and cost-effective operation of the distribution system under a wide range of operating conditions. These standards govern how the Company forecasts load, evaluates system risk, sizes assets, and prioritizes investments to meet its obligation to serve customers. They are not policy preferences or discretionary guidelines, but technical standards grounded in engineering science and judgment, operational experience, and equipment capabilities – informed by a deep understanding of distribution system conditions and performance. The IDP is an informational filing that describes how these standards are applied to identify system needs and anticipated investments to meet our customers' requirements; it has not to-date been intended to redefine or re-adjudicate the planning standards themselves.

Several stakeholder recommendations—particularly those calling for Commission- or stakeholder-directed review, modification, or approval of core planning standards—would materially alter this framework. The Company is concerned that such approaches would undermine the consistent application of engineering science, expertise, and judgment. They would also introduce new areas of uncertainty into system planning—particularly uncertainty about whether current system design philosophies and standards would remain in effect long enough to ensure that newly built infrastructure remains viable under future planning criteria. Finally, these approaches could delay investments needed to maintain safety and reliability. Detailed reviews of capacity planning standards, N-0 and N-1 risk analysis methodologies, asset sizing practices, and prioritization criteria would also require substantial resources across multiple technical teams, with uncertain benefit to the IDP process and system planning practices – and potentially divert from forward-looking planning work.

Stakeholders also requested extensive additional forecasting detail and retrospective

reconciliation, including adoption-rate breakouts by Planning Division, expanded sensitivity analyses, and reconciliation of forecast values to historical peak load patterns. Many of these requests misunderstand how forecasts are developed and applied.

Planning Divisions are administrative constructs to manage work—not forecasting units. Forecasts are developed at the state and system levels and allocated to feeders and substations based on engineering analysis. Moreover, year-to-year peak variability reflects expected influences such as weather, customer energization timing, economic conditions, and data transitions. The current process has checks and balances to ensure reasonable forecasting certainty before initiating infrastructure investments. Requiring retroactive reconciliation to incomplete or non-comparable historical data would not meaningfully improve forecast accuracy and risks drawing misleading conclusions.

With respect to Planned Net Loading (PNL), stakeholder comments focused on the photovoltaic dependability factor. The Company’s current approach is consistent with Commission direction, grounded in multi-year empirical data, and intentionally conservative to ensure reliability. While the Company supports continued refinement and has developed a seasonal framework for implementation in the 2027 IDP, it does not support interim filings or accelerated implementation outside the established planning cycle, which would create duplicative and inefficient reporting obligations.

Finally, several recommendations proposed establishing recurring or ad hoc processes through which stakeholders could initiate reviews of planning standards or require quantitative cost-benefit analyses of alternative standards. The Company’s central concern is that such processes would blur the line between regulatory oversight and technical system design, expand the scope of the IDP beyond its intended purpose, and introduce uncertainty that could delay necessary investments to meet our customers’ needs. The Company has an obligation—and privilege—to provide safe and reliable service to customers under the regulatory compact, and as such, maintains its subject-matter expertise to plan and operate its system. While the Company supports transparently communicating changes to planning standards in future IDPs, it does not support shifting responsibility for defining those standards away from the utility.

In responding to these recommendations, the Company supports an IDP that is forward-looking, technically grounded, and practicable to implement—all in a manner that enables the Company to meet our obligation, and privilege, to provide safe and reliable service to our customers. While the Company remains committed to proactive planning, transparency, and continued improvement, we also emphasize the need to

preserve the engineering judgment and science, flexibility, and resources required to plan and operate the distribution system safely and reliably.

## II. CBA RECOMMENDATIONS

Stakeholders submitted numerous recommendations to expand the use of CBAs across a wide range of distribution planning activities, including grid reinforcement, asset health & reliability (AH&R) programs, wildfire mitigation, targeted undergrounding, DERMS use cases, and large distribution projects. While the Company supports CBAs as one decision-support tool, it has significant concerns regarding the scope, timing, and mandatory nature of many of these recommendations.

CBAs are one of several tools used to inform investment decisions and are most effective when applied in a targeted, methodologically sound manner where data quality and modeling maturity support reliable results. They are not, however, the sole determinant of investment decisions, and they are not a one-size-fits-all approach to every circumstance. Engineering standards and judgment, risk-based planning, and the Company's obligation to provide safe and reliable service are paramount. In many circumstances—particularly where safety, reliability, or service obligations are triggered—the Company must proceed with investments regardless of whether a favorable economic outcome can be demonstrated through a CBA.

The Company's primary concern is the sheer number and breadth of new CBA recommendations suggested in this proceeding—fourteen in total. Collectively, these recommendations would require CBAs across nearly all planning areas, including programs that involve mandatory safety work, long-term reliability benefits, or emerging technologies where valuation methods are still evolving. The IDP is an informational planning filing and layering comprehensive CBAs onto every planning activity risks diverting limited analytical and engineering resources away from forward-looking system planning for our customers.

Several recommendations propose blanket CBA mandates for entire portfolios, including AH&R programs and DERMS use cases. The Company is concerned these approaches do not sufficiently account for the mandatory nature of much reliability work or the limitations of current modeling tools. For example, AH&R programs often involve inspection-driven replacements that must proceed regardless of CBA outcomes. And DERMS use cases are still being defined and validated through limited deployments, making comprehensive CBAs premature.

Stakeholders also recommended forward-looking system-wide CBAs and expanded

retrospective reporting, including ten-year CBA updates and detailed project-level analyses for large distribution investments. The Company is concerned these requirements conflate planning with ratemaking and would impose prescriptive analytical obligations long after programs may have evolved or concluded, reducing flexibility and offering limited incremental value to customers and the Commission.

The Company can support measured use of CBAs where they are clearly useful to inform decisions. This may include discretionary programs with clear, quantifiable benefit streams and stable data inputs. We can also support methodological improvements such as appropriate discounting and greater transparency around assumptions. These efforts are best advanced incrementally across IDP cycles and addressed in appropriate regulatory venues, while ensuring that critical and time-sensitive reliability and capacity expansion investments are not delayed by overly broad analytical mandates.

### **III. RETROSPECTIVE FORECAST AND PROJECT REPORTING**

Stakeholders recommend expanding retrospective reporting in the IDP, including comparisons of forecasted and actual peak loads and project-level comparisons of forecasted versus actual outcomes for large distribution investments. While the Company supports transparency and continuous improvement, it does not support establishing new retrospective reporting mandates within the IDP framework.

Forecast accuracy analysis was addressed in the 2025 IDP and compares prior forecasts to observed peak loads. Differences between forecasts and actuals are expected due to weather variability, customer behavior, timing of load additions, and system operations. Importantly, the IDP forecast is a planning forecast designed to capture plausible upper-bound system stress—not to predict the most likely outcome in any single year. Requiring additional retrospective comparisons would duplicate existing analysis, rely on incomplete historical datasets, and require significant additional analytical effort without materially improving forward-looking planning.

Similarly, the proposal to require retrospective project outcome reporting for large distribution investments would be highly resource- and time-intensive while lacking clarity regarding what “outcomes” would be measured or how comparisons would be applied across projects with differing objectives, timelines, and drivers. Developing consistent, meaningful retrospective comparisons would require substantial staff time to reconstruct assumptions, normalize changing system conditions, and reconcile evolving project scopes—diverting limited planning resources away from their focus on current and future system needs.

More fundamentally, forecasts and project plans are not static. They are dynamic and continuously updated as new data becomes available, customers' needs and timelines change, and operating conditions change. Projected investments are routinely reassessed before final construction decisions are made or initiated. This iterative review process provides a practical safeguard against overbuilding while allowing the Company to adapt plans efficiently as conditions change.

For these reasons, the Company does not support new retrospective reporting requirements in the IDP that would duplicate existing analysis, impose significant additional resource burdens, blur the distinction between planning and prudence review, detract from forward-looking system planning, and have no practical benefit to customers.

### **CONCLUSION**

The Company appreciates the opportunity to provide these Reply Comments and supports the Commission's goal of a forward-looking and transparent approach to distribution planning. The Company has made substantial progress in advancing its planning practices and its IDP – and remains committed to continued improvement. However, many of the recommendations in this proceeding would significantly expand the scope of the IDP and impose prescriptive requirements that are inconsistent with an informational filing without delivering clear value to our customers.

The Company urges the Commission to balance innovation with engineering-based decision-making and practical implementation considerations, and to preserve the IDP as a focused, forward-looking report that provides transparency into how the Company plans for and delivers safe and reliable electric service to customers, including its planning practices and future investments.

Dated: March 19, 2026

Northern States Power Company

This attachment discusses every proposed recommendation from stakeholders. We organize our responses into the following eleven subject areas:

- I. Planning Process Related Recommendations
- II. Cost Benefit Analysis
- III. Asset Health and Reliability Planning
- IV. Flexible Interconnection
- V. FERC Order 2222
- VI. Wildfire Mitigation
- VII. Targeted Undergrounding
- VIII. Grid Modernization
- IX. Non-Wires Alternatives
- X. Review of IDP Filing Requirements
- XI. Recommendations Outside the Scope of the IDP

## **I. PLANNING PROCESS RELATED RECOMMENDATIONS**

The Company's planning standards are engineering-based criteria used to ensure the safe, reliable, and cost-effective operation of the distribution system. These standards govern how the Company forecasts load, evaluates system risks, sizes assets, and prioritizes investments to meet its obligation to serve customers under a wide range of operating conditions. They are not policy preferences, aspirational targets, or discretionary guidelines. They are developed and applied through the Company's carefully refined and highly technical engineering processes.

The IDP is an informational planning filing that describes how the Company applies its planning standards to identify system needs and anticipated investments. It is not intended to redefine technical engineering criteria or shift responsibility for those criteria away from the utility. Several recommendations discussed in this section would move toward greater Commission or stakeholder-directed review of foundational engineering planning standards. The Company is concerned that such an approach could undermine the application of engineering judgment, introduce delays in addressing system needs, and blur the distinction between regulatory oversight and technical system design.

Against that backdrop, the Company responds to the following planning-process comments and recommendations.

## A. Electrification and Peak Load Growth

CEE notes that residential space heating electrification could materially increase winter peak demand, citing LoadSEER results showing cumulative impacts ranging from 274 MW (base) to 1,625 MW (high) by 2036. The Company agrees that electrification is an important driver of future peak load and acknowledges that winter peaks are expected to grow over time. These dynamics are reflected in the Company's forecasting framework and scenario development, which incorporate electrification trends and associated uncertainty as part of forward-looking system planning.

## B. Use of Planning Divisions in Forecasting

The Department asks why Planning Divisions appear to extend beyond the Company's Minnesota service territory, whether any non-jurisdictional data influences Minnesota forecasts, and how Minnesota regulatory decisions are insulated from out-of-state conditions. The Company addresses these questions by clarifying what Planning Divisions are—and are not—and how they are used in the IDP.

**What Planning Divisions are—and are not.** Planning Divisions are internal geospatial groupings created to organize noncontiguous areas of the service territory for planning efficiency. They generally align with service center territories (with some overlap where assets cross boundaries) and use location codes to track certain categories of distribution spending. These constructs are administrative, not jurisdictional.

Planning Divisions are not forecasting units. Distribution planning and LoadSEER forecasting are performed at the feeder-circuit and substation-transformer levels based on system-wide forecasts developed at the state level; Planning Divisions serve only as an intermediate aggregation layer for internal management and reporting. Consequently, Minnesota peak load forecasts, asset needs, and project prioritization are driven by feeder/substation conditions within Minnesota—not by the broader geography of a Planning Division polygon.

**IDP uses Minnesota only inputs and decisions.** Forecasting and planning activities in the IDP apply only to assets and customers within the Company's service territory in Minnesota. Where a Planning Division polygon encompasses areas served operationally from North Dakota or South Dakota service centers, or areas outside the Company's service territory, Minnesota IDP inputs and outputs still only include the Company's Minnesota assets and customers. No load, asset, or spending data

from outside the Company's Minnesota service territory is embedded in Minnesota Planning Division forecasts; accordingly, Minnesota regulatory decisions are not influenced by out of state or other non-jurisdictional conditions.

### **C. Reconciling Forecasts with Historical Patterns**

The Department requests that the Company reconcile highlighted forecast values in Table 5 in its Initial Comments with historical peak load trends. The Company does not support this request.

Year-to-year peaks naturally fluctuate due to factors such as weather variability, changes in customer energization timing, general economic activity (e.g. the COVID-19 induced recession of 2020), differences between expected and actual large customer demand, and distributed solar generation. These variations are expected and do not indicate deficiencies in the forecasting methodology.

Moreover, the historical values in Table 5 are not a reliable basis for comparison. Data for 2020–2021 is incomplete due to the Company's transition to LoadSEER. Attempting to reconcile forecasts to incomplete or non-comparable data is methodologically unsound and risks drawing inaccurate conclusions about forecast performance.

The IDP forecast is also a *forward looking planning tool*, designed to incorporate updated Advanced Metering Infrastructure (AMI)/Supervisory Control and Data Acquisition (SCADA) inputs and evolving load trends—not to match any single historical year's peak. We already evaluated forecast performance in the 2025 IDP (Table 1-11), with appropriate context for observed differences. An additional reconciliation based on incomplete data would duplicate this work without adding value. Accordingly, the Company does not support the Department's request.

### **D. Drivers of Projected Peak-Load Growth**

The Department asks for additional detail on EV and electrification adoption rates by Planning Division, empirical data sources, subsidy assumptions, sensitivities, and incorporation of load diversity and demand management.

The Company does not support these requests for the following reasons:

- 1. Planning Divisions Are Not Forecast Units.** Planning Divisions serve only as administrative boundaries aligned with service center territories; they are not used to develop or allocate adoption forecasts. LoadSEER develops adoption forecasts at the system and state levels, then allocates them spatially to specific locations on the distribution system. Information on adoption rates and other assumptions embedded in these forecasts is provided in Chapter 1 of our 2025 IDP.
- 2. Adoption Rate Breakouts Do Not Exist at the Planning Division Level.** We do not maintain EV or electrification adoption rates by Planning Division. LoadSEER's layers—EVs, beneficial electrification, solar PV, battery storage, and energy efficiency—represent forecast categories, not demographic or geographic trend assignments. Forecasted adoption rates for these layers are identified at the state level and provided as an input to LoadSEER.
- 3. Scenario Development is Highly Manual and Resource-Intensive.** Creating alternative adoption scenarios requires rebuilding each LoadSEER scenario from scratch. LoadSEER is a dynamic model, regularly updated with new AMI, SCADA, and customer load data—meaning the June forecast does not reflect the same inputs the Department proposes to use for sensitivity analysis. Running additional scenarios for Reply Comments would therefore require significant resources from both the Company's planning staff and the LoadSEER vendor (Integral Analytics), while relying on outdated data and without providing meaningful value.
- 4. Demand Side Impacts Already Reflected.** Demand response and energy efficiency effects are inherently captured in our AMI and SCADA data, and we separately forecast Demand Response and Energy Efficiency impacts in future years. These considerations are already integrated into peak load estimates.

## **E. Review of Capacity Planning Standards**

The Department recommends that the Commission require a comprehensive review of the Company's capacity-planning standards—covering forecasting accuracy, N-0 and N-1 risk analysis methodologies, cost-effectiveness considerations, asset-sizing practices, the Capacity Risk Framework, and project-prioritization criteria—for inclusion in the 2027 IDP. ELPC/CEF/VS further recommends that the Commission direct the Company to engage stakeholders on potential modifications to its risk analysis and planning methodologies, including the application of Customer

Minutes Out (CMO) calculations and the use of emergency ratings in N-1 planning scenarios, and to report on any resulting changes in the next IDP. The Company does not support these recommendations.

Taken together, these proposals would require the Company to reopen, reevaluate, and potentially modify foundational engineering-based planning standards through the IDP and associated stakeholder processes. This would require substantial effort across multiple engineering, operations, and forecasting teams, with uncertain benefit to the IDP process. Many of the requested topics reflect long-standing utility engineering and reliability standards that are applied system-wide and are not typically re-evaluated through regulatory filings. Redirecting resources to document these standards every IDP cycle would divert attention from ongoing planning work needed to reliably serve customers and connect new customers.

In addition, the proposal risks shifting responsibility for defining technical standards from the utility to the Commission. Engineering-based standards—such as N-1 criteria, probabilistic risk evaluations, and asset-sizing methodologies—are rooted in operational expertise, equipment capabilities, and safety requirements. Introducing a Commission-driven review of these standards could create uncertainty and blur the line between regulatory oversight and technical system-design decisions.

While the Company values stakeholder understanding of its planning frameworks and continues to provide transparency regarding how risk metrics are applied, the IDP is intended to explain how existing standards are used—not to serve as a forum for stakeholder-directed redesign of core engineering methodologies. To the extent particular topics warrant further discussion, they are better addressed through focused technical dialogue rather than a blanket directive to rebuild foundational engineering criteria within a single filing.

We do not support requiring an expansive review of all planning standards in the 2027 IDP. The scope is overly broad, resource-intensive, and could blur the appropriate boundary between regulatory oversight and technical engineering standards.

## **F. Review of Other Planning Standards**

The Department recommends that the Commission establish a new planning standard review process under which the Company would identify its system planning standards by topic, select planning standards for review in coordination with intervenors, analyze alternative planning scenarios, and present quantitative

cost-benefit analyses of alternative system planning standards in future IDP filings. The Department further recommends establishing both a recurring multi-year review schedule and an ad hoc process through which intervenors could request reviews of specific planning standards. The Company does not support these recommendations.

The Company has the responsibility, authority, and technical expertise to establish and apply engineering and system planning standards necessary to ensure safe, reliable, and cost-effective service. The Company values stakeholder input and carefully considers concerns raised by intervenors regarding planning assumptions and outcomes—but decisions regarding the selection and application of planning standards are best informed by utility engineering expertise. Commission-mandated processes that direct the approval, modification, or replacement of those standards could shift core engineering judgments away from the Company and constrain the flexibility needed to respond to evolving system conditions, emerging technologies, and reliability needs. Planning standards must be able to evolve as circumstances change—and that evolution is most effectively guided by the Company's engineering expertise, grounded in data, engineering analysis, and operational experience.

In addition, the proposed recurring and ad hoc review processes would introduce significant complexity and uncertainty into the planning framework. Allowing intervenors to initiate planning standard reviews, coupled with required quantitative analyses of alternative standards and Commission approval or rejection, would materially expand the scope of the IDP and associated stakeholder processes. This would increase administrative burden, divert resources from forward-looking system planning, and potentially delay necessary investments, without a clear showing of corresponding customer benefits.

Separately, the Department recommends that the Commission require the Company to disclose all changes to its system planning standards in the IDP. The Company supports this recommendation, provided we are not required to release any proprietary or confidential information. Providing transparency regarding major changes to planning standards will help stakeholders understand how the Company's planning approach evolves over time and will facilitate more informed discussion of planning outcomes, while preserving the Company's ability to manage its system using sound engineering judgment.

## G. Retrospective Forecast Accuracy Reporting

The Department proposes creating a new IDP requirement to compare forecast accuracy across each IDP scenario (Low, Medium, High) against actual peak loads. The Company does not support this request. This analysis has already been completed in the 2025 IDP; Table 1-11 provides a direct comparison between the 2023 IDP forecast and actual 2023 and 2024 peak loads.

As explained in Chapter 1 of our 2025 IDP, differences between forecasts and actuals are *expected* and do not indicate inaccuracies. Year-to-year peaks vary due to multiple factors—weather conditions (e.g., cooler-than-average summers), changes in customer behavior, timing mismatches when new customers energize, variations in expected customer load levels, and switching events that can temporarily redistribute load across feeders. These factors naturally produce variation between actual and forecasted peaks, especially when aggregated across the entire distribution system.

Further, the Department’s suggestion misunderstands the purpose of the forecast used in the IDP. Our load forecast is a *planning* forecast, designed not to predict the most likely peak load for the upcoming year, but to identify how high peak demand *could* reasonably be under extreme but plausible conditions. This ensures that system assets are sized to reliably withstand potential peak events, not just average ones. A useful analogy is weather forecasting: operational forecasts predict tomorrow’s most likely high temperature, while planning forecasts prepare for the highest temperature historically observed on that date. In the same way, our planning forecast relies on a multiyear window of peak load history, combined with known and simulated load growth, to capture the upper range of potential system stress—not to minimize error against a single future year’s actual peak.

The Department’s request also overlooks important context: historical data for certain years is incomplete due to the transition to the LoadSEER forecasting platform, and LoadSEER’s layer-based forecast categories are not available for historical actuals. Requiring a new forecast-accuracy filing requirement would therefore repeat work already done, rely on imperfect historical datasets, and add limited value to the planning process.

For these reasons, the Company does not support establishing a new filing requirement that would duplicate existing analysis without improving the accuracy or usefulness of the IDP forecasting framework.

## H. Retrospective Project Outcome Reporting

In a similar vein to the last recommendation, the Department recommends that the Commission require all new Company spending projects with a five-year budget exceeding \$25 million, approved for cost recovery since 2021, to report five years of actual outcomes compared to forecasted outcomes in the IDP. The Company does not support this recommendation.

As an initial matter, the recommendation is unclear, particularly with respect to what the Department intends by the term “outcomes.” The Department does not specify whether outcomes are intended to reflect actual project costs, operational performance metrics, reliability impacts, customer benefits, policy objectives, or some other measure. Without clarity regarding the scope of outcomes to be evaluated, the appropriate comparison methodology, or the purpose for which such comparisons would be used, the proposed requirement lacks sufficient definition to be implemented in a consistent and meaningful manner.

Absent a clearly defined framework, the recommendation risks imposing vague, duplicative, or inconsistent reporting obligations across projects with differing objectives, timelines, and performance metrics. It is also unclear how such retrospective comparisons would account for changes in system conditions, load growth, technology costs, or regulatory requirements that may materially affect project performance relative to original forecasts.

To the extent the Department is concerned that distribution investments may reflect forecasts that ultimately prove higher than realized load growth, the Company emphasizes that forecasts are not static inputs used once and carried forward unchecked. Rather, the Company regularly updates its load forecasts as new data becomes available and routinely reassesses projected needs as part of its planning, budgeting, and project development processes. Forecast assumptions are revisited and refined prior to finalizing construction decisions, allowing the Company to adjust project scope, timing, or sequencing if warranted. This ongoing review process serves as an important safeguard against overbuilding while still ensuring that the Company meets its obligation to plan for reliable service under a range of future conditions.

Until the Department clarifies the intended meaning of “outcomes,” as well as how the proposed comparisons would be conducted, evaluated, and applied in future planning or regulatory decisions, the Company does not support the Department’s recommendation.

## I. Planned Net Loading

Stakeholders offered several comments regarding the Company's Planned Net Loading (PNL) methodology, with most recommendations focused on how the Company applies the dependability factor for photovoltaic generation ( $DF_{PV}$ ). The Department requests that the Company justify its continued use of a flat 15 percent  $DF_{PV}$  in this IDP cycle, asserting that the data presented in the filing suggests higher values may be appropriate for certain months. The Department also encourages the Company to evaluate whether seasonal  $DF_{PV}$  values could be implemented sooner than the 2027 IDP, noting that the foundational data is already included in the current filing. ELPC/VS/CEF further recommend that the Commission require the Company to file an interim PNL update by December 31, 2026, including evaluation of stakeholder-proposed methods, specification of seasonal dependability factors and months, and analysis of associated impacts, with implementation addressed in the 2027 IDP.

We appreciate stakeholder engagement and agree that establishing accurate and reliable  $DF_{PV}$  values is critical to assessing net load risk and informing mitigation decisions. As described in Chapter 1, Section IV.B of the 2025 IDP, the 15 percent  $DF_{PV}$  used in this IDP cycle was derived from five years (2016–2021) of recorded PV output from Minnesota community solar garden installations. The analysis showed PV output falling as low as 12 percent in December. Averaging the three lowest-production months—December, January, and November—yielded 15.04 percent, supporting a conservative 15 percent factor to ensure system reliability. This approach is consistent with the Commission's September 16, 2024 Order, which explicitly directs the Company to implement a 15 percent  $DF_{PV}$  for N-0 risk analysis in this planning cycle.

We also recognize stakeholder interest in transitioning to more granular seasonal  $DF_{PV}$  values. As explained in our filing, we have conducted substantial stakeholder engagement on this topic and developed a seasonal framework that will be implemented in the 2027 IDP. The 2027 IDP is the next opportunity to present PNL results incorporating seasonal values and accelerating implementation is not feasible given the timing and structure of the current cycle. With respect to requests for an interim filing, we do not believe additional filings are necessary. We have already evaluated stakeholder-proposed methods and seasonal  $DF_{PV}$  values will be fully detailed in the 2027 IDP; any required compliance items can be incorporated into the November 1 compliance filing rather than creating duplicative reporting requirements.

The Company's current approach aligns with Commission direction, reflects conservative and data-driven analysis, and positions the PNL methodology for further refinement through the adoption of seasonal  $DF_{PV}$  values in the next planning cycle. We will continue engaging with stakeholders as we enhance PNL assumptions and tools. For these reasons, we do not support the PNL recommendations.

## **J. Incorporating Equity Considerations into the Planning Process**

ELPC/VIS/CEF recommends that the Company establish equity-informed prioritization criteria in project scoring, formally integrate equity into the IDP process, and begin reporting equity outcomes by environmental-justice area, income, and race before November 1, 2027.

While we appreciate the intent behind these recommendations, they are insufficiently defined, making it unclear what specific planning changes are being requested. As we noted in our 2023 IDP Reply Comments, the Company is actively engaged in integrating equity across a broad range of energy and workforce initiatives. This work is ongoing through the Environmental Justice Accountability Board and other Commission-directed processes. A comprehensive overview of the Company's equity-focused efforts is provided in its 2025 Annual Report *In the Matter of Efforts to Advance Workforce Diversity, Inclusive Participation, and Equitable Access to Utility Services for Xcel Energy*.<sup>1</sup> Minutes of EJAB's bimonthly meetings are filed in the same docket, and additional detail is included in testimony submitted in the Company's Minnesota electric Multiyear Rate Plan proceeding.<sup>2</sup>

For these reasons, we do not support these recommendations.

## **II. COST BENEFIT ANALYSIS**

Stakeholders recommend expanding Cost Benefit Analysis (CBAs) across many planning areas. The Company supports targeted, methodologically sound CBAs where they add clear value and our modeling capabilities can produce reliable results, but we do not support blanket mandates (e.g., for all Asset Health & Reliability (AH&R) programs, all undergrounding projects, or all Distributed Energy Resource

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<sup>1</sup> Northern States Power Company, doing business as Xcel Energy. ANNUAL REPORT. *In the Matter of Efforts to Advance Workforce Diversity, Inclusive Participation, and Equitable Access to Utility Services for Xcel Energy*. Docket Nos. E-002/M-22-266 and E-002/RP-19-368. December 29, 2025.

<sup>2</sup> Direct (November 1, 2024) and Rebuttal (October 10, 2025) Testimony of Nicholas F. Martin *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*. Docket No. E-002/GR-24-320.

Management System (DERMS) use cases). We are also concerned by the sheer number of new CBA requests and the highly resource intensive analysis they would require in a proceeding that is intended to be a planning report—not a prudency review.

The Company emphasizes that cost benefit analyses are one tool used to inform investment decisions, but they are not the sole determinant. CBAs must be applied where fit for purpose and considered alongside engineering judgment, risk-based planning, and the Company's fundamental obligation to provide safe and reliable service. In some circumstances, the Company must proceed with investments to meet reliability, safety, or service obligations regardless of whether those investments yield a favorable economic outcome under a CBA framework. The Company will continue a measured, stepwise expansion of CBA use where appropriate, transparently document methodologies and assumptions, and address CBA requirements in the appropriate regulatory venues—while ensuring that critical reliability work and prudent investments are not delayed in a rapidly evolving grid.

We now turn to the fourteen CBA recommendations and provide our responses.

#### **A. Grid Reinforcement – Forward-Looking CBA**

Fresh Energy recommends requiring the Company to include a forward-looking CBA demonstrating that customer benefits exceed costs for planned Grid Reinforcement expenditures in future IDPs or rate cases. The Company does not support this recommendation.

We agree that transparent valuation is important and note that we have already conducted a CBA for Grid Reinforcement using historical data and validated methods. As electrification, electric vehicle (EV) adoption, and Distributed Energy Resource (DER) growth accelerate, timely reinforcement is essential to preserve reliability and customer service quality; in many cases, reinforcement is the least cost path to meeting service quality obligations when localized constraints emerge.

At the same time, a forward looking, systemwide CBA is materially different from a retrospective evaluation. Producing a credible, prospective valuation requires mature, integrated modeling that can (1) trace feeder and substation level constraints back to specific demand drivers, (2) incorporate location specific options and staging (e.g., targeted upgrades versus deferral tools), (3) capture risk and uncertainty (e.g., range of EV/heating adoption, customer energization timing), and (4) avoid double counting

benefits already reflected in baseline reliability. Those capabilities are advancing but are still maturing within our planning tool chain; accordingly, a measured approach is warranted. We intend to incrementally expand and progress CBA methods over successive planning cycles rather than move from “zero to full scope” in a single filing.

Thus, we do not recommend mandating a comprehensive forward-looking CBA for all planned Grid Reinforcement expenditures. Our modeling capabilities are evolving, and a phased buildout will yield more accurate and value-add analysis without diverting resources from essential reliability work.

## **B. Expand CBAs to Additional Asset Health & Reliability Programs**

Fresh Energy recommends expanding CBAs to additional AH&R categories—including our Line Equipment Renewal, Pole Related Renewal, and Cable Replacement.

While we share the goal of transparent valuation, the Company does not support a blanket CBA expansion across these AH&R programs for several reasons:

- **Mandatory vs. discretionary work.** Prior Commission Orders have focused CBA development on *discretionary* programs; by contrast many AH&R activities become *mandatory* once certain inspection thresholds are met (e.g., structure strength criteria set by National Electric Safety Code). When inspection programs identify poles, cables, or other equipment that must be replaced, the Company is obligated to act; a program level CBA does not change the underlying safety requirement and may simply add process, cost, and delay.
- **Risk reduction is often qualitative and long horizon.** CBAs can undervalue staged, proactive renewal strategies that avoid clustered failures years later, favoring short-term mitigations over long-term asset health improvements. For example, steady pole renewal “in small bites” can prevent future largescale deterioration that would harm reliability and strain resources—benefits a narrow CBA may not fully capture.
- **Dynamic programs and budgets.** AH&R portfolios are actively managed; dollars can shift between proactive and reactive work (including within our Line Equipment Renewal, Pole Related Renewal, and Cable Replacement

programs). A rigid CBA requirement can constrain that management flexibility and reduce the program's ability to respond to evolving field conditions.

For these reasons, we do not support the recommendation for a blanket CBA expansion. As discussed during our stakeholder engagement workshops on CBAs, the Company will continue a measured, stepwise expansion of CBA use in future IDPs. This approach will prioritize discretionary segments with clearly quantifiable benefits, while preserving the flexibility needed to complete mandatory safety and reliability work in a timely manner.

### **C. CBA for at least Three Discretionary Programs**

The Department recommends that the Company provide a CBA for at least three discretionary programs with a combined five-year budget  $\geq$  \$250 million in the Distribution System Optimization portfolio.

We support conducting CBAs for three discretionary programs in the 2027 IDP. However, we do not support establishing a fixed dollar threshold. A pre-set minimum—such as \$250 million—presumes future budgets and could inadvertently incentivize selecting programs based on meeting an accounting target rather than addressing system needs. Such a requirement may distort prioritization and undermine the purpose of discretionary planning.

Instead, we propose identifying three discretionary programs that have:

- clear, quantifiable benefit streams (such as avoided Customer Minutes Out (CMOs) or targeted operations and maintenance (O&M) savings),
- stable and reliable data inputs, and
- no mandatory components triggered by inspection thresholds or safety requirements.

For each selected program, we will apply consistent, transparent methods—including common assumptions on unit costs, sequencing, and discounting where appropriate—and we will clearly note any limitations or qualitative co-benefits not captured in the model. This approach maintains analytical rigor without compromising operational flexibility or diverting resources away from essential reliability work.

#### **D. Define “Discretionary,” Enumerate Benefits, and Develop Program-Level Methods**

CEF/ELPC/VS recommended that we continue and deepen stakeholder work to define “discretionary,” enumerate benefits, and develop program level CBA methods. We agree that continued collaboration is useful; however, no stakeholder objected to the Company’s working definition of “discretionary” as presented in prior stakeholder workshops and summarized in the stakeholder report for this IDP. In addition, we have already committed to add tangible, known, and quantifiable benefits/costs and to expanding the set of programs in the CBA framework in each subsequent IDP.

Accordingly, we see no need to reopen or revisit foundational definitions that have already been accepted. Our focus is to enhance methods and scope iteratively, where they are most decision-useful and supported by available data and modeling maturity.

For these reasons, the Company does not believe additional Commission direction on this issue is necessary.

#### **E. Wildfire Mitigation & Targeted Undergrounding CBAs**

The Department recommends that we provide a full CBA for the wildfire-mitigation budget. The Department also recommends requiring a full CBA for all post-2026 targeted undergrounding projects, incorporating O&M savings and site-specific costs/benefits.

We have discussed our position on these recommendations in Sections VI and VII.

#### **F. Programmatic CBAs**

The Department recommends that we provide estimates of undepreciated asset costs within programmatic CBAs. The Company does not support this recommendation. Tying undepreciated asset costs to individual capital programs does not align with how the Company manages its capital portfolio or how assets are depreciated for accounting purposes. The Company applies a group depreciation approach, under which assets are depreciated collectively rather than tracked and retired on a program specific basis. As a result, attempting to attribute undepreciated asset values to individual programs would require significant additional analysis and manual effort, without producing information that meaningfully improves the accuracy or usefulness of programmatic CBAs. Given the limited incremental value of this information

relative to the substantial time and resource investment required, the Company does not believe this requirement is appropriate for inclusion in programmatic CBA analysis.

The Department also recommends discounting all benefit calculations used in programmatic CBAs. The Company supports this recommendation. Applying discounting promotes consistency with standard utility and regulatory financial practices by recognizing the time value of money when comparing costs and benefits that occur over different periods. The Company will incorporate appropriate discounting methodologies in future programmatic CBAs, consistent with the scope and purpose of those analyses and in the appropriate regulatory context.

### **G. Overload Outage Benefits**

The Department asks the Company to explain why Attachment M does not calculate the marginal reliability benefit of substation overload outages (Customer Minutes Out) and, if the calculation is revised, to explain why the resulting benefits differ significantly from the Company's existing approach.

The Department's request is unclear with respect to what is meant by the "marginal" reliability benefit of substation overload outages. Attachment M does not apply a marginal or incremental benefit calculation for overload related CMO; rather, it presents multiple analyses intended to illustrate the reliability risks and customer impacts associated with substation overload conditions and the benefits of mitigating those risks.

Specifically, Attachment M evaluates reliability benefits through three complementary lenses: (1) historical substation equipment outage performance and associated CMOs, (2) the cost and reliability implications of emergent versus proactive replacement of substation breakers, and (3) the relationship between transformer age and the occurrence of overload conditions. Together, these analyses are intended to demonstrate the reliability value of substation investments and to contextualize overload-related risk, rather than to isolate a separate marginal benefit metric.

The Company is therefore unsure what additional information or alternative calculation the Department is seeking to better demonstrate the reliability benefits of mitigating substation overload outages. The analyses provided in Attachment M reflect the Company's established planning and risk assessment approaches and are designed to inform system-level investment decisions.

Absent additional clarity regarding the specific information or methodology the Department believes is missing, the Company does not support this recommendation.

#### **H. Treatment of Operations and Maintenance Costs**

The Department asks Xcel to clarify whether O&M costs are included in the total cost calculations in Attachments M and N and, if not, to explain why those costs were excluded.

The Company confirms that O&M costs are included in the total cost calculations presented in Attachments M and N. These costs are incorporated within the emergent cost component of the analysis, which reflects the additional labor and related expenses associated with responding to unplanned equipment failures or emergent work. While O&M costs are not separately itemized in these attachments, they are captured as part of the emergent cost calculation used to compare proactive and reactive investment approaches.

#### **I. Treatment of CBA Assumptions and Inputs**

Fresh Energy recommends several changes to the Company's CBA framework, which the Company addresses below.

First, Fresh Energy recommends relying exclusively on ex-ante or forward-looking CBAs to estimate the customer costs and benefits of planned program expenditures. While the Company agrees this is an important long-term objective, it does not support mandating this approach at this time. Developing credible, prospective CBAs requires integrated, systemwide modeling capabilities that are still maturing. Accordingly, the Company is taking a measured, stepwise approach to expanding CBA methodologies as data and tools continue to improve.

Second, Fresh Energy recommends reflecting the present value of costs—measured as revenue requirements—and benefits over the life of assets in CBAs. The Company agrees with this recommendation and will structure its CBAs on a present value basis over relevant asset lives.

Third, Fresh Energy recommends using only the average age of substation breakers for the Breaker Equipment Life Replacement CBA and the average age of substation transformers for the Grid Reinforcement CBA. The Company does not support this

recommendation, as reliance on average age alone would obscure important differences in asset condition, utilization, and overload risk.

Finally, Fresh Energy recommends eliminating the estimate of overload-related CMO based on the relationship between asset age and overload conditions in the Grid Reinforcement CBA. The Company does not support this recommendation. While older equipment is generally more likely to experience failure under overload conditions, risk varies based on multiple factors beyond age alone. Continued refinement of data and analysis is therefore preferable to applying a sweeping average.

## **J. Ten-Year CBA Updates**

The Department recommends that the Commission require the Company to provide an update to each program CBA ten years after the initial presentation of the analysis. The Company does not support this recommendation.

The Company's distribution planning and investment decisions are made within a five-year budgeting and planning horizon, which aligns with how programs are scoped, approved, and managed. Many programs are designed to address near to midterm system needs, evolving technologies, or specific policy objectives, and may be modified, replaced, or discontinued well before a ten-year mark. For example, pilot programs testing new grid technologies, targeted reliability initiatives addressing localized constraints, or programs responding to emerging DER adoption trends may conclude after several years or be folded into broader system planning efforts. Requiring CBA updates ten years after initial approval would therefore impose analysis obligations for programs that may no longer exist, have materially changed in scope, or no longer reflect current system conditions.

In addition, the Company must retain flexibility to reprioritize investments as emerging trends, operational experience, and changing customer and system needs arise. For instance, load growth patterns, electrification adoption, interconnection volumes, and technology costs can shift significantly over time, prompting the Company to redirect funding toward higher-priority reliability, resilience, or capacity needs. A prescriptive requirement to revisit decade-old CBAs could constrain that flexibility and divert limited analytical resources away from forward-looking planning activities, such as evaluating new system needs or optimizing near-term capital deployment, where those resources provide greater value to customers.

For these reasons, the Company does not support the Department’s recommendation. Existing planning filings, program reviews, and stakeholder processes already provide appropriate transparency into program performance and distribution system optimization without imposing rigid, long-term CBA update requirements that offer limited incremental value to customers.

#### **K. DERMS – CBA for all Planned Use Cases**

The Department recommends providing a CBA in the next IDP for all planned use cases of Aggregator DERMS, Grid DERMS, and Enterprise DERMS for 2027–2032.

The Company does not support this requirement for several reasons:

- **Use-case definition is incomplete.** Enterprise DERMS has not been fully specified, and the set of applicable use cases, data integrations, and operational guardrails remains under development. Preparing CBAs for “all planned use cases” presumes stable scope, inputs, and dispatch logic that do not yet exist.
- **Limited rollout by design.** Grid DERMS is being deployed on a limited basis to test practical functionality (e.g., telemetry, device registration, operator workflows) before scaling. A comprehensive, multi-year CBA is not methodologically fit in a pilot/validation phase where results are meant to inform the eventual business case.
- **Avoiding double-counting and misallocation.** DERMS value can overlap with other portfolios (e.g., Non-wires alternatives (NWA screening), flexible interconnection (FI) enablement, DR enablement). Without settled measurement boundaries, a multi-use-case CBA risks double-counting or attributing benefits that belong to other programs, producing misleading signals for investment prioritization.

#### **L. Expanded Reporting Requirements for Large Distribution Projects**

The Department recommends that the Commission create a new filing requirement under which all new distribution spending projects and programs with an estimated historical or forecasted five-year budget of \$25 million or greater must, at minimum, address estimated project costs, feasible alternatives, quantitative expected outcomes, and sensitivity analyses of cost and outcome assumptions. The Company does not support this recommendation as proposed.

The IDP is intended to be an informational planning document that describes system needs, planning assumptions, and anticipated investments. It is not a cost-recovery filing, and the Company does not seek approval of specific expenditures or recovery of costs through the IDP.

Requiring this expanded reporting within the IDP would blur the distinction between planning and ratemaking proceedings and would substantially increase the analytical burden associated with an otherwise informational filing. If the Commission were to require this level of detailed analysis for all qualifying projects and programs in the IDP, the Company would need to seek significant additional staffing resources to support the development, review, and maintenance of these analyses. Diverting resources to produce highly detailed project-level reporting in the IDP would reduce the Company's ability to focus on forward-looking system planning and near-term operational priorities.

For these reasons, the Company does not support the Department's recommendation.

### **III. ASSET HEALTH & RELIABILITY PLANNING**

In this section, we address recommendations and requests from Fresh Energy and the Department regarding our Asset Health and Reliability (AH&R) projects and programs.

#### **A. AH&R Budget Structure and Use of Program-Level Funding**

Fresh Energy recommends that we provide greater transparency into our methodology for prioritizing AH&R projects and programs, including how associated budgets are established. Fresh Energy asserts that the AH&R budget is overly opaque due to the use of "placeholders." The Company does not agree with this characterization and provides the following clarification.

AH&R investments are inherently multi-year and adaptive in nature. Funding that has been described as "placeholders" reflects standard asset management practice across the utility industry, where specific projects cannot always be identified several years in advance. These budget allocations represent funding for working capital, blanket projects, and programs intended to address emerging reliability risks, unforeseen asset failures, storm damage, and evolving system conditions. The Company establishes

these budget levels based on historical investment trends, asset age and condition data, failure history, and reliability performance metrics. This approach ensures that funding is available to respond to real-world conditions as they arise, while allowing project scopes to be refined as more detailed information becomes available in future planning cycles.

Therefore, the Company does not support this recommendation.

## **B. Quantification of Reliability Benefits for AH&R Investments**

Fresh Energy also recommends that the Company develop a methodology to quantitatively estimate the expected reliability improvements associated with AH&R expenditures. While the Company supports transparency and continues to enhance its planning tools, it does not support a requirement to quantify reliability benefits across all AH&R investments using a single standardized methodology.

Reliability outcomes vary significantly by asset type, location, operating environment, and weather conditions. In addition, a substantial portion of AH&R spending is reactive in nature—such as replacing assets damaged by storms, vehicle impacts, or sudden failures—making it difficult to forecast project-level reliability benefits several years in advance. Developing a universal predictive model under these conditions risks producing results that are inconsistent, misleading, or not useful for decision-making.

The Company also notes that AH&R planning differs fundamentally from capacity-driven planning processes, which rely on project-level risk scoring tools and predefined work bundles. Transitioning AH&R planning to a similar framework would represent a significant departure from current practice and would require substantial investment in new technology, systems, and dedicated staffing resources. While the Company is open to continued evolution of its planning processes over time, such changes would require careful consideration, sustained investment, and appropriate cost-recovery mechanisms.

For these reasons, the Company does not support this recommendation.

## **C. Use of Overload Customer Minutes Out in Risk Assessment**

Fresh Energy requests additional explanation of the Company’s use of “overload customer minutes out” (CMO) as part of its AH&R risk-scoring framework.

The Company clarifies that overload CMO is an established planning metric used to quantify potential reliability risk when equipment exceeds its thermal limits. The metric is intended to identify and compare relative risk exposure—not to predict the likelihood of a specific outage. The Company calculates overload CMO based on factors such as the extent to which an asset exceeds its rating, customers served per unit of capacity, forecasted demand growth, and the number of hours during which an asset is at risk. Distinct methodologies are applied for N-0 and N-1 conditions to reflect the differing nature of intact-system and contingency risks.

#### **D. FLISR Data Granularity and Reporting**

The Department recommends that the Commission require the Company to include data on all individual FLISR installations in a single dataset, including circuit-level identifiers, installation year and cost, and reliability savings, consistent with information reported in Attachment D of IR 49, beginning with the next IDP.

The Company does not support this recommendation. The reporting provided in Attachment D of IR 49 was prepared in response to a discrete information request and served a specific, limited purpose. As reflected in the Company's response to IR 49, even where circuit- or device-level information is provided to respond to such a request, that information necessarily relies on simplified definitions and assumptions that do not reflect how FLISR is planned, deployed, or delivers value as an integrated system. For that reason, this level of granularity is not appropriate for ongoing IDP reporting or circuit-level cost-benefit analysis.

FLISR is deployed and operated as an integrated system. Installations are planned, programmed, and commissioned in coordinated groups across multiple feeders, with reliability benefits that are inherently shared and system-wide. As a result, attempting to disaggregate installation costs or assign reliability savings to individual FLISR components or circuits for IDP reporting would not accurately reflect how the system functions or delivers value.

Because FLISR benefits arise from the performance of the system as a whole, conducting circuit-level cost-benefit analysis or reporting reliability impacts at the level of individual installations would be analytically unsound and potentially misleading. The Company therefore believes that system-level reporting, rather than asset-level disaggregation, remains the appropriate approach for the IDP and does not support expanding Attachment D–style reporting into a standing IDP requirement.

#### IV. FLEXIBLE INTERCONNECTION

Stakeholders—including MnSEIA, SEIA, CCSA, ELPC/VS/CEF, and Fresh Energy—assert that static flexible interconnection (FI) is technically feasible today, does not require DERMS functionality, and would give developers a way to avoid costly distribution upgrades. They therefore recommend that static FI be implemented before dynamic FI to comply with Order Point 19 of the Commission’s September 16, 2024 Order in Docket No. E002/M-23-452, which states:

*Xcel shall demonstrate the Company’s ability to integrate DERs with the tools available to it today and in the near term, including specifically through:*

- a) Implementing static Flexible Interconnection prior to implementing full dynamic Flexible Interconnection; and*
- b) Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.*

CEF/ELPC/VS and Fresh Energy further recommend that the Commission require the Company to file a FI progress report by the end of the year and provide an additional update in the 2027 IDP. Fresh Energy additionally urges the Company to incorporate technical recommendations for static FI from the DGWG’s new FI subgroup, review Ameren and CHARGED program materials when designing a static FI offering, and coordinate FI with cost shared upgrade mechanisms—such as DSRUP—as well as proactive upgrades, allowing DERs to interconnect quickly using FI and later benefit from reduced curtailment once upgrades are completed. These stakeholders also argue that the Company’s current approach does not comply with Order Point 19.

We appreciate stakeholder engagement and agree that FI is an important tool for enabling DER growth. As an initial matter, the Company is complying with Order Point 19 by demonstrating its ability to integrate DERs using both current and near-term tools and by implementing a staged approach to Flexible Interconnection, DERMS, and hosting capacity improvements. As outlined in our filing, we evaluated static FI and identified its operational limitations, and we are prioritizing implementing dynamic FI because it provides greater system efficiency and aligns directly with the planned DERMS deployment beginning in 2026.

The Company has established a clear phased implementation plan—starting with limited DERMS deployment on five to ten feeders in 2026, followed by broader dynamic FI and hosting capacity integrations—which satisfies Order Point 19’s staged approach requirement and ensures that FI capabilities expand alongside foundational

grid modernization investments. To the extent stakeholder recommendations would direct the specific sequencing, design, or operational parameters of FI, those recommendations move beyond policy considerations and into engineering and system planning standards. Establishing and applying those standards is within the Company's technical expertise and responsibility to ensure safe, reliable, and efficient system operations, and must remain grounded in operational realities.

We now respond to the remaining assertions regarding FI.

### **A. Prioritizing Dynamic FI Over Static FI**

The Company continues to recommend a **dynamic first approach** for the reasons summarized below.

- **Static FI is Feasible but Presents Significant Limitations.** Static FI is technically feasible with the same interconnection requirements as dynamic FI and requires the same hardware and communication links as dynamic FI. Because static schedules cannot benefit from real-time forecasting, they may result in more frequent curtailment and reduced system utilization, ultimately diminishing customer value. Moreover, neither static nor dynamic FI are currently a standard interconnection offering in Minnesota. The DGWG's FI subgroup—which began meeting on February 18, 2026—is still developing the technical requirements necessary before any tariff or MNDIP updates can be considered by the Commission. We anticipate that by the time this work is complete, our limited DERMS deployment and the technical ability to implement dynamic FI will already be in place.
- **Dynamic FI Provides Superior Efficiency, Scalability, and Customer Value.** We recommend prioritizing dynamic FI because it:
  - Aligns curtailment with real-time grid conditions;
  - Reduces unnecessary curtailment and improves impacts to DER production revenue;
  - Leverages DERMS to support scalable and interoperable FI deployment;
  - Avoids diverting resources to a short-lived or limited-value static solution;
  - Supports a consistent, system-wide approach to FI implementation.

We remain on track for limited DERMS deployment in Q3 2026, enabling dynamic FI on five to ten feeders selected for early use case validation. Since static and dynamic

FI share foundational requirements—such as interconnection studies and DER-to-utility communication equipment—moving directly to dynamic FI is more efficient and avoids duplicative effort.

## **B. Requests for Reports and IDP Updates**

The Company will continue providing FI related- updates in future IDP filings. Although not opposed to reporting progress, we note that implementing static FI would require procedural and tariff changes to the MNDIP, which must occur through the DGWG and Commission processes. Consistent with Order Point 20<sup>3</sup>, we remain committed to transparency with DER owners and operators regarding the conditions under which FI may be used.

## **C. Recommendations to Adopt Ameren/CHARGED Models**

Recommendations that the Company adopt specific external FI program designs are unnecessarily prescriptive. Stakeholders seeking alignment with other jurisdictions should identify specific components they believe are applicable. The Company will continue to evaluate industry best practices but does not support mandates to follow any single prescriptive model.

In sum, while we acknowledge stakeholder concerns, the Company continues to believe that dynamic FI—enabled by DERMS—is the most effective, durable, and scalable solution. We remain committed to transparency, active participation in DGWG processes, and providing developers with the information needed to evaluate potential curtailment impacts and make informed interconnection decisions. We do not believe additional Commission direction is necessary at this time.

## **V. FERC ORDER 2222**

Stakeholders provided several comments on the Company's discussion of FERC Order 2222. MnSEIA, SEIA, and CCSA argue that Order 2222 does not create new state responsibilities and believe the Company overstates the role of state regulators in its IDP discussion. While acknowledging that the Company met the IDP requirement to summarize Order 2222 implications, they urge the Commission to launch an investigatory proceeding to address broader coordination needs, including harmonizing MNDIP with DERA registration rules, streamlining the 60-day

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<sup>3</sup> Order Point 20 of September 16, 2024 ORDER states: Xcel shall be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owners/operators.

aggregation-review timeline, clarifying dual-participation policies, establishing data access and telemetry requirements, and reviewing whether the Company has fully leveraged prior grid-modernization investments. CEE adds that evolving market and policy developments—including MISO’s ongoing implementation steps—support a prudent, staged approach to DERMS and related distribution-system capabilities.

We appreciate stakeholder feedback and agree that Order 2222 presents significant operational, regulatory, and technological coordination challenges for distribution utilities. We also clarify that we are *not* asserting new legal obligations for states; rather, we are identifying areas where state-level coordination may help avoid duplicative investments, unclear cost allocation, and data-management challenges that could affect Minnesota customers. Any changes to the distribution interconnection process remain squarely within the Commission’s authority.

While we recognize stakeholder interest in a broader proceeding, we believe existing regional and state forums are the most efficient venue for continued work. Our IDP already identifies the key implementation considerations for Order 2222, and a new Commission-led docket could duplicate efforts underway at MISO—particularly through the Distributed Energy Resource Task Force (DERTF)—and increase regulatory burden without yielding earlier or more effective outcomes. In addition, rulemaking on issues such as dual participation or telemetry is premature given that MISO’s final market design and tariff implementation will not be complete until 2029–2030.

The Company’s staged DERMS roadmap was designed to align with MISO’s evolving Order 2222 timeline, allowing us to build the data, coordination, and system-visibility tools needed while avoiding premature over-building. We will continue monitoring MISO’s implementation cadence and remain actively engaged through DERTF and related processes.

While we acknowledge stakeholder concerns, we believe continued engagement through existing state and regional stakeholder processes remains the most effective path forward. We remain committed to transparency, close coordination with MISO, and ensuring that Minnesota is well prepared for wholesale DER aggregation. At this time, we do not believe additional Commission action is necessary.

## VI. WILDFIRE MITIGATION

Stakeholders submitted several recommendations related to wildfire risk assessment and wildfire mitigation planning.

ELPC/VS/CEF recommend that by December 31, 2026, the Company file a Minnesota specific wildfire risk assessment comparing Minnesota's wildfire profile to other Xcel Energy jurisdictions, evaluating wildfire risk relative to other safety and reliability concerns, and linking this analysis to investment proposals. While we recognize the importance of robust wildfire risk analysis, we do not believe this work can be completed on the timeline requested. Instead, we propose incorporating this broader assessment into the comprehensive Wildfire Mitigation Plan (WMP) currently under development and planned for filing in 2027.

The Department provided several additional recommendations. It first suggests incorporating locational information from the Company's medically necessary equipment certification form into wildfire mitigation planning. The Company notes that this information is already integrated into internal efforts but cannot be shared publicly due to customer privacy protections.

The Department further recommends consolidating wildfire mitigation proposals occurring outside of rate case test years into a comprehensive WMP, filed as an attachment or supplement to future IDPs. The Company agrees with this approach.

The Department also proposes that the WMP include several specific elements: a clear statement of the Company's wildfire mitigation intent; a definition of "wildfire" for planning purposes; descriptions of risk modeling, prioritization, and mapping processes; an updated wildfire risk map with narrative explanation; historical wildfire and outage data; an assessment of mitigation strategy effectiveness; and information about the Company's Public Safety Power Shutoff (PSPS) program, including outage counts, durations, causes, customer notification practices, and protections for medically vulnerable customers. It further recommends providing the Wildfire Safety Operations Playbook, PSPS Playbook, and PSPS Communications Playbook. The Company agrees with all these recommendations but notes that ten years of outage related wildfire data may not be available.

Finally, the Department recommends performing a full CBA for wildfire mitigation measures. The Company supports conducting CBAs where appropriate and is developing cost benefit-related analysis for certain wildfire mitigation programs,

which will be incorporated into the planned WMP filing. However, the Company does not support evaluating all wildfire mitigation measures—or developing wildfire mitigation portfolios—exclusively through CBAs or cost benefit ratios (CBRs). In particular, the Company does not plan to develop CBRs for foundational or control type programs that are designed to maintain risk at current or acceptable levels (such as vegetation management), as these programs are compliance-driven or infeasible to model with available data.

Further, many key benefits—such as reducing ignition risk, protecting medically vulnerable customers, and avoiding catastrophic losses—are difficult to quantify and often rely on incomplete historical data. In some cases, wildfire-related outage data does not extend back ten years, further limiting the usefulness of purely economic analysis. For these reasons, wildfire mitigation portfolios should be developed using multiple sources of information, including CBA results where available, operational feasibility, and risk tolerance for severe consequences. This approach also recognizes that the Company’s understanding of wildfire risk and mitigation effectiveness continues to evolve over time.

The Company remains committed to transparent, risk-based planning and to strengthening wildfire mitigation practices through the forthcoming WMP. The Company supports integrating most of the Department’s recommendations into the comprehensive WMP to be filed with the 2027 IDP. However, we disagree with requests for a separate Minnesota specific risk assessment by 2026 or mandating CBAs in all cases. As discussed above, CBAs are one input to wildfire mitigation decision-making and should be applied where appropriate, alongside operational feasibility, engineering judgment, and consideration of low frequency, high consequence risks.

## **VII. TARGETED UNDERGROUNDING**

Stakeholders offered several recommendations on targeted undergrounding.

ELPC/VIS/CEF urge the Company to integrate equity considerations earlier in the process, use the LBNL ICE 2.0 tool to support prioritization, and provide annual reporting on project counts, costs, and representation in environmental-justice areas. The Company finds these recommendations vague and notes that the ICE tool inherently favors higher-usage, higher-income communities, limiting its usefulness for equitable prioritization. Because targeted undergrounding is a capital-expenditure

program, the Company must also adhere to the Commission-ordered third-party equity study before modifying its approach.<sup>4</sup>

The Department recommends requiring full benefit-cost analyses (BCAs) for all post-pilot projects and incorporating O&M savings and site-specific construction estimates. The Company opposes project-level BCAs because they are administratively burdensome for small distribution projects and are not well suited to situations where the Company has a service-quality obligation. Instead, the Company already applies a least-cost, highest-benefit approach, prioritizing sites with the highest CMOs and strong technical and financial feasibility.

Regarding the company's value of lost load (VOLL) estimate, the Company's ICE 2.0 based calculation utilized the Company's actual residential load share. The resulting \$/CMO values closely align with MISO's approved System VOLL of \$35,000/MWh<sup>5</sup>, with slight differences due to inflation and customer-specific factors.

The Department further recommends new site-selection requirements—a minimum BCR of 1.25, limits tied to asset depreciation, and formal quantification of alternatives such as vegetation management, FLISR, and back-lot O&M. The Company opposes these changes, as strict BCR thresholds and depreciation-based screening could prevent focus on the feeders with the most significant outage impacts. Alternatives are already considered, but undergrounding remains necessary in areas where service-quality obligations require a durable solution regardless of strict cost-benefit ratios.

For these reasons, we do not support these recommendations. The Company believes its current prioritization process strikes the appropriate balance among reliability improvement, feasibility, and cost, and should continue to be guided by the Commission-ordered equity study and existing reliability-focused planning practices.

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<sup>4</sup> See ORDER ACCEPTING REPORT AND SETTING ADDITIONAL REQUIREMENTS at Order Point 46, *In the Matter of Xcel Energy's 2023 Annual Safety, Reliability, and Service Quality Report*, Docket No. E002/M-24-27 (Jan. 13, 2025) (“Xcel must hire an independent third-party evaluator with expertise in evaluating racial disparities to conduct a one-year study that will evaluate Xcel’s practices and policies related to capital investment planning, outage restoration practices, and shutoff practices to better understand the causes of these discrepancies in shutoff rates and service reliability. Xcel must engage interested stakeholders to participate and collaborate with the independent third-party evaluator.”).

<sup>5</sup> FERC Docket No. ER25-579-000

## **VIII. GRID MODERNIZATION**

This section addresses comments, requests, and recommendations regarding the Company's grid modernization efforts.

### **A. Support for the DERMS Roadmap and Alignment with Market Developments**

The Company appreciates the Center for Energy and Environment (CEE) coalition's support for the DERMS roadmap and its recognition that the Company's phased approach aligns with leading industry practices. A stepwise DERMS deployment avoids one-size-fits-all solutions, manages implementation risk, and allows the Company to deliver incremental customer value while controlling costs.

The Company further agrees that evolving market and policy developments—including MISO's ongoing resource adequacy and local market enhancements and the implementation of FERC Order 2222—support a deliberate, sequenced DERMS strategy. The DERMS roadmap was designed to align with these external timelines and requirements, enabling the Company to meet emerging coordination, telemetry, and operational obligations without prematurely over-building DERMS capabilities. The Company will continue to monitor MISO and federal implementation efforts and adjust its DERMS development path as appropriate.

### **B. Incorporation of DERMS into Localized Grid Planning and Non-Wires Alternatives**

The Department requests that the Company explain whether, and how, it intends to incorporate localized grid benefits from DERMS into its standard load forecasting, hosting capacity assumptions, and NWA processes. The Company appreciates the Department's interest in understanding any potential future role of DERMS in distribution planning.

As described in the IDP, the Company has developed a phased DERMS roadmap and is currently in the early stages of limited DERMS deployment. At this stage, the Company is still evaluating how DERMS capabilities—particularly with respect to FI, DER behavior, telemetry, and operational integration—will perform in practice. DERMS functionality, use cases, and data availability are still evolving. The Company seeks to better quantify localized DERMS driven grid benefits before considering

their potential incorporation into standard planning assumptions or NWA screening processes.

The Company expects that lessons learned from its limited DERMS deployment will inform future planning integration as capabilities mature and performance becomes better understood. The Company will continue to evaluate opportunities to reflect DERMS benefits in distribution planning over time, consistent with system needs, operational experience, and regulatory developments.

### **C. DERMS Vendor Strategy and Phased Deployment Approach**

The Department also requests clarification regarding whether the Company intends to contract with a single vendor for Aggregator DERMS and Grid DERMS solutions, or whether it anticipates engaging multiple vendors. As discussed in Chapter 11 and Table 11-1 of the IDP, the Company has intentionally adopted a phased, parallel deployment strategy.

For the upcoming limited DERMS deployment, the Company is utilizing one vendor for Grid DERMS and one vendor for Aggregator DERMS. This approach allows the Company to evaluate functionality, interoperability, performance, and integration risks before committing to a broader enterprise-level solution. Looking ahead, the Company's long-term objective is to integrate both platforms into an Enterprise DERMS solution.

### **D. Addressing Local Capacity Constraints**

Fresh Energy recommends that the Company prioritize deeper integration of its demand-side management (DSM) and distribution planning and operations systems so DSM resources can more easily be used to address local capacity constraints. They argue that using DSM at a more granular, location-specific level could help manage growing electrification impacts on the distribution system.

The Company agrees that DSM and demand response (DR) can play a role in addressing localized needs but emphasizes that these programs were originally designed for bulk-system reliability, not for dynamic, feeder-level distribution operations. While our current DR programs *can* be deployed for local distribution support, doing so requires days of advance notice to adjust program settings and dispatch protocols. By contrast, distribution conditions can change from hour to

hour, and effective real-time integration requires planning tools and operational systems that do not yet exist at scale.

To reliably use DSM and DR programs across the distribution system, the Company must complete the full DERMS deployment, including both Aggregator DERMS and Grid DERMS, and ensure these platforms can communicate seamlessly. This capability is still several years away. Additionally, building and operating these capabilities will require additional staff, technology investments, and appropriate cost recovery in future rate proceedings. Given these constraints, deeper DSM–distribution integration is a long-term goal aligned with DERMS implementation rather than a near-term IDP priority.

For these reasons, the Company does not support this recommendation.

## **IX. NON-WIRES ALTERNATIVES**

Stakeholders raised several concerns about the Company's NWA approach. Fresh Energy argues that the lack of Request for Information responses indicates the upcoming Request for Proposal (RFP) is unlikely to attract developers and recommends that the Company revise its approach if future solicitations continue to yield no interest. ELPC/VS/CEF note that NWAs have been manual and cost-intensive, suggesting that future DER-enabled tools—such as Capacity\*Connect or a DPP/VPP program—could better support distribution-level benefits. The Department recommends requiring the Company to include reliability projects in its NWA analysis.

The Company explains that its NWA approach reflects a balance of cost-effectiveness and customer risk and that many barriers—such as land availability and developer business models—are outside its control. NWAs are only appropriate when they meaningfully mitigate or defer traditional solutions; if they do not reduce risk, they should not be pursued.

The Company also notes that the DER-valuation issues raised by CEF/ELPC/VS are being addressed in the Capacity\*Connect docket<sup>6</sup> and encourages CEF/ELPC/VS to address its concerns there.

Finally, while we continue to evaluate NWA opportunities where they are appropriate, we do not support including urgent reliability projects in the NWA analysis cycle.

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<sup>6</sup> Docket No. E002/M-25-378

Reliability needs often arise suddenly—for example, when a cable fails multiple times in a short period—and must be addressed immediately to maintain safe and reliable service. Waiting for an NWA analysis, which occurs on a multi-year planning and budget cycle, would leave customers exposed to repeated outages and operational risk. In many of these cases, the likely NWA mitigation (such as a battery) would not eliminate the underlying reliability problem; the failing asset would still need to be replaced. Because the Company has an obligation to maintain service and cannot allow equipment to continue failing for years while awaiting NWA screening and implementation, these time-sensitive reliability projects must proceed outside the NWA process.

For these reasons, we do not believe additional Commission direction is required at this time.

## **X. REVIEW OF IDP FILING REQUIREMENTS**

The Department recommends that the Commission order the Executive Secretary to convene a work group to identify IDP filing requirements that the Company and intervenors agree can be removed.

The Company notes that this proposed effort appears to overlap, at least in part, with the ongoing work of the Distribution Data Reporting Workgroup, which is already examining opportunities to streamline and improve reporting requirements. To the extent an additional forum is needed to specifically address IDP filing requirements, the Company is open to participating in and working collaboratively with stakeholders to identify opportunities to reduce unnecessary or duplicative reporting.

## **XI. RECOMMENDATIONS OUTSIDE THE SCOPE OF THE IDP**

### **A. Service Quality Related Equity Considerations**

The Department also requests explanations for variations in outage duration across income groups and across communities with differing racial composition. These issues relate directly to service quality, reliability metrics, and disconnection practices, which are addressed in detail in the Company's annual reports on Safety, Reliability and Service Quality (SRSQ). In the 2023 SRSQ docket, two independent studies—by Pradhan and Chan and by TRC Companies—evaluated outage and disconnection data and identified higher rates of long outages (defined as interruptions of 12 hours or

more, CELI-12) in certain Census Block Groups.<sup>7</sup> In response, the Company's 2024 SRSQ Annual Report examined the drivers of these disparities, explaining that they were largely attributable to unusual weather events during the limited three-year study period. The Company also evaluated potential mitigation strategies—including targeted undergrounding, enhanced vegetation management, and pole replacement—and identified targeted undergrounding as the most effective option to reduce long outages.<sup>8</sup> In addition, the Company has engaged an independent third-party evaluator to conduct an in-depth review of capital investment planning, outage restoration practices, and shutoff policies to better understand observed service quality disparities.<sup>9</sup> That work is underway and will be reported in future SRSQ filings.

We share stakeholders' interest in advancing equity in utility planning and customer outcomes—but the IDP is not the appropriate forum to resolve questions about outage disparities or disconnection practices. These topics are already under active review in the annual SRSQ dockets, where the Company will continue to provide detailed analysis and identify potential next steps.

In short, we do not support this recommendation because they would duplicate ongoing efforts in our SRSQ dockets as well as other Commission-directed workgroups.

## **B. Geospatial Analysis**

The Department requests that the Company explain how a wide range of geospatial and demographic inputs—such as population estimates and growth trends, asset-health metrics, customer density and load composition, large customer concentrations, historical reliability indicators, and climate-related risk metrics—are incorporated into the Company's planning framework at the Planning Division level.

As a threshold matter, the Company emphasizes that distribution planning in the IDP is performed at the feeder-circuit and substation-transformer level, not at the broader Planning Division level. These units reflect how the system is actually designed and

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<sup>7</sup> Pradhan, Bhavin and Gabriel Chan. 2024. *Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area*. See <https://hdl.handle.net/11299/261434>. And Close, Brett. TRC Companies. *Service Quality and Demographics Analysis*. Filed with Xcel Energy's Service Quality Report 2023, Attachment Q, Docket No. E002/M-24-27.

<sup>8</sup> Northern States Power Company, doing business as Xcel Energy. 2024 ANNUAL REPORT: SAFETY, RELIABILITY AND SERVICE QUALITY PERFORMANCE AND PROPOSED RELIABILITY MEASURES. Part III: JANUARY 13, 2025 ORDER COMPLIANCE. Docket No. E002/M-25-27. April 1, 2025. See pages 116-124.

<sup>9</sup> January 13, 2025 ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS. *In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report*. Docket E-002/M-24-27. Order Point 46.

operated and provide the level of granularity needed to evaluate load growth, asset condition, hosting-capacity constraints, and localized reliability needs. While some results can be aggregated to the Planning Division level for high-level trend observation, such aggregation can mask important differences across individual feeders and substations and risks overgeneralizing conditions across large, diverse geographic areas.

The specific data types referenced by the Department—including asset-condition metrics, customer-density and load-composition information, and climate-risk indicators—are incorporated where appropriate within feeder- and substation-level analyses, where they can meaningfully inform evaluations of capacity constraints, asset-replacement needs, and localized reliability concerns. Population and demographic trends may inform broader forecasting work, but they are not applied at the Planning Division scale, which does not align with electrical system topology. Similarly, reliability metrics such as SAIDI, SAIFI, and chronic-outage locations are monitored at the circuit level, and related equity questions continue to be addressed in the Service Quality docket.

The IDP remains a feeder- and substation-based planning framework. Planning Division-level analysis is not the appropriate scale for reliability, capacity, or asset-health decision-making. Therefore, the Company does not support this request.

### **C. Capacity\*Connect**

The Department recommends that the Commission require the Company to prioritize distribution-system objectives in Capacity\*Connect dispatch, report on trade-offs when DERMS serves bulk-system needs over local needs, and develop a separate Distributed Power Plant/Virtual Power Plant (DPP/VPP) program.

These recommendations fall outside the scope of the IDP. Capacity\*Connect is already being developed—and its design, dispatch rules, and value-stacking considerations are being addressed—in its own dedicated docket, which is the appropriate venue for programmatic and tariff-based decisions. The IDP is not intended to modify customer-program design or mandate VPP constructs.

More broadly, Capacity\*Connect is a customer program and DER-aggregation mechanism. Any changes to dispatch priority, program rules, or new DPP/VPP offerings must be handled in the Capacity\*Connect docket, where operational, compensation, and customer-participation issues can be evaluated comprehensively.

Finally, the type of multi-objective dispatch envisioned by the Department requires full deployment of Aggregator DERMS and Grid DERMS, plus interoperability between them—capabilities that remain several years away and will require additional resources and cost recovery. Until those systems are in place, the Company cannot reliably optimize dispatch across both bulk-system and distribution-system needs.

The Company does not support addressing these issues in the IDP. They should continue to be developed in the Capacity\*Connect docket, where the relevant program-design and operational questions are already under active review.

#### **D. Proposed Dual-Fuel Load Control Pilot**

CEE recommends that the Company develop a dual-fuel load control pilot—pairing cold-climate heat pumps with gas backup and integrating controls through Aggregator DERMS—for the 2027–2028 heating season. They argue this approach can deliver most of the emissions benefits of electrification while helping manage emerging winter peaks and enabling targeted kW reductions.

The Company emphasizes its technology-neutral stance: we support customer choice and the beneficial electrification of homes and businesses while maintaining a focus on system reliability and affordability. While we agree that dual-fuel technologies may play a role in managing electrification impacts, the proposal to design and file a dual-fuel load control pilot is more appropriately addressed in the Company’s Energy Conservation and Optimization (ECO) Triennial Plan, where pilots, customer programs, and demand-side initiatives are developed and evaluated. The IDP is not the proper venue for these programmatic requests.

We also confirm that our system-planning processes already contemplate a gradual shift toward winter peaks, and this trajectory is reflected in the Company’s load-forecasting tools and DERMS roadmap. CEE’s comments underscore the importance of advancing these system-visibility and control capabilities—work that is already underway through our DERMS implementation efforts.

For these reasons, we do not believe that developing a dual-load control pilot is necessary as part of the IDP.

## **E. Aggregator DERMS Pilot Program**

The Department recommends that the Commission direct the Company to initiate a pilot program to test localized distribution grid benefits from its Aggregator DERMS, including testing incentive levels, multiple controllable load types, and conducting a cost-benefit analysis relative to traditional distribution upgrades.

The Company does not believe this recommendation is appropriately addressed in the IDP. The IDP is an informational planning filing focused on distribution system needs, planning standards, and anticipated investments—not the design or implementation of customer incentive programs or DER pilot structures. Issues related to incentive design, participation levels, and program-specific cost-benefit analyses are more appropriately considered within the Company’s existing energy efficiency and demand response regulatory framework.

Accordingly, any consideration of an Aggregator DERMS pilot program should occur in the Company’s ECO Triennial Plan, where pilots, customer programs, and demand-side initiatives are developed and evaluated.

## **F. Minneapolis-Specific Planning Scenario**

The City of Minneapolis recommends that the Company incorporate a “Minneapolis electrification scenario” into future planning to reflect several city-specific initiatives. These include significant City-led efficiency and electrification investments underway since 2023, findings from its Thermal Energy Network potential study identifying areas with high electrification potential, and Clean Energy Partnership efforts that could accelerate concentrated electrification and efficiency deployments.

While we appreciate the City of Minneapolis’ interest in aligning local planning with our broader distribution-planning processes, we cannot incorporate a Minneapolis-specific scenario into the IDP. The IDP must remain service-area-wide and jurisdiction-neutral. Modeling unique city-level assumptions would introduce unverifiable load forecasts, create planning inconsistencies, and raise equity concerns across other municipalities.

As a constructive next step, we recommend that the City of Minneapolis engage in the Company’s Proactive Distribution Grid Upgrades (PDGU) Framework stakeholder process.<sup>10</sup> This forum offers a structured venue for cities to explore electrification

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<sup>10</sup> Docket No. E002/CI-24-318

impacts, share local planning insights, and better understand how utility tools evaluate concentrated load growth. Participation would also allow the City to bring forward the results of its Thermal Energy Network study and related electrification initiatives in a format that can be compared with system needs across the broader service area. In addition, the PDGU Framework is designed to identify potential distribution constraints early and consider whether targeted upgrades or non-traditional solutions are appropriate. Engagement through this forum would therefore enable the City of Minneapolis to help shape how localized municipal planning efforts—such as electrification or energy-efficiency initiatives—could appropriately inform broader system planning without compromising the service-area-wide, jurisdiction-neutral requirements of the IDP.

### **G. Proactive Capacity Investments**

The Department recommends that the Commission convene a working group to update the Distribution System Reactive Upgrades Process (DSRUP) for load, and further suggests that future Proactive Upgrade Proposals include an integrated alternatives analysis incorporating FI, DSRUP, NWA, mobile BESS, Capacity\*Connect, and planning-standard variances.

The Company does not believe such a working group or expanded alternatives-analysis requirement is necessary. Unlike DER interconnections, the cost of distribution upgrades is typically not a barrier for new or expanding load due to the Company's Contribution in Aid of Construction (CIAC) policies. These revenue-justification policies provide load customers with a credit equal to 3.5 times their expected annual revenue, which means that in some cases, load customers pay little—if anything—for necessary system upgrades. Because load-driven upgrades are already fully accommodated under this existing policy, there is no need for a separate load-focused DSRUP update or additional analysis requirements.

Furthermore, the suggested alternatives—such as FI, NWA, or mobile BESS—are generally tools intended to avoid or defer upgrades needed to mitigate DER-driven constraints. They are not typically appropriate or cost-effective substitutes for upgrades needed to serve new or growing load, which must be met promptly to ensure safe and reliable service. The Company's existing planning processes already incorporate least-cost, reliability-driven decision-making and ensure that required capacity investments are made in a timely and efficient manner.

Because CIAC policies already remove cost barriers for load customers and because load-driven upgrades must be completed to fulfill our service obligations, the Company does not support opening a working group or expanding proactive-upgrade alternatives analyses for load-related needs.

## CERTIFICATE OF SERVICE

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

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

xx electronic filing

**DOCKET No. E002/M-25-142**

Dated this 19<sup>th</sup> day of March 2026

/s/

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Victor Barreiro  
Regulatory Administrator

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59	Cheryl	Dietrich	cheryl.dietrich@nexteraenergy.com	NextEra Energy Resources, LLC		700 Universe Blvd E1W/JB Juno Beach FL, 33408 United States	Electronic Service		No	M-25-142
60	Diane	Dietz	diane.dietz@state.mn.us		Department of Commerce	Suite 280 85 Seventh Place East St. Paul MN, 55101-2198 United States	Electronic Service		No	M-25-142
61	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
62	Kristin	Dolan	kdolan@meeker.coop	Meeker Cooperative Light & Power Assn		1725 US Hwy 12 E. Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
63	Renee	Doyle	guydoyleelectric@gmail.com	Doyle Electric Inc.		PO Box 295 Amboy MN, 56010 United States	Electronic Service		No	M-25-142
64	Carlton	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate		75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul MN, 55155 United States	Electronic Service		No	M-25-142
65	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	M-25-142
66	Scott	Dunbar	sdunbar@kfwlaw.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-142
67	John R.	Dunlop, P.E.	jdunlop@resminn.com	Renewable Energy Services		Suite 300 448 Morgan Ave. S. Minneapolis MN, 55405-2030 United States	Electronic Service		No	M-25-142
68	Hannah	Dunn	hannah.dunn@oakdalemn.gov	City of Oakdale		1584 Hadley Ave N Oakdale MN, 55104 United States	Electronic Service		No	M-25-142
69	Kelly	Dybdahl	kdybdahl@llec.coop	Lyon-Lincoln Electric Cooperative, Inc.		205 W. Hwy. 14 Tyler MN, 56178 United States	Electronic Service		No	M-25-142
70	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
71	Dick	Edwards	dedwards@ci.maple-grove.mn.us	City of Maple Grove		12800 Arbor Lakes Parkway	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						P O Box 1180 Maple Grove MN, 55311- 6180 United States				
72	William	Ehrlich	wehrlich@tesla.com	Tesla, Inc.		3500 Deer Creek Rd Palo Alto CA, 94304 United States	Electronic Service		No	M-25- 142
73	Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE		28477 N Lake Ave Frontenac MN, 55026- 1044 United States	Electronic Service		No	M-25- 142
74	Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte		100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul MN, 55155 United States	Electronic Service		No	M-25- 142
75	R. Neal	Elliot	rnelliott@aceee.org	American Council for an Energy-Efficient Economy		ACEEE 529 14th St NW Ste 600 Washington DC, 20045 United States	Electronic Service		No	M-25- 142
76	Nadav	Enbar	nenbar@epri.com	EPRI		1117 Quince Ave Boulder CO, 80304 United States	Electronic Service		No	M-25- 142
77	John	Farrell	jfarrell@ilsr.org	Institute for Local Self- Reliance		2720 E. 22nd St Institute for Local Self- Reliance Minneapolis MN, 55406 United States	Electronic Service		No	M-25- 142
78	Christian	Fenstermacher	christian.fenstermacher@owatonnautilities.com	Owatonna Municipal Public Utilities		PO Box 800 208 S Walnut Ave Owatonna MN, 55060 United States	Electronic Service		No	M-25- 142
79	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101- 2198 United States	Electronic Service		No	M-25- 142
80	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	M-25- 142
81	Kornbaum	Frank	fkornbaum@mnpower.com			null null, null United States	Electronic Service		No	M-25- 142
82	Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	M-25- 142
83	David	Freestate	dfreestate@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25- 142
84	Katelyn	Frye	kfrye@mnpower.com	Minnesota Power		30 W Superiot St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25- 142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
85	Jessica	Fyhrie	jfyhrie@otpc.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
86	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
87	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
88	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-142
89	Sean	Gosiewski	sean@afors.org	Alliance for Sustainability		2801 21st Ave S Ste 100 Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
90	Scott	Greenbert	scott@nautilusolar.com	Nautilus Solar Energy, LLC		396 Springfield Ave, Ste 2 Summit NJ, 07901 United States	Electronic Service		No	M-25-142
91	Sarah	Groebner	sgroebner@redwoodelectric.com	Redwood Electric Cooperative		60 Pine St Clements MN, 56224 United States	Electronic Service		No	M-25-142
92	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	M-25-142
93	Cody	Gustafson	cgustafson@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
94	Tom	Guttormson	tom.guttormson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd Ramsey MN, 55303 United States	Electronic Service		No	M-25-142
95	Natalie	Haberman	townsend@fresh-energy.org	Fresh Energy		408 St Peter St # 350 St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
96	Nicholas	Haeg	haeg@fresh-energy.org			12298 Bass Trail Sauk Centre MN, 56378 United States	Electronic Service		No	M-25-142
97	James	Haler	jhaler@southcentralelectric.com	South Central Electric Association		71176 Tiell Dr P. O. Box 150 St. James MN, 56081 United States	Electronic Service		No	M-25-142
98	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-142
99	Donald	Hanson	dfhanson@ieee.org			P. O. Box 44579 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-142
100	John	Harlander	john.c.harlander@xcelenergy.com	Xcel Energy		null null, null	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						United States				
101	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
102	Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.		701 E. Cary Street Richmond VA, 23219 United States	Electronic Service		No	M-25-142
103	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
104	Tiana	Heger	theger@mnpower.com	Minnesota Power		30 W. Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
105	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	M-25-142
106	Annete	Henkel	mui@mutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	M-25-142
107	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
108	Mari	Hernandez	mari@irecusa.org	IREC		null null, null United States	Electronic Service		No	M-25-142
109	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	M-25-142
110	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	M-25-142
111	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	M-25-142
112	Casey	Horan	choran@edf.org	Environmental Defense Fund		123 Mission St San Francisco CA, 94105 United States	Electronic Service		No	M-25-142
113	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	M-25-142
114	Frank	Hornstein	frank.hornstein@minneapolismn.gov	City of Minneapolis		350 South 5th Street Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
115	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						DC, 20006 United States				
116	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
117	Jan	Hubbard	jan.hubbard@comcast.net			7730 Mississippi Lane Brooklyn Park MN, 55444 United States	Electronic Service		No	M-25-142
118	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-142
119	Reuben	Hunter	bhunter@madisonei.com	Madison Energy Investments		8100 Boone Blvd Suite 430 Vienna VA, 22182 United States	Electronic Service		No	M-25-142
120	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	M-25-142
121	John S.	Jaffray	jjaffray@jirpower.com	JJR Power		350 Highway 7 Suite 236 Excelsior MN, 55331 United States	Electronic Service		No	M-25-142
122	Robert	Jagusch	rjagusch@mmua.org	MMUA		3025 Harbor Lane N Minneapolis MN, 55447 United States	Electronic Service		No	M-25-142
123	Chris	Jarosch	chris@carrcreekelectricservice.com	Carr Creek Electric Service, LLC		209 Sommers Street North Hudson WI, 54016 United States	Electronic Service		No	M-25-142
124	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	M-25-142
125	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
126	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
127	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD, 57042 United States	Electronic Service		No	M-25-142
128	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	M-25-142
129	Julie	Jorgensen	julie@greenmark.us.com	Greenmark Solar		4630 Quebec Ave N New Hope MN, 55428-4973 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
130	Kevin	Joyce	kjoyce@tesla.com			null null, null United States	Electronic Service		No	M-25-142
131	Mahmoud	Kabalan	mahmoud.kabalan@stthomas.edu	University of St Thomas		2115 Summit Ave. Mail OSS100 School of Engineering Saint Paul MN, 55105 United States	Electronic Service		No	M-25-142
132	Camille	Kadoch	ckadoch@raponline.org	Regulatory Assistance Project		50 State Street Suite 3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-142
133	Cliff	Kaehler	cliff.kaehler@novelenergy.biz	Novel Energy Solutions LLC		4710 Blaylock Way Inver Grove Heights MN, 55076 United States	Electronic Service		No	M-25-142
134	Ralph	Kaehler	ralph.kaehler@gmail.com			13700 Co. Rd. 9 Eyota MN, 55934 United States	Electronic Service		No	M-25-142
135	Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC		260 Salem Church Road Sunfish Lake MN, 55118 United States	Electronic Service		No	M-25-142
136	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	M-25-142
137	Jack	Kegel	jkegel@mmua.org	MMUA		3025 Harbor Lane N Suite 400 Plymouth MN, 55447-5142 United States	Electronic Service		No	M-25-142
138	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	M-25-142
139	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
140	Tom	Key	tkey@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
141	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
142	Jack	Kluempke	jack.kluempke@state.mn.us		Department of Commerce	85 7th Place East Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
143	Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP		222 South Ninth Street Suite 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
144	Steve	Kosbab	skosbab@meeker.coop	Meeker Cooperative Light and Power		1725 US Hwy 12 E Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
145	Nathan	Kostiuk	nathan.c.kostiuk@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-07 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
146	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	M-25-142
147	Michael	Krause	michaelkrause61@yahoo.com			1200 Plymouth Avenue Minneapolis MN, 55411 United States	Electronic Service		No	M-25-142
148	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
149	Corrina	Kumpe	ckumpe@mysunshare.com			null null, null United States	Electronic Service		No	M-25-142
150	Matthew	Lacey	mlacey@greenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-142
151	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
152	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
153	Burnell	Lauer	blauer.sundial@gmail.com	Sundial Solar		3209 W. 76th St #305 Edina MN, 55435 United States	Electronic Service		No	M-25-142
154	Dean	Leischow	dean@sunriseng.com	Sunrise Energy Ventures		315 Manitoba Ave Ste 200 Wayzata MN, 55391 United States	Electronic Service		No	M-25-142
155	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
156	Benjamin	Levine	blevine@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
157	Becky	Li	bli@rmi.org			17 State St 25th floor unit 2500 New York NY, 10004 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
158	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-142
159	Carl	Linville	clinville@raponline.org			50 State Street Suite #3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-142
160	Phillip	Lipetsky	greenenergyproductsllc@gmail.com	Green Energy Products		PO Box 108 Springfield MN, 56087 United States	Electronic Service		No	M-25-142
161	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-142
162	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
163	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	M-25-142
164	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
165	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-142
166	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
167	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
168	Kavita	Maini	kmairi@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	M-25-142
169	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
170	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
171	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		Yes	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
172	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	M-25-142
173	Jason	Maur	jason.maur@renesolapower.com	Renosola Power Holdings, LLC		850 Canal Street 3rd Floor Stamford CT, 06902 United States	Electronic Service		No	M-25-142
174	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
175	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
176	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	M-25-142
177	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	M-25-142
178	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
179	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	M-25-142
180	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	M-25-142
181	Tim	Mergen	tmergen@meecker.coop	Meecker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
182	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
183	Brian	Millberg	fwengineering@comcast.net			695 Grand Ave #222 Saint Paul MN, 55105 United States	Electronic Service		No	M-25-142
184	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
185	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142
186	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapolis MN, 55406 United States				
187	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25- 142
188	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	M-25- 142
189	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25- 142
190	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25- 142
191	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25- 142
192	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	M-25- 142
193	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	M-25- 142
194	Anthony	Nelson	amnelson@otpc.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	M-25- 142
195	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	M-25- 142
196	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	M-25- 142
197	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	M-25- 142
198	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25- 142
199	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy		426 17th Street, Suite 700 Oakland CA, 94612 United States	Electronic Service		No	M-25- 142
200	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25- 142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
201	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	M-25-142
202	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	M-25-142
203	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	M-25-142
204	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	M-25-142
205	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-142
206	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	M-25-142
207	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticello MN, 55362 United States	Electronic Service		No	M-25-142
208	Matthew	Olsen	molsen@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
209	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	M-25-142
210	Wendi	Olson	wolson@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
211	Carol A.	Overland	overland@legalelectric.org	Legalelectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	M-25-142
212	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
213	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
214	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	M-25-142
215	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
216	Dean	Pawlowski	dpawlowski@otpc.com	Otter Tail Power Company		PO Box 496 215 S. Cascade St. Fergus Falls MN, 56537-0496 United States	Electronic Service		No	M-25-142
217	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
218	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	M-25-142
219	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
220	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	M-25-142
221	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
222	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	M-25-142
223	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	M-25-142
224	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	M-25-142
225	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	M-25-142
226	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	M-25-142
227	Kevin	Pranis	kpranis@liunagro.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	M-25-142
228	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
229	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	M-25-142
230	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	M-25-142
231	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	M-25-142
232	Generic Notice	Regulatory	regulatory_filing_coordinators@otpc.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
233	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	M-25-142
234	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-142
235	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	M-25-142
236	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
237	Michael	Riewer	mriewer@otpc.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
238	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142
239	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	M-25-142
240	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	M-25-142
241	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
242	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
243	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55901 United States				
244	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
245	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
246	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	M-25-142
247	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	M-25-142
248	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	M-25-142
249	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
250	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	M-25-142
251	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
252	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-142
253	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington MN, 55024 United States	Electronic Service		No	M-25-142
254	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	M-25-142
255	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-142
256	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
257	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
258	Rob	Scott Hovland	rob.scott-hovland@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
259	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	M-25-142
260	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	M-25-142
261	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	M-25-142
262	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	M-25-142
263	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
264	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
265	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
266	Felicia	Skaggs	fskaggs@meecker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
267	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	M-25-142
268	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	M-25-142
269	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	M-25-142
270	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
271	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
272	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	M-25-142
273	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	M-25-142
274	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
275	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	M-25-142
276	Karl	Sonneman	karl17@hbci.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	M-25-142
277	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
278	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-142
279	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
280	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
281	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
282	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	M-25-142
283	Cary	Stephenson	cstephenson@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
284	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
285	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-142
286	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	M-25-142
287	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	M-25-142
288	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	M-25-142
289	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	M-25-142
290	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	M-25-142
291	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
292	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	M-25-142
293	Stuart	Tommerdahl	stommerdahl@otpc.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
294	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
295	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
296	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	M-25-142
297	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	M-25-142
298	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
299	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-142
300	Adam	Tromblay	atromblay@noblesce.com	Nobles Cooperative Electric		P.O. Box 58 Slayton MN, 56127-0058 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
301	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
302	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
303	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	M-25-142
304	Gary	Van Winkle	gvanwinkle@mylegalaid.org	Mid-Minnesota Legal Aid		111 N Fifth St Ste 100 Minneapolis MN, 55403 United States	Electronic Service		No	M-25-142
305	John	Vaughn	nik@rreal.org	Rural Renewable Energy Alliance		3963 8th Street SW Backus MN, 55435 United States	Electronic Service		No	M-25-142
306	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	M-25-142
307	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	M-25-142
308	Curt	Volkman	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
309	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	M-25-142
310	Robert J.V.	Vose	rvose@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
311	Stacy	Wahlund	swahlund@otpc.com	Otter Tail Power Company		215 S. Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
312	Sarah	Walinga	swalinga@solarcity.com	Energy Freedom Coalition		3055 Clearview Way San Mateo MN, 94402 United States	Electronic Service		No	M-25-142
313	Kevin	Walker	kwalker@beaconinterfaith.org	Beacon Interfaith Housing Collaborative		null null, null United States	Electronic Service		No	M-25-142
314	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	M-25-142
315	Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
316	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	M-25-142
317	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	M-25-142
318	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
319	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	M-25-142
320	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-142
321	John	Williamson	john.williamson@state.mn.us	Minnesota Department of Labor and Industry		443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-142
322	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	M-25-142
323	Danielle	Winner	danielle.winner@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
324	Heidi	Winter	hwinter@co.murray.mn.us	Murray County		2500 28th Street PO Box 57 Slayton MN, 56172 United States	Electronic Service		No	M-25-142
325	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	M-25-142
326	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
327	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	M-25-142
328	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						8920 United States				
329	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188- 1022 United States	Electronic Service		No	M-25- 142
330	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	M-25- 142
331	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	M-25- 142
332	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25- 142