414 Nicollet Mall
Minneapolis, MN 55401

May 8, 2025

—Via Electronic Filing—

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

RE: COMMENTS
PROACTIVE DISTRIBUTION UPGRADES AND COST ALLOCATION
DOCKET NO. E002/CI-24-318

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments in response to the April 7, 2025 Notice of Comment Period in the above-referenced docket.

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 or me at brian.t.monson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON
MANAGER, DISTRIBUTION REGULATORY STRATEGY

Enclosures
cc: Service List

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 A COMMISSION INQUIRY INTO A FRAMEWORK FOR PROACTIVE DISTRIBUTION GRID UPGRADES AND COST ALLOCATION FOR XCEL ENERGY	DOCKET NO. E002/CI-24-318 **COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits these Comments to the Minnesota Public Utilities Commission in response to the April 7, 2025 Notice of Comment Period in the above-referenced docket. This Notice follows the conclusion of a Commission-led stakeholder workgroup process that was an outcome of the Commission's September 16, 2024 Order on the Company's 2023 Integrated Distribution Plan.[1]

The Commission-led workgroup process to develop the Proactive Distribution Grid Upgrades (PDGU) framework began in November 2024 and concluded in March 2025. The PDGU workgroup process resulted in a draft Framework that defines proactive upgrades, establishes the process for utilities to propose these upgrades for consideration and approval by the Commission, and establishes a cost allocation and recovery methodology for approved projects.

We appreciate the collaborative approach the Commission undertook to develop this Framework. We believe a constructive framework for Proactive Distribution Grid Upgrades can serve to streamline the review and approval of investments that are necessary to prepare the distribution grid for increased customer loads and growth in Distributed Energy Resources (DER) adoption. For the Framework to be constructive, it needs to:

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[1] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, ORDER (September 16, 2024).

- Be flexible and clear, and avoid being overly prescriptive;
- Provide utilities a clear path to recover costs for approved projects and the ability to earn on its investments,
- Follow established cost recovery concepts and mechanisms, and
- Serve to streamline the review and approval of proactive distribution grid upgrades.

We appreciate the opportunity to work with stakeholders to develop a proposed framework for Proactive Distribution Grid Upgrades and provide our comments below.

COMMENTS

I. Should the Commission establish a framework for Proactive Distribution Grid Upgrades for Xcel Energy?

Yes. A framework for proactive distribution system upgrades can serve to streamline the review and approval of these investments. We view these investments as important to prepare the electric grid for increased customer loads and DER adoption. We offer several key reasons why a Framework to guide these investments is helpful:

1. *Streamline Review of Projects:* Implementing a streamlined framework for the review and approval of these upgrades reduces the burden on both the Company and the Commission, providing a solid foundation for cost recovery for previously-approved projects.

2. *Reduce Reactive Upgrades*: The forecasted rate of adoption of DER and customer load growth presents an unprecedented challenge for the distribution system over the next 30 years, as discussed in our most recent Integrated Distribution Plan. Forecasts in our 2023 IDP showed that our aggregated feeder peak demand will triple during this period.[2] If we limit our investments and continue to upgrade the system reactively, customers may face lengthy lead times while waiting for the Company to complete system upgrades before their loads can be served or they can implement DER.

[2] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Docket No. E002/M-23-452, 2023 INTEGRATED DISTRIBUTION PLAN AT 2-3 (November 1, 2023).

3. *Reduce Persistent Capacity Constraints*: An effective and streamlined framework for proactive upgrades, if properly structured, may help reduce capacity constraints for DER. Today, constraints affect hosting capacity for DER on certain portions of the distribution system.

4. *Meet Future Load Forecasts*: We are forecasting significantly increased loads on our distribution system, as our customers electrify their end uses, and new types of load such as crypto mining, data centers, etc. emerge. A Commission-approved Framework that establishes criteria to stay ahead of these needs will help guide the Company's planning and implementation.

II. Which requirements from the Draft Proactive Distribution Upgrade Framework, as outlined in Attachment A, should the Commission adopt?

Please refer to Attachment 3 to these comments, which contains a matrix that details the Company's perspective on specific requirements from Notice Attachment A, along with our reasoning for any requirements we oppose. Additionally, Attachment 1 provides our preferred framework. Below, we briefly summarize our three highest-priority recommendations:

1. *Flexibility:* The Proactive Upgrades Framework must be flexible and easy to navigate and understand – and start out as simple as possible, as this is an entirely new process. It is important to avoid overly prescriptive requirements at the outset until the Commission, utilities, and stakeholders have gained experience with the process. Further, overly prescriptive requirements may have unintended consequences, such as making it difficult for certain upgrades to qualify that would otherwise achieve the Commission's policy objectives. Additionally, such requirements may create long implementation periods that delay customers' ability to increase load and adopt DER. Finally, overly-prescriptive requirements would lead to a framework that is difficult to understand and onerous for the Company, the Commission, and stakeholders to navigate. The Company emphasizes starting with a framework that is simple and clear and then adapt the framework as all parties gain experience and areas of refinement become clear.

2. *Cost Recovery:* We emphasize that the Framework must provide the Company a clear path to cost recovery and the ability for it to earn a return on its investments for it to pursue these investments. There needs to be a single process that evaluates proposed projects and leads to a Commission decision to approve, deny, or modify the project – providing the Company with certainty that it will be able to recover its prudently-incurred costs, should it choose to

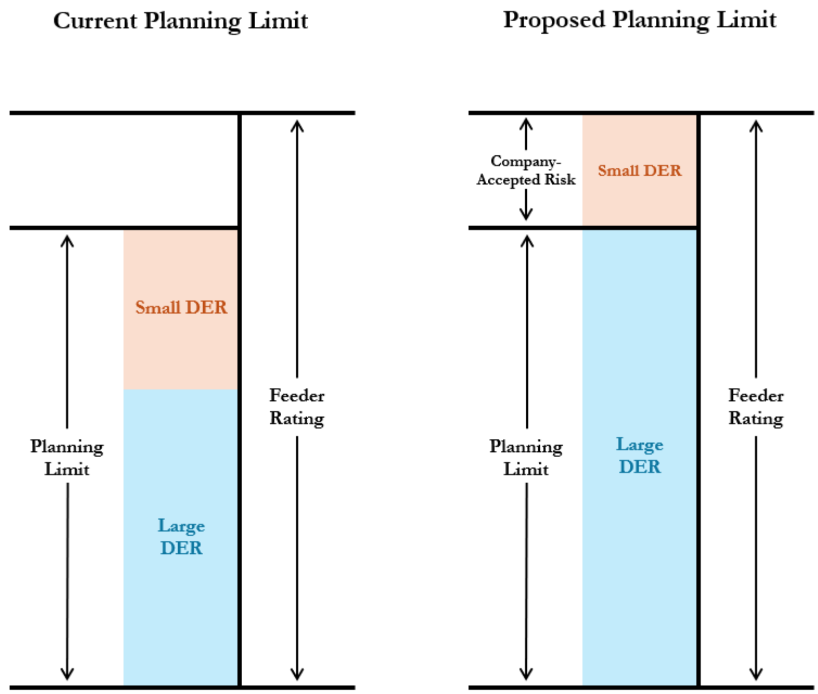
proceed with the proactive investment. By their nature, the proactive investments contemplated by this Framework are more speculative than those stemming from traditional planning processes. Consequently, there is a risk that the anticipated customer loads or DER projected at the time of a project's proposal and approval may not materialize as expected. If that occurs, the cost recovery mechanism for these investments must ensure that the utility does not bear risk from hindsight, when the project proposal resulted from a process where stakeholders weighed in and the Commission approved the project.

3. *Capacity Reservations for Small DER:* We recommend the Commission adopt our proposed capacity reservation for small DER to allow residential customers to more directly participate in the clean energy transition. Detailed in sections L.4 and L.4A of the draft framework, our proposed capacity reservation would adjust the way we plan for DER, which is currently known as the Technical Planning Standard.[3] This modification allows Priority Queue distributed generation (DG) to exceed the planning limit, but not the feeder thermal rating, as an accepted risk for the distribution system.

   Exceeding the planning limit, even temporarily, presents risk to the broader distribution system and must be managed carefully. However, this risk is acceptable for Priority Queue DG because these DG resources are smaller and associated with localized load, which helps mitigate some of the impacts on the distribution system. Additionally, exceeding the planning limit for DER would be a temporary condition, as the Reactive DER Cost Sharing and this PDGU framework create viable paths to upgrade the system back within the planning limit. Figure 1 below shows a visual comparison of our current and proposed planning limit.

[3] The Technical Planning Standard is defined as 80 percent of the continuous rating plus daytime minimum load.

Figure 1:
Planning Limit Comparison



Our proposed capacity reservation offers several benefits:

- *Support for Small DER:* This would provide capacity for small DER to interconnect in areas where larger DER developers, such as Community Solar Gardens (CSGs), are active and have consumed the currently available capacity. This helps ensure that our smaller, particularly residential, customers can install rooftop solar without triggering costly upgrades.
- *Streamlined Processing:* Our proposed capacity reservation allows more streamlined processing of small DER applications through the recently implemented Priority Queue. The Company prioritizes DER applications in the Priority Queue over those in the General Queue. Once a feeder's planning limit is reached, the proposed capacity reservation would enable continued interconnection of small DER applications.
- *Facilitating Larger DER Projects:* With small DER applications continuing to move forward after the planning limit is reached, larger DER applications in the General Queue could proceed with System Impact Studies, pursue a cluster study, or DER cost sharing (through the future Reactive cost sharing framework), which small DER applications

typically cannot afford.

Without our proposed capacity reservation, customers may face long lead times to connect small DER in areas with CSGs, as these gardens may consume all available capacity. Additionally, the utility can perform cluster studies more effectively and make DER interconnection more viable through the future DER cost sharing framework.

III. Does the Draft Framework address the following topics from the Commission's September 16, 2024 Order in Docket No. E002/CI-24-318?

a. How to allocate the costs of proactive upgrades.

b. How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.

c. If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.

d. How a proactive upgrade program would integrate with a utility's planned distribution investment programs.

e. How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.

f. How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.

g. Whether there should be changes to any of a utility's service policy provisions such as Contributions in Aid of Construction (CIAC).

We believe the Draft Framework addresses all these sections, which we outline in Table 1 below.

Table 1
Order Topics in Relation to Framework Sections

Topic	Section in Draft Framework
How to allocate the costs of proactive upgrades.	Section K – Cost Allocation
How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.	Section F – Potential Sites for Proactive Upgrades Section G – Proactive Upgrade Proposal Evaluation Criteria Section K – Cost Allocation
If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.	Section L – Capacity Reservation
How a proactive upgrade program would integrate with a utility's planned distribution investment programs.	Section C – Process Section H – Proposal for Non-Location Specific Proactive Measures
How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.	Section K – Cost Allocation Section L – Capacity Reservation
How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.	Section C – Process Section E – Forecast
Whether there should be changes to any of a utility's service policy provisions such as Contributions in Aid of Construction (CIAC).	Section K – Cost Allocation Section L – Capacity Reservation

IV. Should the Commission establish Phase 2 of the Proactive Distribution Grid Upgrade Proceeding as proposed in Attachment B, and if so, what should the scope and timeline be?

Please refer to Attachment 3 to these comments, which contains a matrix detailing the specific sections from Notice Attachment B that we recommend the Commission adopt, along with our reasoning for any requirements we oppose. Additionally, Attachment 2 provides our preferred Phase 2 proposal.

Below, we briefly summarize our highest-priority recommendations regarding the scope of Phase 2.

1. *Forecasting Front of the Meter DER:* We recommend further developing requirements and processes for gathering input from the DER developer community and other stakeholders. This input could help identify areas with higher and lower probabilities of front-of-the-meter (FTM) DER adoption. Phase 2 was originally aimed to address the complex considerations around forecasting large FTM DER developments, such as CSGs. FTM DER is difficult to forecast accurately due to the large capacity requirement for individual CSGs compared to the hosting capacity of an overall feeder or substation. Forecast inaccuracies can significantly impact the need for upgrades in an area. While developable land can be identified in the forecast model, it does not necessarily indicate the likelihood of DER developers pursuing a facility at a specific location.

2. *Capacity Reservation for Small DER:* The Company supports adopting the proposed system-wide capacity reservation in Phase 1 but recommends considering it in Phase 2 if not initially adopted. Our proposed capacity reservation, detailed in sections L.4 and L.4.A of the framework, would adjust our planning limit for DER and is also described above in response to Question II.

3. *Exclusion of Certain Topics:* The Company does not support including reactive projects, flexible interconnection, or advanced cost allocation and cost recovery as Phase 2 topics.

    a. <u>Reactive Projects</u>: We do not support including any reactive projects in this Framework, which is intended for proactive upgrades. Indeed, reactive projects are in direct conflict with the Commission's Notice that defines proactive distribution upgrades as "a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle."

    b. <u>Flexible Interconnection</u>: We do not support including flexible interconnection in this framework because it is not an upgrade; rather, it is a way of avoiding some level of upgrades. Additionally, flexible interconnection is not currently available for DER interconnections in Minnesota under the Commission-established Minnesota Distributed Energy Resources Interconnection Process (MN DIP).

    c. <u>Advanced Cost Allocation</u>: In the workgroup process, a concept called "advanced cost allocation" was raised for consideration. This is not an established regulatory construct or mechanism. There is no reason why cost allocation for proactive distribution upgrades would need to be done differently from other utility investments that are recovered from various customer classes or through participant fees. Additionally, the rate case class cost allocation process and revenue apportionment already provides an appropriate venue to holistically consider cost allocation.

Regarding the timeline for Phase 2, the Company believes Phase 2 development should allow sufficient time for an iterative, collaborative process similar to Phase 1. This process should begin immediately following the 2025 IDP and conclude with enough time to incorporate framework changes into the Company's Proactive Distribution Upgrades Proposal in its 2027 IDP. The Company supports setting a goal date for a Commission decision on the Phase 2 framework before the end of Q4, 2026.

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

No. The Company does not believe there are any other issues or concerns to address at this time.

CONCLUSION

The Company appreciates the opportunity to comment on the proposed Proactive Distribution Grid Upgrades Framework. We look forward to continuing to collaborate with the Commission and stakeholders to develop this Framework.

Dated: May 8, 2025

Northern States Power Company

Xcel Energy Preferred Proactive Distribution Upgrade Framework

A. Introduction

The Commission establishes the following framework for proactive distribution upgrades for [utility] to achieve the following goals:

A.2 Proactively plan for the distribution system upgrades necessary to ~~meet state energy policy requirements and goals~~ enable customer DER and electrification adoption, considering state energy policy requirements and goals.

A.3 Meet customer expectations by reducing or eliminating the wait time to interconnect DERs and new load to the extent reasonably possible.

A.5 Protect ratepayers by establishing a ~~rigorous~~ review of proposed proactive investments to ~~ensure they do not cause undue risk costs or~~ minimize the risk of stranded assets or projects that result in inequitable distribution of costs or benefits.

A.7 To the extent reasonably possible, maximize the benefits to the distribution system while minimizing the costs.

A.9 Limit cost impacts from unreasonable forecast inaccuracies.

The Commission establishes the following principles to guide allocation of the costs of proactive upgrades:

A.10 Limit deviations from traditional cost allocation and recovery processes to the extent possible.

A.11 Costs should be allocated to the customers or classes causing the costs, when appropriate.

B. Definitions

The Commission adopts the following definitions for the purposes of this framework:

B.2 Cost-Share Customer: a customer who applies to interconnect either load or generation at a location served by a Proactive Distribution Upgrade with an open cost-share window and is responsible for paying a Cost-Share Fee, unless otherwise specified in approved tariffs.

B.3 Cost-Share Fee: the amount a Cost-Share Customer pays to access a location served by a Proactive Distribution Upgrade.

B.4 Cost-Share Window: the period during which Cost-Share Fees are collected from Cost-Share Customers.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue.

B.5 Distribution Capacity Upgrade: A distribution system upgrade at the substation or feeder level that increases hosting capacity for load and/or generation on the distribution system.

B.6 Distributed Energy Resource (DER): Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.

B.8 Distributed Generation (DG): a generation facility that ~~has a capacity of 10 MW or less,~~ is interconnected with a utility's distribution system~~,~~ and operates in parallel with the utility~~, and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures~~.

B.9 Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes.

B.10 Forecasted/Proactive Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under forecasted system conditions.

B.11 Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under existing system conditions.

B.12 Integrated Distribution Plan: the biennial report established in Docket E002/CI-18-251 and as currently outlined in the filing requirements available [here].

B.13 Priority Queue: The queue for "customer-sited" Interconnection Applications up to 40 kWac and applications that are a part of the Solar for Schools or Solar on Public Buildings legislative programs that comply with the 120% rule, as detailed on tariff sheet 10-81.5.

B.15 Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework. In the context of this framework, the Proactive Distribution Upgrades submitted in the Proactive Upgrade Proposal would not be considered prudent under existing distribution planning practices due to the proactive nature of the projects.

B.16 Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle.

B.17 Small DER Cost Sharing Fund: [Utility's] cost sharing fund for MN DIP applications of $40kW_{ac}$ or less as detailed on [tariff sheet 10-81.4].

C. Process

C.1 [Utility] may file a Proactive Upgrade Proposal in conjunction with its Integrated Distribution Plan (IDP) due on November 1 of odd numbered years. The Proactive Upgrade Proposal shall be evaluated through the same docket and process as the IDP but is not part of the IDP.

C.2 The Proactive Upgrade Proposal may include proactive distribution upgrades that have not been initiated and shall begin construction within five years from the date of the filing. It may also contain proactive distribution upgrades that are not specific to a single location but shall upgrade the same type of asset(s) across multiple locations.

C.3 The Proactive Upgrade Proposal must demonstrate alignment with the framework, and the Commission shall review and approve, deny, or modify the Proposal with a goal of completion within 12 months from the date of the initial filing.

C.4 [Utility] is not obligated to initiate a project if it is approved in the Proactive Upgrade Proposal. If [utility] does not proceed with an approved project, it shall explain why and the impact on the overall program budget with its Annual Report, as described in L. Reporting - 9 below.

C.5 Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes would be considered scope changes to the project that would substantially impact overall project cost.

C.8 As addressed further in Section J: Cost Recovery, the Utility must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.

C.9 The Proactive Upgrade Framework is subject to refinement through the Proactive Grid Upgrade Workgroup. The Proactive Grid Upgrade Workgroup shall be convened by Commission Staff and shall meet as necessary to refine and improve the Proactive Upgrade Framework. This shall include Phase 2 of the framework development in 2025 and 2026 to ~~un~~resolve~~d~~ issues left out of Phase 1.

C.10 [Utility] shall engage with interested stakeholders prior to the forecast being finalized and used to identify locations of proposed upgrades. This outreach shall be conducted during the first half of even-numbered years, starting in 2026.

C.10.a [Utility] shall share the initial results of its forecast and identify preliminary regions where upgrades may be needed.

C.10.b [Utility] shall give stakeholders the opportunity to send in written feedback on its initial forecast.

C.10.c Stakeholder feedback should focus on identifying geographic areas that have a higher likelihood to adopt DG and electrification that may not be represented in the utility's initial forecast.

C.10.d Utility shall provide a high-level summary of stakeholder engagement completed and feedback and where it was incorporated into the forecasting for the Proactive Upgrade Proposal, and if not, why not.

C.10.e Stakeholders with similar views are encouraged to file joint feedback with [utility].

D. Baseline Information

The following information should be provided with the IDP in which a Proactive Upgrade Proposal is submitted:

D.1 The types of upgrade projects and programs that fit within the framework and are currently considered when developing proposals. This may change over time based on utility capability.

D.2 Issues the potential project or program solves.

D.3 General range of cost for each type of upgrade.

D.4 An outline of future upgrade options, such as storage, and on what timeline they may be available.

D.5 A summary of upgrades that were previously approved but have since been accelerated, delayed, or abandoned due to a change in need since the last filing.

E. Forecast

E.1 [Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and ~~electrification~~ customer loads than expected in the base case. [Utility] shall recommend which forecast should be adopted and explain why it thinks that forecast should be the case toward which to plan and why.

E.2 Where possible, the following load and DER components shall be differentiated in the forecast data provided: distributed solar PV, CSGs, distributed energy storage, energy efficiency, demand response, electric vehicles, and electrification of space, water, and process heating.

E.3 For each of the DER components above, [utility] shall provide a discussion of each essential assumption made in preparing the forecast, including assumptions regarding customer adoption rates, cost trends, and relevant policy drivers. [Utility] should include any sensitivity analyses used to test these assumptions.

E.4 In addition to the existing IDP load and DER forecast requirements, [Utility] shall submit its forecast results for generation and peak loads at the feeder/substation level for all locations associated with proposed proactive distribution upgrades ~~and locations that the utility analyzed but decided not to upgrade~~.

E.5 All proposed proactive upgrades shall be based on a forecasted need identified in the forecast between years five and ten, unless the anticipated lead time for an upgrade project exceeds ten years.

E.6 The forecast shall include an assessment of existing available hosting capacity for generation and load to the same extent as is shared in the utility's Hosting Capacity Analysis results.

F. Potential Sites for Proactive Upgrades

A utility must include in any Proactive Upgrade Proposal filing:

F.1 The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section C.8 - Stakeholder Outreach.

F.2 A list of sites that [utility] may consider for future proactive distribution upgrades.

F.3 A list of proposed proactive distribution upgrades, including identifying any changes to upgrade locations since the last submission.

F.4 A narrative description or analysis of the impact of the proposed proactive distribution upgrades on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).

F.5 The total capital cost of all proposed upgrades and the projected total lifetime revenue requirements.

F.6 For each site where [utility] is proposing an upgrade, [utility] must provide:

F.6.a Expected type of upgrade.

F.6.b Narrative description for why the proposed upgrade or group of upgrades has been selected for the proactive upgrade process.

F.6.c Estimated upgrade cost and duration of construction.

F.6.d Increase in load and generation capacity expected to result from the proposed upgrade.

F.6.e Forecasted period before another upgrade is anticipated to be needed at the same site.

F.6.f Magnitude of forecasted growth (load or generation) and capacity gap driving the need for the proposed upgrade.

F.6.g Classes or characteristics of load or generation driving the need for the proposed upgrade.

F.6.h A quantitative or qualitative level of confidence of the forecasted need, and/or sensitivity of the forecasted need to deviations from the forecast, driving the need for the specific project. This may include any information gathered from communities, developers, customers (for example if large fleet owners, or other industrial/commercial building customers) and others that informed selection of the site.

F.6.i Identification of any known additional benefits resulting from the upgrade.

F.6.j Identification of planned capital investment or maintenance work to be coordinated with the proposed proactive distribution upgrade (where appropriate).

F.7 For sites that the utility analyzed but ultimately decided not to upgrade, the reasons the utility decided not to propose upgrades at that site.

F.8 For upgrades that are proposed as part of a longer-term plan, [utility] shall provide an assessment of whether they are expandable and whether there would be any potential benefits or costs from doing repeated work in the same area.

G. Proactive Upgrade Proposal Evaluation Criteria

Each proposed proactive distribution upgrade shall be evaluated using the following criteria, with the utility providing such information and evaluation as part of its filing:

G.1 The total capital cost of the proposed upgrade and its projected total lifetime revenue requirement.

G.2 The overall capacity gained for both load and generation.

G.3 The cost per unit of capacity gained.

G.4 The lead time for the upgrade.

G.7 The degree of certainty, qualitative or quantitative, of the forecast components driving the forecasted need at that location, and any additional certainty in the magnitude/scale of investment provided by direct customer engagement.

G.8 The remaining estimated useful life of the assets proposed to be replaced.

G.9 The estimated number of years beyond the timing of the upgrade that the project would meet the forecasted capacity needs at that location.

G.10 Narrative description or analysis of the impact of the proposed proactive distribution upgrade projects, including impacts on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).

G.11 The benefits additional to increased hosting capacity realized from the upgrade, if any, to reliability, resilience, safety, and asset health, and the value of those benefits, where known.

G.12 How any additional planned work would be coordinated with the proposed proactive distribution upgrade (where appropriate).

G.13 The extent to which the upgrade would facilitate progress toward greenhouse gas emission reduction targets.

G.15 Which desired outcomes of the proactive planning process would be facilitated by the proposed upgrade.

G.16 Feasibility of the projected upgrade project timeline including any foreseeable risks to the timeline.

H. Proposal for non-location specific proactive measures

H.1 The utility may propose programmatic investment proposals which are proactive distribution upgrade initiatives that affect a variety of locations, but the specific locations may shift over time in alignment with established site selection criteria.

J. Cost Recovery

As indicated in Section C.8 regarding Process, [Utility] must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.

Cost Recovery Mechanism

J.3 Expenditures for approved proactive upgrades shall be tracked as regulatory assets and~~/or~~ receive deferred accounting treatment to ensure that the costs of the upgrades are transparently accounted for and ~~can~~ are eligible to be recovered.

J.4 All cost-share fees collected from Cost-Share Customers shall be returned to ratepayers as an offset to the revenue requirements of proactive upgrade capital investments.

Cost Share Window

J.7 Each approved Proactive Distribution Upgrade shall have a Cost Share Window that starts the year that the Proactive Distribution Upgrade project is placed in-service. The duration of the Cost Share Window shall be until 5 years after the anticipated need date for the Proactive Distribution Upgrade at the time of approval. During the Cost Share Window, Cost-Share Fees from Cost-Share Customers act as an offset to the revenue requirements of all Proactive Distribution Upgrades.

J.8 Upon completion of the project, the total costs of the upgrade are placed into rate base. ~~At the end of the Cost Share Window, any remaining costs that have not been offset by Cost Share Fees are placed into ratebase and no longer subject to this cost sharing program.~~

J.9 Interconnecting customers that apply to interconnect on or before the cost share window end date are Cost-Share Customers. For generation interconnections, the date of applying to interconnect shall be the Deemed Complete date.

Prudency Review

J.14 The Commission's Proactive Upgrade Proposal decision constitutes an advance determination of prudence for the projects approved in the Proactive Upgrade Proposal.

J.15 If a project receives advanced determination of prudence, this means that at the time cost recovery is being considered, costs that align with the original proposal cannot be deemed imprudent.

J.16 If the Commission does not provide an advanced determination of prudence for the project, then for that reason alone, the utility may choose not to proceed with the project.

J.17 Up until the point that a previously approved project is canceled or rescinded by Commission Order, the utility is entitled to recover all costs that have been prudently incurred, not exceeding the previously approved amount.

J.19 An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding, to the extent that actual or updated projected costs exceed the prior estimate previously approved by the Commission.

K. Cost Allocation

K.1 If a change is made to distribution planning or other utility standards that impacts the amount of available hosting capacity after a proactive upgrade project has been completed, there shall be no resulting change in cost-sharing responsibility.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue.

K.2 A $/kW$_{ac}$ fee shall be charged to any Cost-Share Customers and the dollars returned to ratepayers. The fee shall be calculated at an aggregated, programmatic level for all approved proactive upgrade investments. The fee calculation shall be the total cost of all approved Proactive Distribution Upgrades-divided by the total kWac of capacity added by all approved Proactive Distribution Upgrades. This fee shall determine the pro rata cost for any Cost-Share Customer, load or generation~~, and pay down the assets until~~ which will be applied as an offset to the total revenue requirements of all Proactive Distribution Upgrade projects with an open cost share window ~~has been paid off~~.

K.3. When new Proactive Upgrade Proposals are approved, the total kWac of capacity added and total cost of the newly approved Proactive Distribution Upgrades shall be added respectively to the totals of the previously approved Proactive Distribution Upgrades. The resulting new total kWac of capacity added and total cost of all Proactive Distribution Upgrades shall be used to calculate the new $/kWac fee that shall be charged to any Cost-Share Customers beginning after the date the new Proactive Upgrade Proposal is approved.

K.4 Any DG interconnections that are subject to the Priority Queue shall not be Cost-Share Customers.

K.5 Load interconnections that are demand metered shall be Cost-Share Customers. Load interconnections that are not demand metered shall not be Cost-Share Customers.

K.6 Any Proactive Distribution Upgrade costs recovered from ratepayers shall be treated consistent with approved rate case allocators and established revenue requirement procedures.

L. Capacity Reservation

L.4 [Utility] shall implement a system-wide capacity reservation for small DG to facilitate more efficient queue processing through the Priority Queue.

L.4.a Small DG (less than 40kW$_{ac}$) shall continue to be able to use the Small DER Cost Sharing Fund for service transformer and secondary upgrades at the existing funding levels and fees consistent with the Cost Sharing Program.

M. Reporting

M.1 [Utility] must file reports that include the following information and data to the greatest extent practicable. Where [utility] is not able to provide the required information, the Company shall explain why it is unable to do so. Such reports must be filed annually on November 1 as part of [utility's] Integrated Distribution Plan or Annual Update. Where applicable, [utility] must include data in spreadsheet (.xlsx) format. If [utility] also files a PDF version of spreadsheet data, it must be filed as an attachment in a separate document instead of being merged with the main report.

M.3 For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.4 and M.5.

M.4 For all proactive upgrades –

	Approved	Development	Construction	Completed	Total
Number of projects					
Upgrades in Environmental Justice Communities					
Total $ approved					
Total $ spent					
Total $ and percent of project costs recovered from interconnection customers					
Total incremental generation hosting capacity gained					
Total incremental load hosting capacity gained					

M.5 By upgrade project –

	[Project Name]	[Project Name]	[Project Name]
Year Proposed	e.g. 2025 Proposal		
Located in EJ Community (y/n)			
Anticipated completion year at time of proposal			
Date cost share window closed (actual or predicted)			
Project status (approved, development, construction, completed, terminated)			
Year completed or current anticipated year of completion			
Total incremental generation hosting capacity gained			
Utilization of capacity post upgrade (generation)			
Total incremental load hosting capacity gained			
Utilization of capacity post upgrade (load)			
Total $ approved			
Total $ spent			
Total $ and percent of project costs recovered from interconnecting customers (load or generation)			

M.6 DER additions (Fill out table for each completed project)
[Project Name]

	40kW and under (BTM)	Over 40kW (BTM)	Front of the Meter	Total
Number of DERs added since project completion				
Solar				
Battery				
Other (Specify)				
Capacity of DERs added since project completion				
Solar				
Battery				
Other (Specify)				

M.7 For each completed project, the current peak load, forecasted peak load, and any known load additions by load type (Fleet EV charging, DCFC fast charging, etc.) and customer class

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue.

M.8 A comparison of Load and DG added since project completion with the forecast from the Proactive Upgrade Proposal.

M.9 Any additional narrative information, by project or portfolio, on the status of the project, cost deviations from the approved amount, and any delays in implementation and the cause for the delays.

M.10 For any approved projects that did not proceed, an explanation of why and what the impact is on the overall program budget.

M.12 For projects that were accelerated, delayed, or abandoned following Commission approval, [utility] shall discuss the impact of the ~~that~~ change ~~on total proactive grid upgrade costs, cost allocation, and benefit allocation~~.

Xcel Energy Preferred Phase 2 Proposal

Timing:

1. Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by ~~Q2~~Q4 of ~~2027~~2026.

4. Forecasting for FTM generation to identify proactive upgrades, including whether to do a service territory wide analysis of optimal sites for front of the meter generation.

7. Additional discussion on system wide capacity reservations.

8. A full review of the Proactive Upgrade Framework to incorporate a process for identifying proactive infrastructure upgrades to enable hosting capacity for front of the meter distributed generation.

Note: Original red-line is noted in red; Xcel Energy proposed modifications are noted in blue

Requirement No.	Requirement	Position	Justification
A. Introduction			
Any combination of goals may be adopted with the following exceptions:			
A.1 and A.2 are alternatives.			
A.4 and A.5 are alternatives.			
A.6 and A.7 are alternatives			
A.8 and A.9 are alternatives			
	The Commission establishes the following framework for proactive distribution upgrades for [utility] to achieve the following goals:		
A.1	Proactively plan for the distribution system upgrades necessary to meet state energy policy requirements and goals.	Do Not Oppose	
OR			
A.2	Proactively plan for the distribution system upgrades necessary to ~~meet state energy policy requirements and goals~~ enable customer DER and electrification adoption, considering state energy policy requirements and goals.	Support	
A.3	Meet customer expectations by reducing or eliminating the wait time to interconnect DERs and new load to the extent reasonably possible.	Support	
A.4	Protect ratepayers by establishing a rigorous review of proposed proactive investments to ensure they do not cause undue costs or result in inequitable distribution of costs or benefits.	Oppose	We believe that A.5 provides greater clarity on the risks and costs we aim to minimize with this framework.
OR			
A.5	Protect ratepayers by establishing a ~~rigorous~~ review of proposed proactive investments to ~~ensure they do not cause undue risk costs or~~ minimize the risk of stranded assets or projects that result in inequitable distribution of costs or benefits.	Support	
A.6	Maximize the benefits to the distribution system while minimizing the costs.	Oppose	We believe A.7 is more balanced and realistic. We agree with aiming to ensure that the benefits outweigh the costs whenever possible, as stated in A.7.
OR			
A.7	To the extent reasonably possible, maximize the benefits to the distribution system while minimizing the costs.	Support	
A.8	Limit cost impacts to ratepayers from forecast inaccuracies.	Oppose	All forecasts will be inaccurate because they attempt to predict the future. A.9 better clarifies that this framework should aim to limit the risk of excessively inaccurate forecasts.
OR			
A.9	Limit cost impacts from unreasonable forecast inaccuracies.	Support	
Any combination of principles may be adopted with the following exceptions:			
A.11 and A.12 are alternatives.			
A.13 and A.14 are alternatives.			
	The Commission establishes the following principles to guide allocation of the costs of proactive upgrades:		
A.10	Limit deviations from traditional cost allocation and recovery processes to the extent possible.	Support	
A.11	Costs should be allocated to the customers or classes causing the costs, when appropriate.	Support	
OR			
A.12	Costs should be allocated to the customers or classes causing the costs, ~~when appropriate~~ whenever possible.	Oppose	We prefer "when appropriate" as stated in A.11 and believe that rate cases are the best place to determine class allocators and appropriateness criteria.
A.13	If cost-causation cannot be determined, costs should be allocated according to the distribution of benefits.	Oppose	We strongly oppose using custom allocation formulae to allocate project costs. Only approved cost allocators from approved rate cases should be used.
OR			
A.14	~~If cost-causation cannot be determined, costs should be allocated according to~~ Cost allocation may take into account the distribution of benefits.	Oppose	We believe A.14 creates unnecessary ambiguity regarding whether cost allocation should follow the rate case methodology.
A.15	Costs should be allocated according to the distribution of benefits.	Oppose	A.15 conflates cost allocation with cost causation. Costs are recovered from cost causers on a pro rata basis, according to the distribution of benefits. Remaining costs that are not recovered from cost causers are recovered through base rates and should be allocated in the same as all other system costs.
B. Definitions			
Any combination of definitions may be adopted with the following exceptions:			
B.1 and B.2 are alternatives.			
B.7 and B.8 are alternatives.			
B.14 and B.15 are alternatives			
	The Commission adopts the following definitions for the purposes of this framework:		
B.1	Cost-Share Customer: a customer who applies to interconnect either load or generation at a location served by a Proactive Distribution Upgrade with an open cost-share window.	Oppose	We believe that B.2 is necessary to clarify that a Cost-Share Customer is a customer responsible for paying a Cost-Share Fee. Depending on which other framework components are approved, not all interconnecting customers at proactively upgraded locations will necessarily be responsible for paying a Cost-Share Fee.
OR			
B.2	Cost-Share Customer: a customer who applies to interconnect either load or generation at a location served by a Proactive Distribution Upgrade with an open cost-share window and is responsible for paying a Cost-Share Fee, unless otherwise specified in approved tariffs.	Support as modified	
B.3	Cost-Share Fee: the amount a Cost-Share Customer pays to access a location served by a Proactive Distribution Upgrade.	Support	
B.4	Cost-Share Window: the period during which Cost-Share Fees are collected from Cost-Share Customers.	Support	
B.5	Distribution Capacity Upgrade: A distribution system upgrade at the substation or feeder level that increases hosting capacity for load and/or generation on the distribution system.	Support	
B.6	Distributed Energy Resource (DER): Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.	Support	
B.7	Distributed Generation (DG): a facility that has a capacity of 10 MW or less, is interconnected with a utility's distribution system, operates in parallel with the utility, and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures.	Oppose	B.8 is a more generally applicable definition.
OR			
B.8	Distributed Generation (DG): a generation facility that ~~has a capacity of 10 MW or less,~~ is interconnected with a utility's distribution system~~,~~ and operates in parallel with the utility~~, and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures~~.	Support	
B.9	Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes.	Support	
B.10	Forecasted/Proactive Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under forecasted system conditions.	Support	
B.11	Hosting Capacity: The amount of DG or load that distribution equipment can host without exceeding thermal, voltage, protection, or other thresholds under existing system conditions.	Support	
B.12	Integrated Distribution Plan: the biennial report established in Docket E002/CI-18-251 and as currently outlined in the filing requirements available [here].	Support	
B.13	Priority Queue: The queue for "customer-sited" Interconnection Applications up to 40 kWac and applications that are a part of the Solar for Schools or Solar on Public Buildings legislative programs that comply with the 120% rule, as detailed on tariff sheet 10-81.5.	Support	
B.14	Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework.	Oppose	We believe B.15 adds important specificity to differentiate traditional investments from investments made under the Proactive Distribution Upgrade Framework, which is the driver for the development of a Proactive Upgrade Proposal.
OR			

Requirement No.	Requirement	Position	Justification
B.15	Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework. In the context of this framework, the Proactive Distribution Upgrades submitted in the Proactive Upgrade Proposal would not be considered prudent under existing distribution planning practices due to the proactive nature of the projects.	Support	
B.16	Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle.	Support	
B.17	Small DER Cost Sharing Fund: [Utility's] cost sharing fund for MN DIP applications of 40kW$_{ac}$ or less as detailed on [tariff sheet 10-81.4].	Support	
C. Process			
C.1 through C.4, C.8, and C.9 may be adopted in any combination.			
C.5 through C.7 are alternatives and one may be adopted with any other requirements.			
C.10 and C.11 both pertain to stakeholder engagement and may be adopted individually, together, or not at all.			
C.1	[Utility] may file a Proactive Upgrade Proposal in conjunction with its Integrated Distribution Plan (IDP) due on November 1 of odd numbered years. The Proactive Upgrade Proposal shall be evaluated through the same docket and process as the IDP but is not part of the IDP.	Support	
C.2	The Proactive Upgrade Proposal may include proactive distribution upgrades that have not been initiated and shall begin construction within five years from the date of the filing. It may also contain proactive distribution upgrades that are not specific to a single location but shall upgrade the same type of asset(s) across multiple locations.	Support	
C.3	The Proactive Upgrade Proposal must demonstrate alignment with the framework, and the Commission shall review and approve, deny, or modify the Proposal with a goal of completion within 12 months from the date of the initial filing.	Support	
C.4	[Utility] is not obligated to initiate a project if it is approved in the Proactive Upgrade Proposal. If [utility] does not proceed with an approved project, it shall explain why and the impact on the overall program budget with its Annual Report, as described in L. Reporting - 9 below.	Support	
C.5	Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes would be considered scope changes to the project that would substantially impact overall project cost.	Support as modified	Support with the modification to include "substantially" considering that small changes that minimally impact the overall cost should not require reapproval.
OR			
C.6	Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes include but are not limited to scope changes to the project that would impact overall project cost.	Oppose	If previously-approved projects are continually at risk of being reviewed for reapproval for non-specific reasons, that introduces an unacceptable level of risk and the Company is not likely to initiate a project under this Framework.
OR			
C.7	Previously approved projects do not require reapproval in subsequent Proactive Upgrade Proposal evaluations unless circumstances have changed significantly. Significant changes would be considered scope changes to the project that would impact overall project cost. Projects that have already incurred charges would not need reapproval, however scope changes would require Commission approval.	Oppose	The redline in this requirement could be understood to be conflicting. The redline also does not give consideration to the magnitude of the change. Minimal scope changes that do not change the amount of capacity being created by the project and also minimally impact the overall cost should not require reapproval.
C.8	As addressed further in Section J: Cost Recovery, the Utility must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.	Support	
C.9	The Proactive Upgrade Framework is subject to refinement through the Proactive Grid Upgrade Workgroup. The Proactive Grid Upgrade Workgroup shall be convened by Commission Staff and shall meet as necessary to refine and improve the Proactive Upgrade Framework. This shall include Phase 2 of the framework development in 2025 and 2026 to ~~un~~resolve~~d~~ issues left out of Phase 1.	Support as modified	
C.10	[Utility] shall engage with interested stakeholders prior to the forecast being finalized and used to identify locations of proposed upgrades. This outreach shall be conducted during the first half of even-numbered years, starting in 2026.	Support	
C.10.a	[Utility] shall share the initial results of its forecast and identify preliminary regions where upgrades may be needed.	Support	
C.10.b	[Utility] shall give stakeholders the opportunity to send in written feedback on its initial forecast.	Support	
C.10.c	Stakeholder feedback should focus on identifying geographic areas that have a higher likelihood to adopt DG and electrification that may not be represented in the utility's initial forecast.	Support	
C.10.d	Utility shall provide a high-level summary of stakeholder engagement completed and feedback and where it was incorporated into the forecasting for the Proactive Upgrade Proposal, and if not, why not.	Support	
C.10.e	Stakeholders with similar views are encouraged to file joint feedback with [utility].	Support	
C.11	Coordination with distributed generation developers:	Oppose	Xcel Energy believes that more discussion is needed on the topics outlined in C.11a-f during Phase 2. 1. The DGWG, which anyone can bring a matter to at any time, could potentially fill this role. The Commission also has a DGAG to consider policy issues. 2. The Commission does not have authority over developers and other interested parties and cannot require specific groups to attend or participate. 3. A utility's role in stakeholder engagement related to this process should be to collect and consider input for our forecast. Stakeholders are free to organize on their own and submit aggregated feedback for consideration. 4. Utilities have a statutory obligation to provide safe, adequate, and efficient service to the public at reasonable rates. Utilities also cannot give preferential treatment. This term would give DG developers an outsized voice over a utility's investment plans that need to also consider load customers. Developer input should be limited to the forecast and not to prioritizing specific projects. 5. Utilities need to reserve the right to incorporate any input from developers only where appropriate.
C.11.a	[Utility] shall establish a distributed generation stakeholder engagement group (DGEG) to coordinate stakeholder engagement with the Utility on proactive long-term system planning. The DGEG shall be co-facilitated by the [utility] and a DG stakeholder representative and shall consist of one representative from the Department of Commerce, one representative from the Office of the Attorney General, and six DG stakeholder representatives (one of which must be a developer that conducts 60% or more of its business in residential DG, one of which must be a developer that conducts 60% or more of its business in C&I DG, one of which must be a developer that conducts 50% or more of its business in energy storage). DG industry trade associations shall work together to conduct industry elections for the six DG stakeholder representatives for each IDP iteration.	Oppose	
C.11.b	[Utility] must engage with the DGEG to collect input for the forecast prior to it being finalized and used to identify locations of proposed upgrades. Forecast input should focus on identifying geographic areas that have a higher likelihood to adopt DG and electrification.	Oppose	
C.11.c	[Utility] must engage with the DGEG to collect input for prioritizing infrastructure upgrades at the planning stage of the analysis prior to Proactive Upgrade Proposal to the Commission.	Oppose	
C.11.d	DGEG input must be collected in a manner that can be incorporated into the [utility's] forecasting tool and for use in prioritizing infrastructure upgrades in a Proactive Upgrade Proposal.	Oppose	
C.11.e	The Utility must include DGEG recommendations in its Proactive Upgrade Proposal filing with the Commission and explain how it did or did not incorporate recommendations.	Oppose	
C.11.f	[Utility] must also collect DGEG input to inform prioritization of site proposals. This outreach shall be conducted during the first half of odd-numbered years, in the lead up to finalizing site proposals for the November 1 filing in odd-numbered years.	Oppose	
D. Baseline Information			
Any requirements may be adopted in any combination.			
The following information should be provided with the IDP in which a Proactive Upgrade Proposal is submitted:			
D.1	The types of upgrade projects and programs that fit within the framework and are currently considered when developing proposals. This may change over time based on utility capability.	Support	
D.2	Issues the potential project or program solves.	Support	
D.3	General range of cost for each type of upgrade.	Support	
D.4	An outline of future upgrade options, such as storage, and on what timeline they may be available.	Support	

Requirement No.	Requirement	Position	Justification
D.5	A summary of upgrades that were previously approved but have since been accelerated, delayed, or abandoned due to a change in need since the last filing.	Support	
E. Forecast			
Any requirements may be adopted in any combination.			
E.1	[Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and ~~electrification~~customer loads than expected in the base case. [Utility] shall recommend which forecast should be adopted and explain why it thinks that forecast should be the case toward which to plan and why.	Support as modified	Our modification intends to clarify that electrification loads are not the only type of customer loads modeled in the forecast, and other types of customer loads may contribute to a project's need.
E.2	Where possible, the following load and DER components shall be differentiated in the forecast data provided: distributed solar PV, CSGs, distributed energy storage, energy efficiency, demand response, electric vehicles, and electrification of space, water, and process heating.	Support	
E.3	For each of the DER components above, [utility] shall provide a discussion of each essential assumption made in preparing the forecast, including assumptions regarding customer adoption rates, cost trends, and relevant policy drivers. [Utility] should include any sensitivity analyses used to test these assumptions.	Support	
E.4	In addition to the existing IDP load and DER forecast requirements, [Utility] shall submit its forecast results for generation and peak loads at the feeder/substation level for all locations associated with proposed proactive distribution upgrades ~~and locations that the utility analyzed but decided not to upgrade~~.	Support as modified	We support discussing the projects that did not move forward but do not support providing forecast data for those locations. The utility should be responsible for deciding which projects to pursue based on the needs of the system. Further, the review of a Proactive Upgrade Proposal should determine the merits of projects that have been proposed, and should not be used debate which projects *should have* been proposed.
E.5	All proposed proactive upgrades shall be based on a forecasted need identified in the forecast between years five and ten, unless the anticipated lead time for an upgrade project exceeds ten years.	Support	
E.6	The forecast shall include an assessment of existing available hosting capacity for generation and load to the same extent as is shared in the utility's Hosting Capacity Analysis results.	Support	
F. Potential Sites for Proactive Upgrades			
Any requirements may be adopted in any combination.			
A utility must include in any Proactive Upgrade Proposal filing:			
F.1	The criteria used to identify potential sites for proactive distribution upgrades, including a discussion of feedback received from stakeholders under Section C.8 - Stakeholder Outreach.	Support	
F.2	A list of sites that [utility] may consider for future proactive distribution upgrades.	Support	
F.3	A list of proposed proactive distribution upgrades, including identifying any changes to upgrade locations since the last submission.	Support	
F.4	A narrative description or analysis of the impact of the proposed proactive distribution upgrades on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).	Support	
F.5	The total capital cost of all proposed upgrades and the projected total lifetime revenue requirements.	Support	
F.6	For each site where [utility] is proposing an upgrade, [utility] must provide:	Support	
F.6.a	Expected type of upgrade.	Support	
F.6.b	Narrative description for why the proposed upgrade or group of upgrades has been selected for the proactive upgrade process.	Support	
F.6.c	Estimated upgrade cost and duration of construction.	Support	
F.6.d	Increase in load and generation capacity expected to result from the proposed upgrade.	Support	
F.6.e	Forecasted period before another upgrade is anticipated to be needed at the same site.	Support	
F.6.f	Magnitude of forecasted growth (load or generation) and capacity gap driving the need for the proposed upgrade.	Support	
F.6.g	Classes or characteristics of load or generation driving the need for the proposed upgrade.	Support	
F.6.h	A quantitative or qualitative level of confidence of the forecasted need, and/or sensitivity of the forecasted need to deviations from the forecast, driving the need for the specific project. This may include any information gathered from communities, developers, customers (for example if large fleet owners, or other industrial/commercial building customers) and others that informed selection of the site.	Support	
F.6.i	Identification of any known additional benefits resulting from the upgrade.	Support	
F.6.j	Identification of planned capital investment or maintenance work to be coordinated with the proposed proactive distribution upgrade (where appropriate).	Support	
F.7	For sites that the utility analyzed but ultimately decided not to upgrade, the reasons the utility decided not to propose upgrades at that site.	Support	
F.8	For upgrades that are proposed as part of a longer-term plan, [utility] shall provide an assessment of whether they are expandable and whether there would be any potential benefits or costs from doing repeated work in the same area.	Support	
G. Proactive Upgrade Proposal Evaluation Criteria			
G.14 and G.15 are alternatives, otherwise any requirements may be adopted in any combination.			
Each proposed proactive distribution upgrade shall be evaluated using the following criteria, with the utility providing such information and evaluation as part of its filing:			
G.1	The total capital cost of the proposed upgrade and its projected total lifetime revenue requirement.	Support	
G.2	The overall capacity gained for both load and generation.	Support	
G.3	The cost per unit of capacity gained.	Support	
G.4	The lead time for the upgrade.	Support	
G.5	The risk of deferring the upgrade, or using the existing distribution planning process, including quantifying the potential energization delays (in years) and number of customers impacted by delays	Oppose	We believe this is redundant with G.4, and that G.4 is more appropriate. The risk of deferring a proactive upgrade is that a reactive upgrade would have to be implemented when a need arises. In this case, the delay in energization for interconnecting customers that trigger the need would be the lead time for the upgrade.
G.6	Discussion of whether [utility] performed a non-wires alternative (NWA) for the project, and if so, the results of the analysis. If [utility] did not perform an NWA, provide a discussion of alternative measures that could be taken to mitigate the risk(s) the upgrade is intended to address, including energy-conservation, load-management measures and/or flexible interconnection.	Oppose	Projects that meet the IDP criteria for NWA analysis will have the results shared in the Company's concurrent IDP filing. Requiring the Company to conduct similar analyses for projects that do not meet the IDP criteria for NWA analysis significantly increases pressure on Company resources to support Proactive Upgrade proposals.
G.7	The degree of certainty, qualitative or quantitative, of the forecast components driving the forecasted need at that location, and any additional certainty in the magnitude/scale of investment provided by direct customer engagement.	Support	
G.8	The remaining estimated useful life of the assets proposed to be replaced.	Support	
G.9	The estimated number of years beyond the timing of the upgrade that the project would meet the forecasted capacity needs at that location.	Support	
G.10	Narrative description or analysis of the impact of the proposed proactive distribution upgrade projects, including impacts on Environmental Justice Areas, as defined by Minn. Stat. §216B.1691, Subd. 1 (e).	Support	
G.11	The benefits additional to increased hosting capacity realized from the upgrade, if any, to reliability, resilience, safety, and asset health, and the value of those benefits, where known.	Support	
G.12	How any additional planned work would be coordinated with the proposed proactive distribution upgrade (where appropriate).	Support	
G.13	The extent to which the upgrade would facilitate progress toward greenhouse gas emission reduction targets.	Support	
G.14	Which of the following desired outcomes of the proactive planning process would be facilitated by the proposed upgrade?	Oppose	G.15 is superior to G.14. We believe these are addressed by information provided in other parts of the framework.
G.14.a	Anticipate Adoption Speed: Increased adoption speed of DERs and electrification by removing grid barriers.	Oppose	
G.14.b	Coordinate Impacts: Avoided risk of construction/procurement bottlenecks.	Oppose	
G.14.c	Efficiency: Degree of lifecycle cost reduction or overall spending efficiency achieved.	Oppose	
OR			
G.15	Which desired outcomes of the proactive planning process would be facilitated by the proposed upgrade.	Support	
G.16	Feasibility of the projected upgrade project timeline including any foreseeable risks to the timeline.	Support	
H. Proposal for Non-Location Specific Proactive Measures			
H.1 and H.2 may be adopted. H.1 may be adopted without H.2			
H.1	The utility may propose programmatic investment proposals which are proactive distribution upgrade initiatives that affect a variety of locations, but the specific locations may shift over time in alignment with established site selection criteria.	Support	
H.2	In proposing such measures or initiatives, the utility shall consider whether there are basic, low-cost upgrades that can be done as a part of standard maintenance.	Oppose	It is not clear what this item is requiring. Coordinating maintenance with project work is part of the Company's existing processes.
J. Cost Recovery			
As indicated in Section C.8 regarding Process, [Utility] must pursue cost recovery through a separate proceeding for any incurred Proactive Upgrade Proposal expenditures.			

Requirement No.	Requirement	Position	Justification
Cost Recovery Mechanism			
J.1 and J.2 may be adopted together or individually			
J.3 is an alternative to J.1 and J.2			
J.4 may be selected with either of the above requirements			
J.1	[Utility] may place proactive distribution upgrade investments, or portions of upgrade investments in service as regulatory assets.	Do not oppose	
J.2	[Utility] may request deferred-accounting treatment for approved proactive distribution upgrade investments. The Commission shall grant, deny, or modify the request with the Proactive Upgrade Proposal decision.	Do not oppose	
J.3	Expenditures for approved proactive upgrades shall be tracked as regulatory assets and~~/or~~ receive deferred accounting treatment to ensure that the costs of the upgrades are transparently accounted for and ~~can~~ are eligible to be recovered.	Support as modified	We do not believe an additional process is necessary for deferred accounting. Additionally, our modification is intended to eliminate ambiguity regarding cost recovery for approved projects.
J.4	All cost-share fees collected from Cost-Share Customers shall be returned to ratepayers as an offset to the revenue requirements of proactive upgrade capital investments.	Support as modified	Our modification intends to clarify how cost-share fees will be returned to ratepayers.
Cost Share Window			
J.5 and J.6 are a package.			
J.5	Each approved proactive distribution upgrade shall have a cost-share window of at least 15 years that starts upon the upgrade being placed in service. During the cost-share window, cost-share fees from Cost-Share Customers act as an offset to the utility's capital investment in the proactive distribution upgrade. No costs are socialized to ratepayers during this time.	Oppose	Costs incurred by the utility must be recovered within a reasonable amount of time; 15 years is unreasonable. Additionally, 15 years after the upgrade does not take into account when the forecasted need for the project would arise. A proactive upgrade might be justified by a forecast showing an accelerated rate of adoption that doesn't begin for ten years. Determining the cost-share window based on the in-service date alone fails to ensure that the anticipated adoption is captured within the cost-share window. For this reason, we believe that J.7 is a better alternative.
AND			
J.6	Where socialization of an upgrade's cost (i.e., rate-base treatment) begins with the utility's next rate case following the upgrade's in-service date, the cost-share window for that upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.	Oppose	Keeping the cost-share window open for the full life of the asset is unreasonably burdensome for the utility to track and administer. This burden will further increase with each proactive upgrade that is approved over the lifetime of this framework.
J.7 through J.9 is a package.			
J.7	Each approved Proactive Distribution Upgrade shall have a Cost Share Window that starts the year that the Proactive Distribution Upgrade project is placed in-service. The duration of the Cost Share Window shall be until 5 years after the anticipated need date for the Proactive Distribution Upgrade at the time of approval. During the Cost Share Window, Cost-Share Fees from Cost-Share Customers act as an offset to the revenue requirements of all Proactive Distribution Upgrades.	Support	
AND			
J.8	Upon completion of the project, the total costs of the upgrade are placed into rate base. ~~At the end of the Cost Share Window, any remaining costs that have not been offset by Cost Share Fees are placed into ratebase and no longer subject to this cost sharing program.~~	Support as modified	
AND			
J.9	Interconnecting customers that apply to interconnect on or before the cost share window end date are Cost-Share Customers. For generation interconnections, the date of applying to interconnect shall be the Deemed Complete date.	Support	
Cost Cap			
J.10 establishes a cost cap. J.11 and J.12 may be adopted with J.10			
J.10	Total proactive upgrade costs recoverable from ratepayers shall be capped in some manner, such as a percentage of the total capacity-related five-year budget in the IDP, or a specified dollar cap on proactive upgrades. The cost cap shall be determined as part of the Commission's first Proactive Upgrade Proposal decision.	Oppose	We do not believe that a cost cap is necessary. Budgeting for proactive upgrades will be part of the utility's broader budgeting process, and will be allocated capital based on the need determined by the utility, the availability of capital, and other factors. However, if a cost cap is implemented we believe that J.11 and J.12 are necessary additions to clarify how the cap should function.
J.11	Capital expenditures that have been offset by cost-share fees do not count against the cap.	Oppose	
J.12	After a project's cost-share window has closed, the project shall be considered system assets and associated costs shall no longer count against the cap.	Oppose	
Prudency Review			
J.13 is an alternative to J.14 through J.16			
J.17 may be adopted with J.13 or J.14-16			
J.18 and J.19 are alternatives and either may be adopted with J.13 or J.14-16			
J.13	The Commission's Proactive Upgrade Proposal decision creates a rebuttable presumption, in a cost-recovery proceeding, that upgrades completed consistent with the decision are prudent.	Oppose	A rebuttable presumption will not provide resonable certainty to the utility that costs will be recovered after a project is approved. Projects that have been approved by the Commission should not be fully re-scrutinized during cost recovery unless for specific reasons that the utility can reasonably anticipate. This is necessary so that utility's can make appropriate decisions on whether to proceed with a project or not as detailed scope and costs are refined after approval.
OR			
J.14	The Commission's Proactive Upgrade Proposal decision constitutes an advance determination of prudence for the projects approved in the Proactive Upgrade Proposal.	Support	
AND			
J.15	If a project receives advanced determination of prudence, this means that at the time cost recovery is being considered, costs that align with the original proposal cannot be deemed imprudent.	Support	
AND			
J.16	If the Commission does not provide an advanced determination of prudence for the project, then for that reason alone, the utility may choose not to proceed with the project.	Support	
J.17	Up until the point that a previously approved project is canceled or rescinded by Commission Order, the utility is entitled to recover all costs that have been prudently incurred, not exceeding the previously approved amount.	Support	
J.18	An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding.	Oppose	"Substantial evidence" is not specific enough to inform utility decisions when implementing a project after approval. Projects that have been approved by the Commission should not be fully re-scrutinized during cost recovery unless for specific reasons that the utility can reasonably anticipate. This is necessary so that utilities can make appropriate decisions on whether to proceed with a project or not as scope and costs are refined after approval.
OR			
J.19	An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding, to the extent that actual or updated projected costs exceed the prior estimate previously approved by the Commission.	Support	
K. Cost Allocation			
K.1 is a standalone option and may be adopted with any of the following requirements.			
K.1	If a change is made to distribution planning or other utility standards that impacts the amount of available hosting capacity after a proactive upgrade project has been completed, there shall be no resulting change in cost-sharing responsibility.	Support	
K.2 - K.6 is a package.			
K.2	A $/kW$_{ac}$ fee shall be charged to any Cost-Share Customers and the dollars returned to ratepayers. The fee shall be calculated at an aggregated, programmatic level for all approved proactive upgrade investments. The fee calculation shall be the total cost of all approved Proactive Distribution Upgrades~~-~~divided by the total kWac of capacity added by all approved Proactive Distribution Upgrades. This fee shall determine the pro rata cost for any Cost-Share Customer, load or generation, ~~and pay down the assets until~~which will be applied as an offset to the total revenue requirements of all Proactive Distribution Upgrade projects with an open cost share window~~has been paid off~~.	Support as modified	
AND			

Requirement No.	Requirement	Position	Justification
K.3.	When new Proactive Upgrade Proposals are approved, the total kWac of capacity added and total cost of the newly approved Proactive Distribution Upgrades shall be added respectively to the totals of the previously approved Proactive Distribution Upgrades. The resulting new total kWac of capacity added and total cost of all Proactive Distribution Upgrades shall be used to calculate the new $/kWac fee that shall be charged to any Cost-Share Customers beginning after the date the new Proactive Upgrade Proposal is approved.	Support	
AND			
K.4	Any DG interconnections that are subject to the Priority Queue shall not be Cost-Share Customers.	Support	
AND			
K.5	Load interconnections that are demand metered shall be Cost-Share Customers. Load interconnections that are not demand metered shall not be Cost-Share Customers.	Support	
AND			
K.6	Any Proactive Distribution Upgrade costs recovered from ratepayers shall be treated consistent with approved rate case allocators and established revenue requirement procedures.	Support	
K.7 - K.12 is a package			
K.7	Insofar as proactive upgrades are associated with forecasted needs associated with identifiable customers, those customers shall be considered Cost-Share Customers and shall be allocated costs consistent with existing CIAC policies.	Oppose	We do not support K.7-K.20 that propose unique cost allocation for individual projects. All costs allocated to ratepayers should only use existing cost allocators from an approved rate case. Further, all upgrade projects will increase capacity for both load and generation and will enable adoption of either. Upgrade projects should not be categorized as enabling one or the other.
K.7.a	The proactive share of the eligible CIAC for small load additions from the residential class should be structured similarly to the 40 kW and under small DER cost share.	Oppose	See K.7
AND			
K.8	For proactive upgrade projects serving large commercial and industrial customers, proactive upgrades will be tracked separately from other rate-base assets and their total cost allocated based on large commercial and industrial's aggregate contribution to need for proactive upgrade.	Oppose	See K.7
AND			
K.9	For upgrades primarily intended to enable load growth by residential and small commercial customers, traditional cost allocation methods in a rate case shall apply. Specifically, the utility shall record costs from the upgrades in their respective FERC accounts and allocate costs with cost allocators from the utility's most recent rate case.	Oppose	See K.7
AND			
K.10	Insofar as proactive upgrade costs are recovered from customers through CIAC, those revenues shall be returned to ratepayers. Costs recovered through these tools should "pay down" the remaining unattributable proactive upgrade costs that are socialized to ratepayers.	Oppose	See K.7
AND			
K.11	Proactive distribution upgrade projects, or portions of upgrade projects, that enable DG interconnection, shall assess an upfront $/kW$_{ac}$ fee to Interconnection Cost-Share Customers seeking to interconnect generation.	Oppose	See K.7
K.11.a	Fees shall continue to be collected beyond the original date of the forecasted need if capacity remains	Oppose	See K.7
K.11.b	Initial fees could be set to target recovering a certain threshold of the upgrade costs from interconnections, such as the $/kW$_{ac}$ fee set higher than the forecasted amount, which could be applied for the first X% of capacity.	Oppose	See K.7
K.11.c	The existing small DER cost sharing program may be used to fund the upgrade fee.	Oppose	See K.7
AND			
K.12	Insofar as proactive upgrade costs are recovered from customers through Interconnection Cost-Share Fees those revenues shall be returned to ratepayers. Costs recovered through this tool should "pay down" the remaining unattributable proactive upgrade costs that are socialized to ratepayers.	Oppose	See K.7
K.13 - K.19 is a package			
K.13	When both load and DG are forecasted to benefit from a Proactive Distribution Upgrade, costs shall be categorized and allocated based on the type of benefit the upgrade provides, which may be either 'DG-Enabling' (to DG customers), or 'Reliability-Enhancing' (to load customers).	Oppose	See K.7
AND			
K.14	Utilities shall collect pro rata cost per kW$_{ac}$ fees from all interconnecting load or DG facilities over 40kWac that utilize capacity associated with an upgrade for a period of *[XXX years]* from project approval, or until all additional capacity is subscribed.	Oppose	See K.7
AND			
K.15	A per $/kWac fee shall apply to all DG interconnections over 40kWac using capacity from a Proactive Distribution Upgrade.	Oppose	See K.7
K.15.a	DG interconnections under 40kWac and subject to the Priority Queue are exempt from per $/kWac fees.	Oppose	See K.7
K.15.b	DG Interconnections under 40kWac that are not subject to the Priority Queue (under 40kWac systems projected to generation more than 120% of onsite load) shall be subject to per $/kWac fees, and shall pay the per $/kWac fees for upgrade costs directly.	Oppose	See K.7
AND			
K.16	Project "payback" tracking shall: a. Monitor both financial recovery and capacity utilization percentages separately b. Record CIAC payments as direct offsets to project costs c. Consider a project "paid off" when either 100% of costs are recovered or [XXX years] have elapsed.	Oppose	See K.7
K.16.a	Capacity utilized by Priority Queue customers 40kW DG shall not count towards 'DG-Enabling' capacity utilization metrics if the utility has a planning limit in place at the location of the upgrade.	Oppose	See K.7
AND			
K.17	All collected fees offset ratepayer costs for the upgrade investments. All fee revenue shall be returned directly to ratepayers as offsets to the specific project costs and allocated in proportion to how the initial costs were assigned to ratepayer classes	Oppose	See K.7
AND			
K.18	Initial costs prior to fee collection shall be temporarily allocated to ratepayer classes based on forecasted benefit distribution.	Oppose	See K.7
K.18.a	For DG-enabling portions, recorded as regulatory assets with carrying costs.	Oppose	See K.7
K.18.b	For load-enabling portions, included in standard distribution rates.	Oppose	See K.7
AND			
K.19	After the cost-share window closes, any unrecovered costs shall become permanent rate-based system assets and be allocated to customer classes according to standard cost allocation procedures.	Oppose	See K.7
K.20 is a standalone option			
K.20	When both load and DG are each forecasted to grow and thus both benefit from a given selection of proactive upgrades, costs shall be allocated between ratepayers and DG customers to the extent at which each relies on such upgrades. Allocation, therefore, requires categorizing the benefits provided by a given upgrade. These can range between strictly 'DG-Enabling' allocated to interconnecting DG customers, strictly 'Reliability-Enhancing' allocated to load customers, and 'Capacity-Expansion' co-benefits split between DG and load customers. The split of cost for 'Capacity-Expansion' upgrades is to be determined by the ratio of either enabled forecasted load or DG to total enabled forecasted load and DG.	Oppose	See K.7
K.21 - K.26 are standalone options, but would need to be adopted in conjunction with package options above.			
K.21	For upgrades primarily intended to enable DG adoption for residential and small commercial customers, the utility shall socialize the upgrade costs through the Small DER Cost Sharing Fund. If a customer that does not qualify for the Small DER Cost Sharing Fund interconnects to a location served by this upgrade within the Cost-Share Window under Section ##, this non-qualifying customer would pay to the Small DER Cost Sharing Fund a Cost-Share Fee pursuant to Section ##.	Oppose	This requirement would not guarantee that adequate funding will be available within the Small DER Cost Sharing Fund.
K.22	Insofar as proactive upgrades are associated with forecasted needs associated with identifiable customers, those customers shall be allocated costs consistent with existing CIAC policies, and an upgrade shall not be eligible for the proactive process.	Oppose	The Proactive Upgrade Framework is intended to address needs outside the traditional 5-year planning window. It is not clear why these upgrades should not be eligible for the proactive process.
K.23	[Utility's] existing CIAC policies include waiving service-transformer-related CIAC for customers with an EV who opt to participate in a managed charging program.	Oppose	Cost allocation is addressed in section A
K.24	For upgrades primarily intended to enable load growth by residential and small commercial customers, traditional cost allocation methods in a rate case shall apply. Specifically, the utility shall record costs from the upgrades in their respective FERC accounts and allocate costs with cost allocators from the utility's most recent rate case.	Oppose	Cost allocation is addressed in section A
K.25	For upgrades serving large commercial and industrial customers, proactive upgrades shall be tracked separately from other rate-base assets and their total cost allocated based on customer classes' aggregate contribution to the need for proactive upgrades.	Oppose	Cost allocation is addressed in section A

Requirement No.	Requirement	Position	Justification
K.26	If proactive upgrade costs are socialized to ratepayers, the utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small business by adjusting cost allocation within or among classes.	Oppose	Potential adverse bill impacts on under-resourced customers and small businesses should be addressed as a project selection criteria.
L. Capacity Reservation			
L.1 – L.6 are alternatives to one another.			
L.1	Capacity does not need to be reserved for a specific customer class.	Oppose	Capacity reservations need to be very carefully considered to be executed successfully. We support L.4 and L.4.a. However, if L.4 and L.4.a are not approved, then we would support L.1
OR			
L.2	Residential customers shall have priority for accessing proactive distribution capacity upgrades based on the percentage of upgrade costs allocated to residential rates.	Oppose	Reserving capacity on the distribution system based on how costs are allocated does not necessarily align with the customer needs of that part of the distribution system.
OR			
L.3	A percentage of the capacity of a proactive distribution upgrade may be reserved for under 40kW$_{ac}$ DG to facilitate more efficient queue processing through the Priority Queue, if the proposal demonstrates that based on the customer make-up of the feeder, existing customers will benefit from a capacity reservation.	Oppose	We do not support uniquely calculating a capacity reservation for each feeder. This will be difficult and burdensom to administer and track, and will further complicate the interconnection process for customers.
L.3.a	[Utility] shall propose a capacity reservation for under 40kW$_{ac}$ DG for each upgrade in a Proactive Upgrade Proposal with its filing.	Oppose	
L.3.b.	Small DG (less than 40kW$_{ac}$) shall continue to be able to use the Small DER Cost Sharing Fund for service transformer and secondary upgrades at the existing funding levels and fees consistent with Cost Sharing Program.	Oppose	
L.3.c.	[Utility] must seek PUC approval to implement this capacity reservation system and any specific Proactive Upgrade capacity reservation Proposal. If the utility's planning limit is invalidated, this agreement must be renegotiated.	Oppose	
OR			
L.4	[Utility] shall implement a system-wide capacity reservation for small DG to facilitate more efficient queue processing through the Priority Queue.	Support	We prefer L.4 and L.4.a if K.4 is approved.
L.4.a	Small DG (less than 40kW$_{ac}$) shall continue to be able to use the Small DER Cost Sharing Fund for service transformer and secondary upgrades at the existing funding levels and fees consistent with the Cost Sharing Program.	Support	We prefer L.4 and L.4.a if K.4 is approved.
OR			
L.5	[Utility] shall implement a system-wide capacity reservation for small DG in the Priority Queue to facilitate more efficient queue processing through the Priority Queue.	Oppose	We prefer L.5, L.5.a, and L.5.b if K.4 is not approved.
L.5.a	Small DG would be allowed to use the Small DER Cost Sharing Fund to help cover their pro-rata costs.	Oppose	We prefer L.5, L.5.a, and L.5.b if K.4 is not approved.
L.5.b	Once the mobilization threshold has been reached for a capacity upgrade, that triggers all subsequent DG projects to pay their pro-rata share, even if there is available capacity for Priority Queue applications within the capacity reservation.	Oppose	We prefer L.5, L.5.a, and L.5.b if K.4 is not approved.
OR			
L.6	[Utility] shall implement a capacity reservation system as follows:	Oppose	
L.6.a	**Generation:** Following a proactive DG hosting capacity upgrade, a minimum of 1 MW shall be reserved for the interconnection of systems below 40kW$_{ac}$. Where the installation of new DER systems larger than 40kW$_{ac}$ does not impose new constraints on the interconnection of 1 MW of new DG smaller than 40kW$_{ac}$, such systems can be allowed to proceed with interconnection.	Oppose	Specifying a 1 MW capacity reservation is arbitrary, and may be too much or too little depending on the rated capacity of the feeder or substation transformer. The capacity reservation should align with the planning standard.
L.6.b	**Load:** 25% [or another percentage to be discussed] of the capacity from proactive upgrades shall be reserved for residential and small C&I customers and shall not be made available to new load additions of total size in excess of 250kW$_{ac}$ [or another threshold to be discussed].	Oppose	The Company has a statutory obligation to serve load customers and there is no need for a capacity reservation for load customers.
L.6.c	**Reservation Waiver:** For locations where new adoption from residential and small C&I customers is not reasonably anticipated (e.g., on feeders serving exclusively industrial loads), load and generation capacity reservations for residential and small C&I customers such areas may be waived or reduced.	Oppose	
M. Reporting			
M.2 and M.3 are alternatives, otherwise any requirements may be adopted in any combination.			
M.1	[Utility] must file reports that include the following information and data to the greatest extent practicable. Where [utility] is not able to provide the required information, the Company shall explain why it is unable to do so. Such reports must be filed annually on November 1 as part of [utility's] Integrated Distribution Plan or Annual Update. Where applicable, [utility] must include data in spreadsheet (.xlsx) format. If [utility] also files a PDF version of spreadsheet data, it must be filed as an attachment in a separate document instead of being merged with the main report.	Support	
M.2	For projects where the cost share window has closed the utility shall no longer include them in the "all proactive upgrades" summary and may discontinue updates in the project-by-project reporting points.	Oppose	M.3 provides greater clarity on which reporting points may be discontinued.
OR			
M.3	For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.4 and M.5.	Support	
M.4	For all proactive upgrades –	Support	
M.5	By upgrade project –	Support	
M.6	DER additions (Fill out table for each completed project)	Support	
M.7	For each completed project, the current peak load, forecasted peak load, and any known load additions by load type (Fleet EV charging, DCFC fast charging, etc.) and customer class	Support	
M.8	A comparison of Load and DG added since project completion with the forecast from the Proactive Upgrade Proposal.	Support	
M.9	Any additional narrative information, by project or portfolio, on the status of the project, cost deviations from the approved amount, and any delays in implementation and the cause for the delays.	Support	
M.10	For any approved projects that did not proceed, an explanation of why and what the impact is on the overall program budget.	Support	
M.11	If the costs of previously approved proactive upgrades were not recovered within the cost-share window, [utility] shall provide a narrative explanation of why it was not able to recover the costs within the window. [Utility] shall also explain how it will improve its forecast or other procedures to avoid unnecessarily socializing costs.	Oppose	This will most likely be necessary for every proactive upgrade project. There will always be some amount of error in forecasts as it is impracticable to expect that any utility, individual, or organization will be able to precisely forecast customer adoption and behavior over 10-15 years.
M.12	For projects that were accelerated, delayed, or abandoned following Commission approval, [utility] shall discuss the impact of the ~~that~~ change ~~on total proactive grid upgrade costs, cost allocation, and benefit allocation~~.	Support as modified	

Requirement No.	Requirement	Position	Justification
1	Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by ~~Q2~~Q4 of ~~2027~~2026.	Support as modified	The timing of the Commission's decision needs to allow adequate time for any changes to be implemented for the Company's 2027 IDP. We prefer our modified 1 instead for this reason.
2	Phase 2 shall commence within 30 days of the Commission's written decision on Xcel Energy's 2025 Integrated Distribution Plan and follow the workgroup structure from Phase 1 with a goal of a Commission decision by Q3 of 2027.	Oppose	The timing of the Commission's decision needs to allow adequate time for any changes to be implemented for the Company's 2027 IDP. We prefer our modified 1 instead for this reason.
3	Coordination of the Proactive Distribution Upgrade Process with the Reactive-DER Cost Sharing Process:	Oppose	Deciding equipment size that considers forecasted needs when developing a reactively-driven project is already part of our existing business practice and should not be included in the proactive framework. The proactive upgrade framework should not include projects that have historically been completed and considered part of a utility's traditional planning processes, and should instead only include projects beyond existing planning practices as otherwise defined in this Framework. Further, these decisions must be made quickly due to the reactive nature of the need, and will not be able to wait until the next proactive upgrade proposal for consideration.
3a	Areas of the utility distribution system with existing interconnections queues are eligible for proactive upgrades beyond the reactive upgrades required to interconnect the systems in the existing queue.	Oppose	
3b	Proactive upgrades would be identified as the incremental investment and capacity relative to the reactive upgrade required at the given location to interconnect the systems in the existing queue.	Oppose	
3c	The proactive upgrades at such eligible locations must comply with all other aspects of the proactive upgrade framework	Oppose	
4	Forecasting for FTM generation to identify proactive upgrades, including whether to do a service territory wide analysis of optimal sites for front of the meter generation.	Support	We believe that 4 and 8 need to go together. See 8.
5	Flexible Interconnection.	Oppose	Flexible Interconnection is not an upgrade, it is a way of avoiding the need for an upgrade. Therefore, Flexible Interconnection is not relevant to the proactive upgrades framework.
6	Advanced cost allocation and cost recovery methodologies, including export tariffs.	Oppose	Cost allocation that deviates from established regulatory constructs & mechanisms would be difficult and burdensome to develop, implement and administer and could require changes to utility billing systems. It is also unclear why proactive upgrade projects would require different cost allocation methodologies than all other system investments.
7	Additional discussion on system wide capacity reservations.	Support	We believe that a system-wide capacity reservation is necessary to facilitate better Priority Queue processing through MN DIP, and to protect the ability for our retail customers to interconnect DER.
8	A full review of the Proactive Upgrade Framework to incorporate a process for identifying proactive infrastructure upgrades to enable hosting capacity for front of the meter distributed generation.	Support	We believe that 4 and 8 need to go together - improvements in forecasting for FTM generation through developer input is necessary to be able to adequately develop proposals for proactive upgrades that address FTM generation needs.

CERTIFICATE OF SERVICE

I, Joshua DePauw, 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/CI-24-318

Dated this 8th day of May 2025

/s/

____

Joshua DePauw
Regulatory Administrator

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39	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	24-318E002-CI-24-318

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40	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-318E002-CI-24-318
41	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-318E002-CI-24-318
42	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
43	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-318E002-CI-24-318
44	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	24-318E002-CI-24-318
45	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	24-318E002-CI-24-318
46	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	24-318E002-CI-24-318
47	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
48	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	24-318E002-CI-24-318
49	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	24-318E002-CI-24-318
50	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
51	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
52	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	24-318E002-CI-24-318
53	Paul	Schroeder	pauls@hourcar.org	HOURCAR		755 Prior Ave. N Suite 301D Saint Paul	Electronic Service		No	24-318E002-CI-24-318

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55104 United States				
54	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-318E002-CI-24-318
55	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	24-318E002-CI-24-318
56	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	24-318E002-CI-24-318
57	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	24-318E002-CI-24-318
58	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	24-318E002-CI-24-318
59	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
60	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
61	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	24-318E002-CI-24-318
62	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	24-318E002-CI-24-318
63	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	24-318E002-CI-24-318
64	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	24-318E002-CI-24-318
65	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	24-318E002-CI-24-318
66	Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St Saint Paul MN, 55102 United States	Electronic Service		No	24-318E002-CI-24-318

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67	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN, 55101 United States	Electronic Service		No	24-318E002-CI-24-318
68	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	24-318E002-CI-24-318
69	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	24-318E002-CI-24-318
70	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	24-318E002-CI-24-318
71	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	24-318E002-CI-24-318