COMMERCE DEPARTMENT

May 8, 2025

Will Seuffert
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: Comments of the Minnesota Department of Commerce
Docket No. E002/CI-24-318

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce (Department) in the following matter:

> *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy.*

The Notice was filed by the Public Utilities Commission (PUC or Commission) on April 7, 2025.

The Department recommends the Commission establish a framework for Proactive Distribution Grid Upgrades and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

RW, AZ, DD/ad
Attachments

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce

Docket No. E002/CI-24-318

I. INTRODUCTION

In its Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, the Commission agreed with parties that additional development was needed surrounding the topic of proactive distribution grid upgrades and the related cost allocation. To facilitate the development of the issues and solutions around proactive upgrades, the Commission delegated authority to the Executive Secretary to establish a stakeholder workgroup out of which a framework would be developed for approval by the Commission following a comment process. The Department participated in the workgroup and provided feedback throughout. These comments address the framework that came out of the stakeholder process, including the framework elements the Department recommends for the final, approved framework.

II. PROCEDURAL BACKGROUND

November 1, 2023	Xcel Energy filed its 2023 Integrated Distribution Plan.[1]
November 17, 2023	The Commission filed its Notice of Comment on Xcel's IDP. The notice included a question that stated: What guidance should the Commission give on budgets and cost allocation for distribution system upgrades to accommodate distributed energy resources (DER), including but not limited to: (a) Solar sited with customer load, (b) Solar sited in front of the meter, (c) Energy storage devices, (d) Electric Vehicles, (e) Space heating, water heating, and other electrification use cases, and (f) Proactive grid upgrades in anticipation of future DER growth.[2]
September 16, 2024	The Commission filed its Order Accepting Xcel's 2023 Integrated Distribution Plan and Modifying Reporting Requirements in Docket No. E002/M-23-452. The Commission delegated authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel.[3]

[1] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan,* Integrated Distribution Plan (filed in three parts), Xcel, November 1, 2023, Docket No. E002/M-23-452, (eDockets) 202311-200132-09.

[2] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan,* Notice of Comment Period, PUC, November 17, 2023, Docket No. E002/M-23-452, (eDockets) 202311-200579-01, at notice topic 17a-f.

[3] 2023 IDP Order at order point 14.

September 26, 2024	The Commission filed its Notice Soliciting Stakeholder Members in its new Proactive Upgrades docket (Docket No. E002/CI-24-318) with a deadline for indicating interest set for October 16, 2024.[4]
September 27, 2024	The Commission filed its Notice of Workgroup Processes and Soliciting Stakeholders to solicit stakeholder involvement in several workgroups, including the Proactive Upgrades workgroup, and to notice the opening of the corresponding dockets.[5]
October 25, 2024	The Commission filed its Notice Establishing Workgroup Membership denoting representation in the workgroup from many organizations including: the Department, the Office of the Attorney General (OAG), Xcel, the Environmental Law and Policy Center and Vote Solar, Dakota Electric, Fresh Energy, Minnesota Power, the Union of Concerned Scientists, and several others.[6]
November 2024 through March 2025	The Workgroup met five times to draft the framework components.
April 7, 2025	The Commission files the present Notice of Comment.[7]

Topic(s) open for comment:

- Should the Commission establish a framework for Proactive Distribution Grid Upgrades for Xcel Energy?
- Which requirements from the Draft Proactive Distribution Upgrade Framework, as outlined in Attachment A, should the Commission adopt?
  - A word document of the Draft Proactive Distribution Upgrade Framework is available upon request.
  - Staff requests commenters provide a list of all requirements supported by their organization in the comments.
  - If there are modifications to framework requirements, please include a redline of changed language.
- Does the Draft Framework address the following topics from the Commission's September 16, 2024, Order in Docket E002/M-23-452?

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[4] *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy,* Notice, PUC, September 26, 2024, Docket No. E002/CI-24-318, (eDockets) 20249-210502-01.
[5] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan,* Notice of Workgroup Processes and Soliciting Stakeholders, PUC, September 27, 2024, Docket No. E002/M-23-452, (eDockets) 20249-210530-01, at 2
[6] *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy,* Notice Establishing Workgroup Membership, PUC, Docket No. E002/CI-24-318, (eDockets) 202410-211320-01.
[7] *In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy,* Notice of Comment Period, PUC, Docket No. E002/CI-24-318, (eDockets) 20254-217295-01 (hereinafter "Notice").

  - How to allocate the costs of proactive upgrades.
  - How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.
  - If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.
  - How a proactive upgrade program would integrate with a utility's planned distribution investment programs.
  - How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.
  - How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.
  - Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).
- 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?
- Are there other issues or concerns related to this matter?

III. DEPARTMENT ANALYSIS

A. ESTABLISH A FRAMEWORK

The Department responds to the following notice topic:

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

In the Department's initial comments in the 2023 IDP, the Department took a skeptical stance on proactive distribution grid upgrades, but remained optimistic that forward-looking planning could provide benefits to Minnesota ratepayers. Specifically, the Department agreed with Xcel that the challenge of how best to enable additional DER—and the mechanism to fund necessary system upgrades—is a critical question over the coming years in various proceedings before the Commission.[8] The Department was most concerned about the large placeholder estimate for funding for proactive upgrades without additional analysis of the appropriateness and use of such funding as well as how topics like need, alternatives, timeline, type of project, and scope would be determined.[9]

Through participation in the stakeholder process, the Department concludes that the Proactive Distribution Grid Upgrades Framework (Framework) addresses many of these concerns and provides for additional stakeholder analysis through the workgroup's proposal for Phase 2. The Department recommends the Commission establish a framework for Proactive Distribution Grid Upgrades for Xcel Energy.

[8] In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Initial Comments, Department, March 1, 2024, Docket No. E002/M-23-452, (eDockets) 20243-204037-04, at 28.
[9] *Id.,* at 28-30.

B. FRAMEWORK REQUIREMENTS

The Department responds to the following notice topic:

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

The Department lists its recommended Framework requirements in Department Attachment A. In many sections of the Framework, there are several alternatives to choose from. The Department discusses its selections (where options exist) below.

B.1. Introduction

The Department supports requirement A.2. instead of A.1., as listed in Department Attachment A. The difference between A.1. and A.2. is quite small, however. A.1. suggests that proactive upgrades are required to meet state energy policy requirements and goals. Proactive upgrades are not required but are a tool to meet the state goals. Therefore, the Department prefers A.2.

The Department supports A.4. instead of A.5. The difference between the two options is minimal. However, the Department concludes that the specificity is unnecessary, regarding "minimizing the risk of stranded assets or projects," in A.5., as compared to "ensure they do not cause undue costs" in A.4. Such a rigorous review to avoid undue costs, as proposed in A.4, would necessarily avoid the stranded assets or projects specified in A.5.

The Department supports A.6. instead of A.7. The Department concludes the qualifier "to the extent reasonably possible" in A.7. is unnecessary.[10]

The Department supports A.8. instead of A.9. The Department concludes that qualifying the forecast inaccuracies to avoid as "unreasonable" is unnecessary.[11]

The Department supports A.12. instead of A.11. However, the difference between "when appropriate," and "whenever possible," is minimal. The Department could support A.11. or A.12.

B.2. Definitions

The Department supports B.7. instead of B.8. The inclusion of the last clause, "and is eligible for interconnection under the Minnesota Distributed Interconnection Procedures," is intended to recognize existing Minnesota procedure.[12]
The Department supports B.14. instead of B.15. The Department concludes that the discussion of prudency is unnecessary in the definition of a Proactive Upgrade Proposal.[13]

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[10] *Id*.
[11] *Id*.
[12] *Id*. at 3.
[13] *Id*. at 4.

In reference to the Definitions section as a whole, the Department notes that the section should reflect the terms utilized in the final accepted framework.

B.3. Process

The Department supports C.6. instead of C.5. or C.7. The Department concludes that the language, "Significant changes include but are not limited to scope changes to the project that would impact overall project cost," allows for sufficient flexibility for review, should there be a significant change that would impact overall project costs after approval.[14]

C.11. is discussed in Section D. of the Department's comments.

B.4. Baseline Information

There are no alternatives in Section D. Baseline Information.

B.5. Forecast

There are no alternatives in Section E. Forecast.

B.6. Potential Sites for Proactive Upgrades

There are no alternatives in Section F. Potential Sites for Proactive Upgrades.

B.7. Proactive Upgrade Proposal Evaluation Criteria

The Department supports G.15. instead of G.14. The Department concludes that the desired outcomes listed in G.14. do not match the desired outcomes of the proactive upgrade process described in the Introduction section of the Framework.[15]

B.8. Proposal for Non-Location Specific Proactive Measures

The Section H. Proposal for Non-Location Specific Proactive Measures is discussed in Section III.D. of the Department's comments.

B.9. Cost Recovery

The Department supports J.2. instead of J.1 or J.3. The Department concludes that J.2. is more explicit in its direction that a utility may request tracking in a regulatory asset or deferred accounting treatment, but the approval is ultimately the decision of the Commission.
The Department supports J.6. with redlines in its Department Attachment A. The Department concludes that allowing the cost-share window to remain open until the project is fully depreciated

[14] Notice, Attachment A at 5.
[15] Notice, Attachment A at 1.

allows for the costs to be assigned to cost-causers as much as possible. With the redlines, the Department concludes J.6. can be adopted without J.5.

The Department supports J.10. and J.11. The Department concludes that a cap is a necessary tool of ratepayer protection. The Department does not support J.12, which would allow funding to replenish without a Commission decision.

The Department supports J.13. and J.18. The Department concludes that an advance determination of prudency is unnecessary as presented in other framework options, but that a level of certainty is necessary for utility investment. J.13. and J.18. allow for an appropriate level of utility investment confidence, without disallowing rebuttal in a cost recovery proceeding if there is substantial evidence.

B.10. Cost Allocation

The Department supports the K.7. through K.12. package of options as well as items K.1. and K.26. The Department proposed this package of options during the workgroup process by grouping together some of its own proposals and the proposed items of other parties. The Department recommends several redlines to the package of items. The Department also recommends adding subtitles to delineate the Cost Allocation section into a section relating to load and a section relating to generation interconnection.

The redline in K.1. adds the word "retroactive" to ensure that a change in distribution planning or other utility standards is not retroactively applied to completed projects.

K.26. is amended to remove the language, "by adjusting cost allocation within or among classes" to avoid shifting costs to classes that are not cost causers.[16] The Department also adds, "to the extent that," to the beginning of the Framework option to clarify that socializing costs to ratepayers is the last option for cost allocation.[17]

K.7. and K.10. are revised to remove CIAC to reflect the definition of "cost share fee" as defined in the Framework.

K.8. is modified to simplify the language pertaining to allocating the costs of commercial and industrial driven upgrades specifically to those classes.

B.11. Capacity Reservation

Section L. Capacity Reservation is discussed in section D. of the Department's comments.

B.12. Reporting

[16] Department Attachment A at K.26.
[17] *Id*.

The Department supports all the requirements presented in section M. Reporting. However, one modification is needed at M.3., most likely due to a numbering error while the workgroup was iterating on the Framework. M.3. should reference the tables provided at M.5. and M.6. This change is noted in Department Attachment A.

B.13. Final Recommendation

The Department recommends the Commission adopt the recommendations as proposed in Department Attachment A.

C. ORDER REQUIREMENTS

The Department responds to the following notice topic:

> Does the Draft Framework address the following topics from the Commission's September 16, 2024, Order in Docket E002/M-23-452?
>
> Each of the subsequent subheadings in this section contain the requirements of each sub-requirement of the Commission's notice topic, and are addressed in order.

C.1. How to allocate the costs of proactive upgrades.

Allocating the costs of proactive electric grid upgrades can involve a combination of potential approaches, including assigning costs to specific generators or load customers, sharing costs across projects or regions, and using standardized, sometimes pro-rata, methods. Special consideration should be given to the methods for allocating costs of proactive upgrades, since the goal of such cost allocation measures is to ensure that the burden of upgrade costs is distributed fairly among those who benefit from the improved grid.[18]

The Framework addresses Cost Allocation at Section K.[19] Furthermore, to allow for additional development on Cost Allocation and the examination of additional, more advanced methodologies, the Workgroup proposes the following discussion topic for Phase 2:

> 6. Advanced cost allocation and cost recovery methodologies, including export tariffs.[20]

The Department concludes that the Framework addresses Order Point 14(d)(i) of the Commission's 2023 IDP Order.[21]

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[18] US Department of Energy, Interconnection Innovation E-Xchange (June 7, 2023). *Queue Management and Cost Allocation*. pp. 10-33. Retrieved from: https://www.esig.energy/wiki-main-page/a-proactive-approach-for-accommodating-high-penetrations-of-distributed-generation-resources/#:~:text=Optimal%20Distribution%20System%20Planning,and%20are%20discussed%20further%20below.
[19] Notice, Attachment A at 13.
[20] Notice, Attachment B at 1.
[21] 2023 IDP Order at 25.

C.2. How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory.

To ensure proactive utility upgrades are equitably distributed, regulators should consider policies that relate to the prioritization of projects, such as those projects benefiting underserved areas or underserved customers, to meet established policy goals. Consideration should also be given to establishing policies related to the distribution of proactive upgrades in a way that ensures costs and benefits are fairly distributed and involves stakeholders in planning to address specific community needs.[22]

The Framework addresses the equitable distribution of proactive upgrades projects throughout. Most notably, the following components address the Commission's order point:

> 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.[23]
>
> F.4. and G.10. 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).[24]

The Department concludes that the Framework addresses Order Point 14(d)(ii) of the Commission's 2023 IDP Order.[25]

C.3. If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes.

The Framework addresses capacity reservation at Section L.[26] The Workgroup also proposes the following discussion topic for the scope of Phase 2:

> 7. Additional discussion on system wide capacity reservations.[27]

The Department concludes the Framework addresses Order Point 14(d)(iii) of the Commission's 2023 IDP Order.[28]

C.4. How a proactive upgrade program would integrate with a utility's planned distribution investment programs.

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[22] US Department of Energy, "Proactive Regulatory Approaches to Electrification and Load Growth" Workshop slides, Jessica A. Shipley, page 11. (July 10-11, 2024).
[23] Notice, Attachment A at 1.
[24] Notice, Attachment A at 8 and 10.
[25] 2023 IDP Order at 25.
[26] Notice, Attachment A at 17-18.
[27] Notice, Attachment B at 1.
[28] 2023 IDP Order, at 25.

The Framework discusses integration of the proactive upgrades process with the utility's existing distribution planning processes in several instances throughout. For example, proactive upgrade proposals are intended to be proposed upgrades that are needed outside of the utility's traditional planning cycle, as evidenced by the following framework components:

> B.16 Proactive Distribution Upgrade: a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle.[29]
>
> 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.[30]

Furthermore, the integration of the proactive process contrasts with the standard process by the inclusion of the following component:

> 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.[31]

The Department concludes the Framework addresses Order Point 14(d)(iv) of the Commission's 2023 IDP Order.[32]

> *C.5. How a utility's other capacity programs and changes to distribution standards impact available hosting capacity.*

Hosting capacity is discussed in several instances throughout the Framework. For example, the following component discusses the forecasts utilized to determine the need for upgrades:

> 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.[33]

Furthermore, in the Proposal Evaluation Criteria section, the utility is tasked with providing the following as part of its filing for each proactive distribution upgrade proposal:

> 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.[34]

[29] Notice, Attachment A at 4.
[30] Notice, Attachment A at 8.
[31] Notice, Attachment A at 10.
[32] 2023 IDP Order, at 25.
[33] Notice, Attachment A at 8.
[34] Notice, Attachment A at 10.

In reference to cost allocation, the Framework includes the following component to discuss hosting capacity:

> 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.

The Department concludes that the Framework addresses Order Point 14(d)(v) of the Commission's 2023 IDP Order.[35]

> *C.6. How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption.*

Section E of the Framework addresses the Forecast, its assumptions, and how a proposed project must be based on a forecasted need within a specified time frame. Section E includes, among others, the following components:

> E.1 [Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and electrification 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.[36]

Additionally, there are many other mentions of the forecasted need for proactive upgrade proposals. Another notable example of this discussion is in several of the components listed in the Potential Sites for Proactive Upgrades section:

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

[35] 2023 IDP Order at 25.
[36] Notice, Attachment A at 7-8.

> F.6.f Magnitude of forecasted growth (load or generation) and capacity gap 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.[37]

The Workgroup also proposes the following forecasting related component for inclusion in Phase 2:

> 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.[38]

The Department concludes that the Framework addresses Order Point 14(d)(vi) of the Commission's 2023 IDP Order.[39]

> *C.7. Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).*

CIAC is discussed in the iterations of Section K: Cost Allocation.[40] For example, the following component addresses CIAC:

> 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.
>
> > 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.[41]

Additionally, the Workgroup proposes the following discussion topics for Phase 2, which may result in changes to a utility's service policy provisions:[42]

> 5. Flexible Interconnection.

[37] Notice, Attachment A at 8.
[38] Notice, Attachment B at 1.
[39] 2023 IDP Order, at 25.
[40] Notice, Attachment A at 14-15.
[41] *Id.*
[42] Notice, Attachment B at 1.

> 6. Advanced cost allocation and cost recovery methodologies, including export tariffs.

The Department concludes that the Framework addresses Order Point 14(d)(vii) of the Commission's 2023 IDP Order.[43]

D. PHASE 2

The Department responds to the following notice topic:

> 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?

The topics proposed for Phase 2 will build on the Framework compiled in the first phase of the workgroup and will create opportunities for stakeholders to continue to inform the Proactive Upgrades process going forward.

The subsection of the Framework entitled, "Coordination with distributed generation developers," requires the formation of a new stakeholder engagement group to facilitate utility-developer coordination on long term planning topics.[44] The Department supports utility-developer coordination within the proactive upgrades process, but is hesitant to propose another stakeholder process and require attendance by parties when there may be a more efficient venue or process that could be explored, if time allows. The Department recommends the Framework subsection entitled "Coordination with distributed generation developers" be removed from the Framework and moved to Phase 2 of the process. The recommendation is reflected in Department Attachment B.

Additionally, the section of the Framework entitled "Proposal for Non-Location Specific Proactive Measures," allows for the proposal of programmatic investment proposals that affect a variety of locations that may shift over time.[45] It is unclear what a proposal under this framework section could include and what guardrails need to be put in place to evaluate the proposal. The Department recommends the Framework section entitled "Proposal for Non-Location Specific Proactive Measures," be removed from the framework and moved to Phase 2 of the process. The recommendation is reflected in Department Attachment B.

Phase 2 of the workgroup also proposes to discuss advanced cost recovery methodologies, including export tariffs, and system wide capacity reservations.[46] The "Capacity Reservation" section of the Framework, as noticed, contains numerous competing options.[47] The Department concludes that additional time may allow for stakeholders to continue to develop a recommendation (or lessen the

[43] 2023 IDP Order at 25.
[44] Notice, Attachment A at 6.
[45] Notice, Attachment A at 11.
[46] Notice, Attachment B, at 1.
[47] Notice, Attachment A, at 17-18

number of options to choose from) regarding a potential capacity reservation. Moreover, additional discussion of capacity reservations would merely be an expansion of the topics proposed for Phase 2 by the workgroup. The Department recommends the section entitled "Capacity Reservation" be removed from the Framework and moved to Phase 2 of the process. The recommendation is reflected in Department Attachment B.

The Department recommends that the Commission establish Phase 2 of the Proactive Distribution Grid Upgrade Proceeding, as proposed in Department Attachment B, to enable the parties to continue making contributions through information and recommendations to be provided to the Commission. While the Commission's workload on other dockets may eventually determine which of the two proposed timing alternatives is the more viable option, the Department currently recommends that the Commission adopt Alternative 1 for the timing of Phase 2 of the Proactive Distribution Grid Upgrade.

E. OTHER CONCERNS

The Department responds to the following notice topic:

> Are there other issues or concerns related to this matter?

The Department raises two additional considerations regarding the Framework. First, the voluntary nature of the Framework means that there is a potential for no proactive projects to be presented. If the Framework is deemed too onerous for a utility, or if the utility believes it can obtain more income from the status quo, the utility may choose not to file a plan. The Department is skeptical of potential benefits of proactive upgrades, however if a utility expects large system growth, there is a clear benefit to size the distribution system to meet a longer-term growth expectation (beyond the standard five years) to avoid multiple, repetitive upgrades. For this reason, it is important to require utilities to evaluate their systems for proactive upgrades, regardless of whether or not the utility decides to voluntarily file a plan. The Framework component E.4 addresses the Department's concern, but it is only required if a utility files a Proactive Upgrade Plan. The Department modifies E.4 to include the requirement for all IDPs:

The Department recommends the Commission order a new filing requirement to the integrated distribution plan of all utilities for which proactive planning is approved:

- Forecast results for generation and peak loads at the feeder/substation level for all locations that have a potential proactive upgrade need, as well as the standard reactive upgrade capacity upgrade.

Second, the Department is concerned about the overlap in scope between the Proactive and Reactive workgroups. Laws of Minn. 2024, ch. 126, art. 6, sec. 53(a)(5) states that the Commission must develop tariff standards that: "establish a minimum proportion of the total upgrade cost that a utility must receive from one or more distributed generation facilities before initiating constructing an upgrade." By definition, this requirement includes a proactive DER upgrade component. The Framework similarly includes a large proactive DER component. When given the choice between a project with advanced

payment for a portion of the total upgrade cost and one with no advanced payment, the Department will always recommend maximizing the share of advanced payment in order to minimize the risk that ratepayers subsidize DER generation upgrade costs. While the Department recognizes that there may be situations in which the Framework can provide different options in scope that may not be possible to address in the Reactive workgroup, the default option should always be to propose a proactive DER project within the Reactive framework. Budget limitations are not an appropriate justification to pursue projects within the Framework because the Commission can modify the Reactive framework cost cap.[48]

The Department does not advocate for the removal of proactive DER projects from the Framework, but rather urges caution for the approval of fully proactive DER projects. There are potential situations in which the Framework, or the Phase 2 Framework, may be better suited to offer projects that may not work well under a purely reactive DER framework. These situations may include, but are not limited to:

A. Smaller-scale, localized projects such as tap-line reconductoring;[49]
B. Projects where the majority of beneficiaries are expected in the residential rate class;[50] and
C. Projects where significant load and DER co-benefits are expected.

The Department does not offer the above situations as automatic pre-qualification for the Framework, but rather offers these examples as illustrative of situations in which an argument could be made to potentially include a project in the Framework. The decision to include a DER project in the Framework should rather be made on a case-by-case basis if a utility decides not to pursue a project in the Reactive framework.

The Department recommends that utilities must justify why all distributed energy resource projects proposed under the Proactive Upgrade Framework cannot be pursued within the Reactive Framework.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of the Proactive Upgrades Workgroup's proposed framework and the information in the record, the Department has prepared recommendations, which are provided below. The recommendations correspond to the subheadings of Section III above.

A. ESTABLISH A FRAMEWORK

- The Department recommends the Commission establish a framework for Proactive Distribution Grid Upgrades for Xcel Energy.

[48] See Laws of Minn. 2024, ch. 126, art. 6, sec. 53(a)(8). While this section pertains to the Commission's requirement to establish a cost cap, the law does not prevent the Commission from modifying the cost cap.
[49] For example, if the Reactive workgroup does not include tap lines.
[50] If a pro-rata cost share is determined to be unreasonable for the residential rate class.

B. FRAMEWORK REQUIREMENTS

- The Department recommends the Commission adopt the recommendations as proposed in Department Attachment A.

C. ORDER REQUIREMENTS

- The Department concludes the Framework has met the Order Requirements of its 2023 IDP Order.

D. PHASE 2

- The Department recommends that the Commission establish Phase 2 of the Proactive Distribution Grid Upgrade Proceeding, as proposed in Department Attachment B.

- The Department recommends that the Commission adopt alternative 1 for the timing of Phase 2.

E. OTHER CONCERNS

- The Department recommends the Commission order a new filing requirement to the integrated distribution plan of all utilities for which proactive planning is approved:

    - Forecast results for generation and peak loads at the feeder/substation level for all locations that have a potential proactive upgrade need, as well as the standard reactive upgrade capacity upgrade.

- The Department recommends that utilities must justify why all distributed energy resource projects proposed under the Proactive Upgrade Framework cannot be pursued within the Reactive Framework.

ATTACHMENT A

Department Recommended Framework Requirements	
Item	Language
Introduction	
A.2. Includes redlines from PUC notice	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.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.
A.6.	Maximize the benefits to the distribution system while minimizing the costs.
A.8.	Limit cost impacts to ratepayers from forecast inaccuracies.
A.10.	Limit deviations from traditional cost allocation and recovery processes to the extent possible.
A.12. Includes redlines from PUC notice	Costs should be allocated to the customers or classes causing the costs, ~~when appropriate~~ whenever possible.
A.13.	If cost-causation cannot be determined, costs should be allocated according to the distribution of benefits.
Definitions	
B.2. Includes redline from PUC Notice	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.
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.
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.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.
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.14.	Proactive Upgrade Proposal: one or more Proactive Distribution Upgrades submitted for Commission approval under the Proactive Distribution Upgrade Framework.
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 40kWac or less as detailed on [tariff sheet 10-81.4].
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.

ATTACHMENT A

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.6. Includes redlines from PUC Notice	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.
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 unresolved 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].

Baseline Information	
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.
Forecast	
E.1.	[Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and electrification 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.
Potential Sites for Proactive Upgrades	
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.

Proactive Upgrade Proposal Evaluation Criteria	
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.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
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.
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.
Cost Recovery	
Cost Recovery Mechanism	
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.
J.4	All cost-share fees collected from Cost-Share Customers shall be returned to ratepayers as an offset to proactive upgrade capital investments.
Cost Share Window	

J.6 Includes Department Redlines	~~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, t~~ The cost-share window for that upgrade shall remain open until the upgrade is fully depreciated to help mitigate risks to ratepayers.
Cost Cap	
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.
J.11	Capital expenditures that have been offset by cost-share fees do not count against the cap.
Prudency Review	
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.
J.18.	An interested person may submit substantial evidence to rebut the Proactive Upgrade Proposal findings and conclusions in a cost recovery proceeding.
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 retroactive change in cost-sharing responsibility.
K.26. Includes Department redlines	To the extent that proactive upgrade costs are socialized to ratepayers, the utility shall identify and mitigate adverse bill impacts on under-resourced customers and/or small businesses ~~by adjusting cost allocation within or among classes.~~
Subsection: Cost Allocation between Customers Adding New Load and Rate Payers	
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~~ via a cost share fee. K.7.a ~~The proactive share of the eligible CIAC~~ Cost-share fee for small load additions from the residential class should be structured similarly to the 40 kW and under small DER cost share.
K.8.	For proactive upgrade projects primarily serving large commercial and industrial customers, proactive upgrade costs shall be tracked separately from other rate-base assets and ~~their total cost~~ allocated ~~based on large commercial and~~

Includes Department Redlines	~~industrial's aggregate contribution to need for proactive upgrade.~~ to the large commercial and industrial classes contributing to the need for the upgrade.
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.
K.10.	Insofar as proactive upgrade costs are recovered from customers through ~~CIAC~~ cost-share fees, 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.
Subsection: Cost Allocation between Customers Interconnecting Generation and Rate Payers	
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. K.11.a Fees shall continue to be collected beyond the original date of the forecasted need if capacity remains 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. K.11.c The existing small DER cost sharing program may be used to fund the upgrade fee.
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.
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. Includes redlines from PUC Notice and Dept	For projects where the cost-share window has closed, the utility may discontinue updates in the project-by-project reporting points under M.5 and M.6.

redlines in green	
M.4.	Support M.4. Table
M.5.	Support M.5. Table
M.6.	Support M.6. Table
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
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.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.
M.12	For projects that were accelerated, delayed, or abandoned following Commission approval, [utility] shall discuss the impact of that change on total proactive grid upgrade costs, cost allocation, and benefit allocation.

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 of 2027.

Topics to be developed in Phase 2 shall include but are not limited to:

2. Coordination of the Proactive Distribution Upgrade Process with the Reactive-DER Cost Sharing Process:

    a. 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.

    b. 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.

    c. The proactive upgrades at such eligible locations must comply with all other aspects of the proactive upgrade framework

3. 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.

4. Flexible Interconnection.

5. Advanced cost allocation and cost recovery methodologies, including export tariffs.

6. [Department Redlines] Additional discussion on capacity reservations, to include system wide capacity reservations.

7. 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.

8. [Department recommended move from Phase 1 to Phase 2] Coordination with distributed generation developers:[1]

    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.

    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.

    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.

    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.

    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.

    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.

[1] Notice, Attachment A at 6.

9. [Department recommended move from Phase 1 to Phase 2] Proposal for Non-Location Specific Proactive Measures:[2]
    a. 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.

    b. 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.

[2] Notice, Attachment A at 11

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E002/CI-24-318

Dated this **8th** day of **May 2025**

/s/Sharon Ferguson

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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

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						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