COMMERCE DEPARTMENT

March 1, 2024 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Xcel Energy 2023 Integrated Distribution Plan
Docket No. E002/M-23-452

Dear Mr. Seuffert:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

In the Matter of Xcel Energy's 2023 Integrated Distribution Plan

Xcel Energy's 2023 Integrated Distribution Plan (IDP) were filed on November 1, 2023, by Amber Hedlund, Manager, Regulatory Project Management for Xcel Energy.

The Department makes recommendations and requests below and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Louise Miltich
Assistant Commissioner of Energy Regulatory Analysis

LM/ad
Attachment

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E002/M-23-452

CONTENTS

I. INTRODUCTION

The Department provides the following comments on Xcel's 2023 Integrated Distribution Plan (IDP). Through these comments, the Department responds to the Notice of Comment (Notice) issued by the Commission on November 17, 2023.[1]

While the Department finds that Xcel's IDP is largely compliant with filing requirements, the Department also identifies areas in which the IDP that could be improved and offers recommendations (in bold, italicized text) for remedying them. The Department will provide a final recommendation regarding whether the Commission should accept Xcel's 2023 IDP in reply comments once the Department reviews additional information from Xcel and has the opportunity to consider stakeholder input.

II. PROCEDURAL HISTORY

On November 1, 2023, Northern States Power Company d/b/a Xcel Energy (Xcel Energy or the Company) filed its 2023 IDP and Transportation Electrification Plan (TEP) in Docket No. E002/M-23-452.[2] This is the first time that Xcel Energy has filed its TEP as part of its IDP filing.

On November 17, 2023, the Commission issued a Notice of Comment period with two separate comment periods. The first comment period, addressed in prior comments, corresponds to Xcel's TEP and includes Notice Topics 1 through 13. The second comment period, addressed in these comments, corresponds to Xcel's IDP and includes Notice Topics 14 through 24. The following notice topics are addressed in these comments:

14. Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan (IDP)?
15. Did Xcel Energy adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice? Is additional information necessary for improved clarity?
16. Feedback, comments, and recommendations on the following areas of Xcel's IDP:
    a. Non-Wires Alternative Analysis
    b. Grid modernization plans, including but not limited to a Distributed Energy Resource Management System (DERMS), Virtual Power Plants (VPP), Integrated Volt-Var Optimization (IVVO), and Distributed Intelligence (DI)
    c. Forecasted distribution budget
    d. Initial LoadSEER forecasting results and methodology
    e. Planned Net Load (PNL) methodology and 15% Dependability Factor

[1] *Notice of Comment – In the Matter of Xcel Energy's 2023 Integrated Distribution Plan, Docket No. E-002/M-23-452*, November 17, 2023.
[2] *2023 Integrated Distribution System Plan, Northern States Power Company, d/b/a Xcel Energy, Docket No. E002/M-23-452*, November 1, 2023.

17. 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
    f. Proactive grid upgrades in anticipation of future DER growth
18. What decisions should the Commission make in the IDP to provide Xcel guidance in aligning distribution spending with forthcoming rate cases?
19. Should the Commission require cost-benefit analysis for discretionary distribution system investments?
20. Should the Commission discontinue IDP Requirement 3.A.9 as requested by Xcel?
21. Should the Commission revise the IDP Filing Requirements for Xcel Energy to remove the requirement that financial information be reported in IDP-specific categories, as requested by Xcel?
22. What should the Commission consider or address related to enhancing the resilience of the distribution system within Xcel's IDP?
23. Has Xcel Energy appropriately discussed its plans to maximize the benefits of the *Inflation Reduction Act* (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22-624?
24. Other areas of Xcel's IDP or TEP not listed above, along with any other issues or concerns related to this matter.

Below are the comments of the Department regarding Xcel's IDP and the Commission's Notice Topics 14 through 24.

III. DEPARTMENT ANALYSIS

OVERVIEW OF COMMENTS

The initial comments provided by the Department address Notice Topics 14-24. Recommendations are offered in the corresponding sections and are summarized at the conclusion of this filing.

For reasons of organization and clarity, these comments do not perfectly follow the sequence of topics in the Notice of Comment. The order of these comments is presented below:

A. IDP Compliance with Filing Requirements and Recommendations Concerning Acceptance (Notice Topic 14 and Notice Topic 15)
B. Xcel's Distribution Budget and Related Issues (Notice Topic 16.C, Notice Topic 18, and Notice Topic 21)

C. Budgets and Cost Allocation for Distribution System Upgrades to Accommodate Distributed Energy Resources (DER) (Notice Topic 17(A-F))
D. Grid Modernization: Required Information and Cost-Benefit Analysis (Notice Topic 16.B and Notice Topic 19)
E. Non-Wires Alternatives Analysis (Notice Topic 16.A)
F. Resiliency Performance Tracking and Microgrids (Notice Topic 22)
G. Initial LoadSEER Forecasting Results and Methodology (Notice Topic 16.D)
H. Planned Net Load (PNL) Methodology and 15% Dependability Factor (Notice Topic 16.E)
I. Modification of IDP Filing Requirements (Notice Topic 20)
J. The Inflation Reduction Act and Utility Planning and Benefits (IDP Notice Topic 23)
K. On the Timing and Synchronization of IDPs With Other Proceedings (Notice Topic 24)

A. IDP COMPLIANCE WITH FILING REQUIREMENTS AND RECOMMENDATIONS CONCERNING ACCEPTANCE

Notice Topic 14: Should the Commission accept or reject Xcel Energy's Integrated Distribution Plan?

Notice Topic 15: Did Xcel Energy adequately address the Commission's IDP filing requirements and prior orders, as outlined in Attachment A to this Notice? is additional information necessary for improved clarity?

Xcel has provided a matrix in Attachment B to its IDP with the IDP filing requirements, the requirements imposed on Xcel's 2023 IDP by previous Commission Orders and statutes, and the location within the IDP where information related to those requirements can be found.[3] The Department is including Xcel's matrix of filing requirements and their location in the IDP as Attachment A with these comments.

The Department's review of Xcel's IDP begins at a threshold question: did Xcel provide information and analyses required by the Commission's IDP filing requirements and previous Commission Orders? The Department reviewed Xcel's compliance matrix and determined that the references provided to the contents within the IDP are appropriate. Further, at first pass, it does appear that Xcel has mostly addressed each of the IDP filing requirements, Commission Orders, and statutes. Moreover, as required by the Notice, where Xcel did not include the required information, the Company generally provided an explanation of why that information was not included in the filing. However, in several instances, the information provided by Xcel was insufficient; in response to certain requirements, the Company provided information not requested in place of requested information, or the Company did not address the filing requirement or Notice Topic. Specific examples are indicated throughout the Department's comments below.

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[3] *Integrated Distribution Plan, In the Matter of Xcel Energy's 2023 Integrated Distribution System Plan*, *Docket No. E002/M-23-452,* November 1, 2023. *Hereinafter* 2023 IDP. Attachment B.

Throughout these comments the Department has also identified topics and Order Points where additional information would improve the ability to meaningfully analyze the IDP.

The Department will provide a final recommendation regarding whether the Commission should accept Xcel's 2023 IDP in reply comments once the Department reviews additional information from Xcel and has had the opportunity to review stakeholder input.

i. Compliance with Specific Grid Modernization Filing Requirements

Xcel's IDP is subject to multiple filing requirements concerning grid modernization information. Most substantively, Xcel is obligated to provide detail about planned grid modernization investments expected to occur in the next five years in the "5-Year Action Plan" that is a part of the mandated "Long-Term Distribution System Modernization and Infrastructure Investment Plan."

Per the Commission's IDP filing requirements, the 5-Year Action Plan "should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5 years."[4] The filing requirements also establish the need for a clear statement of the objectives of individual projects and detailed alternatives analysis.[5] Further, the Commission requires that for each grid modernization project included in the 5-Year Action Plan, "Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel should provide all information used to support its analysis."[6] Discussion of grid modernization filing requirements is provided in Section 0.

The Department finds that Xcel has not met its obligations to provide detailed information about near-term grid modernization investments as a part of the 5-year Action Plan. Though Xcel anticipates moving forward with DI, DERMS, and potentially, a successor ADMS system within the five-year window of the Action Plan, the Company has not provided a sufficiently detailed evaluation of these investments, and it has neglected to provide cost-benefit analyses—a key omission.[7]

In Xcel's view, the obligation to provide detailed information on investment costs and benefits appears to only apply when cost recovery is being requested.[8] Notwithstanding that the IDP may contain requests for certification for grid modernization projects only and not for investment cost recovery, the Department does not agree with Xcel's assessment, which seems to be contradicted by the plain language of the Commission's IDP filing requirements.

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[4] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2).
[5] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2.c).
[6] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2.k).
[7] 2023 IDP, Appendix C at pages 5-6 and, Figure C at page 12.
[8] Attachment B, Xcel Energy. *Response to Information Request No. 18, Topic: Distributed Intelligence (DI).* (February 15, 2024). Attachment B provides Xcel's public responses to all Department Information Requests.

Xcel also appears to believe that not having sufficiently developed plans for near-term investments relieves the Company of the need to comply with Action Plan requirements.[9] In the Department's view, however, Xcel's IDP should include cost and benefit details and other required information on investments anticipated within the next five years to the maximum extent possible. Otherwise, there is a risk that the Company will move ahead with these investments and cost recovery requests without subjecting them to stakeholder and Commission review and without comprehensive system planning information that is not covered in other regulatory proceedings. The Department also notes that Xcel has not complied with certain additional filing requirements relating to grid modernization that have been promulgated through recent Commission Orders. These issues of noncompliance are discussed in detail in Section 0.

The Department recommends that the Commission direct Xcel to refile Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects. Xcel should further be required to make any other necessary modifications to its IDP to reflect the necessary changes to Appendix C.

B. XCEL'S DISTRIBUTION BUDGET AND RELATED ISSUES

Notice Topic 16.C: Feedback, comments, and recommendations on the following areas of Xcel's IDP: Forecasted distribution budget

Notice Topic 18: What decisions should the Commission make in the IDP to provide Xcel guidance in aligning distribution spending with forthcoming rate cases?

Notice Topic 21: Should the Commission revise the IDP filing requirements for Xcel Energy to remove the requirement that financial information be reported in IDP-specific categories, as requested by Xcel?

i. Total Distribution Budget

The Commission requested feedback, comments, and recommendations on Xcel's forecasted distribution budget. Xcel's 2021 IDP projected total distribution spending of approximately $3.0 billion between 2021 and 2026.[10] Xcel's 2022 Compliance Filing projected total distribution system spending of approximately $3.9 billion between 2022 and 2027.[11] Xcel's 2023 IDP increased that projection to over $4.2 billion between 2023 and 2028,[12] representing noticeable changes in projected spending.

Table 1 provides a high-level overview of the projected spending levels Xcel provided in its 2021 IDP, 2022 Compliance Filing, and 2023 IDP, organized by the IDP Budget Categories required by IDP Filing Requirement 3.A.29. IDP Filing Requirement 3.A.29 requires Xcel to provide information on "[p]lanned

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[9] See, for example, 2023 IDP, Appendix C at pages 5-6.
[10] 2021 IDP at page 18.
[11] *Compliance – Annual Update, In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan*, *Docket No. E002/M-21-694* (November 1, 2022). *Hereinafter* 2022 Compliance Filing. Table 1 at page 12.
[12] IDP at page 21.

distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic[al] spending."[13] There are nine IDP Budget Categories, which are listed in the table. The Department has combined the "EV Programs" budget category with the "Grid Modernization and Pilot Projects" budget category in the following tables to facilitate comparisons to prior IDPs. As Xcel noted in its filing, this is the first IDP with the EV Programs provided as a separate category.[14]

Table 1. Comparison of Xcel Distribution System Spending Projections: 2021 IDP, 2022 Compliance Filing, and 2023 IDP

	2021 IDP (2021 - 2026)	Compliance Filing (2022 - 2027)		2023 IDP (2023 - 2028)	
IDP Budget Category	*Spending (Millions)*	*Spending (Millions)*	*Δ*	*Spending (Millions)*	*Δ vs Compliance Filing*
Age-Related Replacements and Asset Renewal	$ 971.30	$ 1,180.40	**$ 209.10**	$ 1,272.20	**$ 91.80**
New Customer Projects and New Revenue	$ 237.40	$ 274.20	**$ 36.80**	$ 296.40	**$ 22.20**
System Expansion or Upgrades for Capacity	$ 273.70	$ 546.50	**$ 272.80**	$ 770.20	**$ 223.70**
Projects related to Local (or other) Government-Requirements	$ 210.10	$ 208.40	**$ (1.70)**	$ 231.50	**$ 23.10**
System Expansion or Upgrades for Reliability and Power Quality	$ 239.20	$ 250.80	**$ 11.60**	$ 740.60	**$ 489.80**
Other	$ 286.60	$ 436.80	**$ 150.20**	$ 374.60	**$ (62.20)**
Metering	$ 21.90	$ 30.80	**$ 8.90**	$ 27.60	**$ (3.20)**
Grid Modernization and Pilot Projects (including EV Programs)	$ 763.30	$ 930.60	**$ 167.30**	$ 514.90	**$ (415.70)**
Total Spending	**$ 3,003.50**	**$ 3,858.50**	**$ 855.00**	**$ 4,228.00**	**$ 369.50**

Source: 2021 IDP at 18, 2022 Compliance Filing at 12, 2023 IDP at 21.

This table calculates the difference in projected spending between the 2021 IDP and the 2022 Compliance Filing, and the difference in spending between the 2022 Compliance Filing and the 2023 IDP.

These filings were made a year apart from one another (November 1, 2021, November 1, 2022, and November 1, 2023) and overall distribution system spending projections increased from approximately $3.0 billion to over $4.2 billion, a 40 percent increase. The IDP Budget Categories of "Age-Related

[13] IDP Filing Requirement 3.A.29.
[14] IDP Appendix D at page 6.

Replacement and Asset Renewal", "System Expansion or Upgrades for Capacity", and "System Expansion or Upgrades for Reliability and Power Quality" are the main drivers of the spending increase: accounting for projected increases of $91.8 million (8 percent), $223.7 million (41 percent), and $489.8 million (195 percent), respectively, since the 2022 Compliance Filing.

There is a notable increase, and subsequent decrease, in projected spending for the IDP Budget Category "Grid Modernization and Pilot Projects (including EV Programs)," accounting for a total decrease in projected spending of $415.7 million (-45 percent) from the 2022 Compliance Filing. The Department notes that the 2022 Compliance Filing included Xcel's Clean Transportation Portfolio proposed in Docket No. E002/M-22-432, which was subsequently withdrawn. The 2022 Compliance Filing included more than $500 million for EV Programs.[15] In contrast, the 2023 IDP includes $147 million on spending for EV Programs in the 2023 through 2028 forecast.[16] Thus, the reduction in the budget for EV Programs explains most of the forecast variation in the combined IDP Budget Category "Grid Modernization and Pilot Projects (including EV Programs)" in Table 1.

While Table 1 shows increases in total projected spending in each subsequent filing, it is important to note that this is not an apples-to-apples comparison given the periods analyzed in each filing (e.g., the 2021 IDP period covers years 2021 through 2026, whereas the 2023 IDP period covers years 2023 through 2028).

To obtain a better apples-to-apples comparison between each filing, the Department reviewed the annual spending projections provided in each filing and compared projected spending between the overlapping 2023 through 2026 period as shown in Table 2.

[15] 2022 Compliance Filing, Attachment B at page 7.
[16] IDP Appendix D at page 17.

Table 2. Comparison of Xcel's Distribution Spending Projections for the 2023–2026 Period: 2021 IDP, 2022 Compliance Filing, and 2023 IDP

IDP Budget Category	2021 IDP (2023 - 2026) Spending (Millions)	Compliance Filing (2023 - 2026) Spending (Millions)	Compliance Filing (2023 - 2026) Δ	2023 IDP (2023 - 2026) Spending (Millions)	2023 IDP (2023 - 2026) Δ vs Compliance Filing
Age-Related Replacements and Asset Renewal	$ 715.70	$ 771.10	$ 55.40	$ 747.10	$ (24.00)
New Customer Projects and New Revenue	$ 160.90	$ 184.00	$ 23.10	$ 191.80	$ 7.80
System Expansion or Upgrades for Capacity	$ 202.20	$ 385.20	$ 183.00	$ 349.80	$ (35.40)
Projects related to Local (or other) Government-Requirements	$ 149.40	$ 139.80	$ (9.60)	$ 146.60	$ 6.80
System Expansion or Upgrades for Reliability and Power Quality	$ 158.10	$ 158.90	$ 0.80	$ 211.40	$ 52.50
Other	$ 189.10	$ 300.60	$ 111.50	$ 254.80	$ (45.80)
Metering	$ 10.70	$ 16.10	$ 5.40	$ 18.50	$ 2.40
Grid Modernization and Pilot Projects (including EV Programs)	$ 553.80	$ 670.10	$ 116.30	$ 361.90	$ (308.20)
Total Spending	**$ 2,139.90**	**$ 2,625.80**	**$ 485.90**	**$ 2,281.90**	**$ (343.90)**

Source: 2021 IDP at 18, 2022 Compliance Filing at 12, 2023 IDP at 21.

Table 2 calculates the difference in total spending and for each IDP Budget Category for the 2023 through 2026 period. Overall, Xcel's projected distribution system spending increased by nearly $500 million (23 percent) from the 2021 IDP to the 2022 Compliance Filing, but much of the increase was subsequently reversed in the 2023 IDP. This variation appears related to the changes to the spending forecast for EV Programs discussed above and identified in the "Grid Modernization and Pilot Projects (including EV Programs)" Budget Category.

Finally, the Department reviewed the 2023 IDP's actual distribution system spending from the 2018 to 2022 period and compared it to Xcel's projected distribution system spending from the 2023 to 2028 period (summarized in Table 3).

Table 3. Comparison of Distribution System Spending Reported in Xcel's 2023 IDP, Historical Actual (2018–2022) vs. Budgeted (2023–2028)

	Historical Actual (2018 - 2022)		Budgeted (2023 - 2028)		Δ	
IDP Budget Category	*Spending (Millions)*	*% of Total Spend*	*Spending (Millions)*	*% of Total Spend*	*(Millions)*	*%*
Age-Related Replacements and Asset Renewal	$ 491.00	34.16%	$ 1,272.20	30.09%	**$ 781.20**	**159.10%**
New Customer Projects and New Revenue	$ 177.60	12.36%	$ 296.40	7.01%	**$ 118.80**	**66.89%**
System Expansion or Upgrades for Capacity	$ 151.30	10.53%	$ 770.20	18.22%	**$ 618.90**	**409.05%**
Projects related to Local (or other) Government-Requirements	$ 169.00	11.76%	$ 231.50	5.48%	**$ 62.50**	**36.98%**
System Expansion or Upgrades for Reliability and Power Quality	$ 154.40	10.74%	$ 740.60	17.52%	**$ 586.20**	**379.66%**
Other	$ 196.20	13.65%	$ 374.60	8.86%	**$ 178.40**	**90.93%**
Metering	$ 33.40	2.32%	$ 27.60	0.65%	**$ (5.80)**	**-17.37%**
Grid Modernization and Pilot Projects (including EV Programs)	$ 64.40	4.48%	$ 514.90	12.18%	**$ 450.50**	**699.53%**
Total Spending	**$ 1,437.30**		**$ 4,228.00**		**$ 2,790.70**	**194.16%**

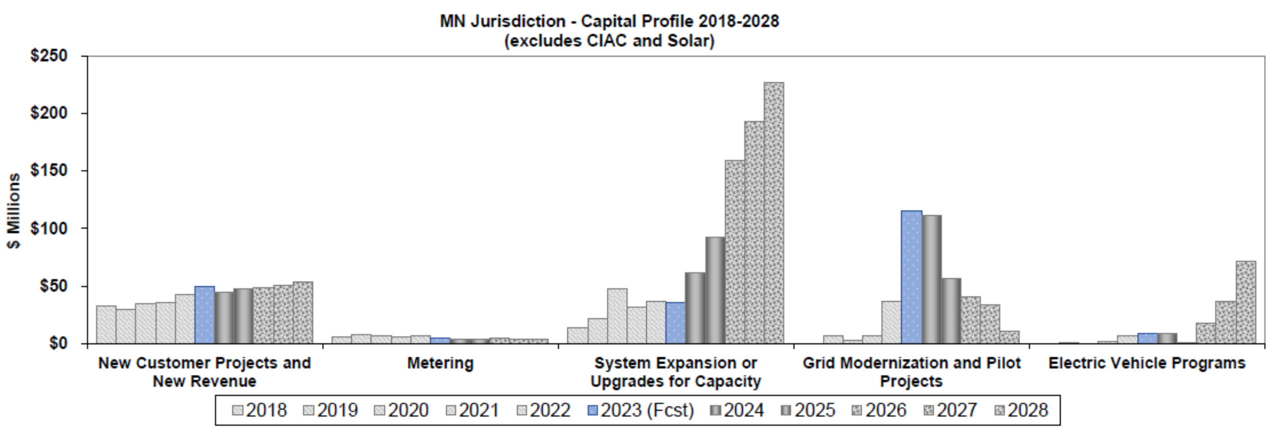
Source: IDP Appendix D at 16-17.

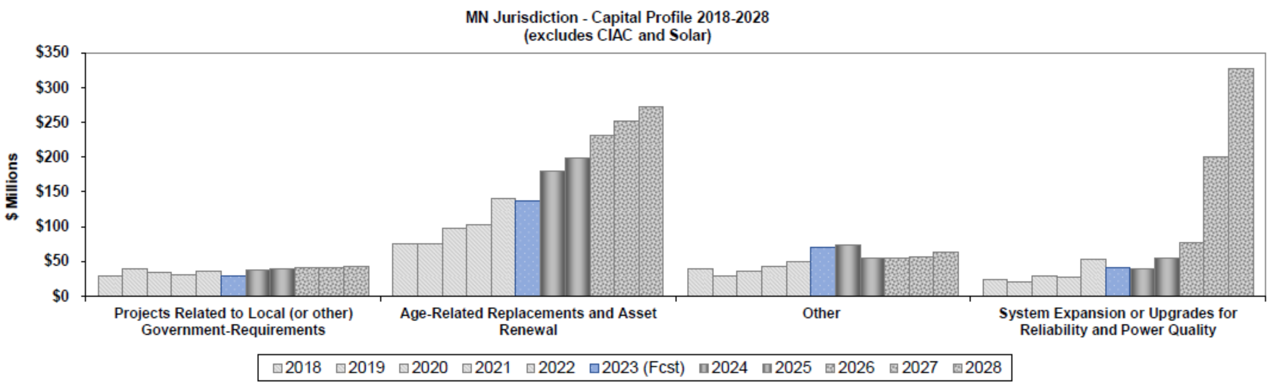
Xcel's total budgeted distribution system spending is projected to exceed $4.2 billion for the 2023 through 2028 period compared to the historical actual distribution system spending of $1.4 billion for the 2018 through 2022 period, a nearly 200 percent increase. Xcel has budgeted an increase in spending for every IDP budget category except for metering. The increase is distributed across multiple IDP budget categories but is largely attributable to the following categories: "Age-Related Replacement and Asset Renewal," "System Expansion or Upgrades for Capacity," "System Expansion or Upgrades for Reliability and Power Quality," and "Grid Modernization and Pilot Programs (including EV Programs)," each of which includes an increase of greater than $450 million. Together, these account for $2.437 billion (87 percent) of the $2.791 billion total increase in distribution system spending.

ii. Limitations of Budget Data

While the high-level budget summaries highlight the magnitude of total spending and increases in Xcel's distribution system budget, the IDP includes additional detail on overall budget trends. The capital profile trend for annual costs from 2018 through 2028 provided in Attachment I, along with a brief description of cost drivers, illustrates the gradual and, at times, dramatic increases across multiple IDP Budget Categories (see Figure 1).

Figure 1. Xcel Capital Profile Trend 2018–2028[17]





Xcel provides further detail for each IDP Budget Category in Attachment H, Capital Project List by IDP Category.[18] Within each IDP Budget Category, Xcel provides the annual budget for three general categories of activities: blanket, program, and project. Xcel explains that "blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects."[19] The blanket costs are identified in total for each IDP Budget Category. For the general category of programs, Xcel provides brief descriptions of the unique programs included in each IDP Budget Category in Appendix D, Section B.1.[20] For example, in the "Age-Related Replacements and Asset Renewal" IDP Budget Category, Xcel identifies specific programs included in this category: Pole Replacement Program, Reactive Line Programs, Substation Renewal Programs, and Line Renewal Programs.[21] Program costs in Attachment H, however, are identified in total across all the relevant programs for each IDP Budget Category, meaning that the costs associated with a specific program are not provided. Finally, the general category of projects within each IDP Budget Category identifies specific mitigation solutions

[17] IDP Attachment I at pages 1-2.
[18] IDP Attachment H
[19] IDP Attachment D at page 2.
[20] IDP Appendix D at pages 12-15.
[21] IDP Appendix D at page 12.

identified through Xcel's risk analysis and mitigation process.[22] For the projects identified, Xcel provides the annual budget for each unique project, providing the most granular data on the costs comprising the total IDP budget.

The list of capital projects in Attachment H, therefore, serves as the most detailed information in the IDP for stakeholders to understand what activities comprise Xcel's $4.2 billion in total distribution system spending. In some IDP Budget Categories, the list identifies a significant number of specific projects and, in total, the budgets for those projects comprise a large share of the total spending in that Budget Category. Specifically, the "Age-Related Replacements and Asset Renewal" and "System Expansion or Upgrades for Capacity" Budget Categories provide the most project-specific detail. However, even for these Budget Categories, the majority of the total spending falls under the general categories of "blanket" and "program," providing limited insight into the underlying costs and the increases included in the five-year budget.

For example, in the "Age-Related Replacements and Asset Renewal" Budget Category, the largest category of the distribution system budget, Xcel has included $1.1 billion in total spending from 2024 through 2028. Of this total, more than $800 million (71 percent) falls under the general category of "program," and annual costs double from $100 million in 2024 to nearly $200 million in 2028.[23] In addition, nearly $200 million (17 percent) in total spending through 2028 is identified as "blanket."[24] No further detail is provided regarding the costs associated with specific programs or the underlying assumptions that drive the increases. Department Table 4 below summarizes the budget for "Age-Related Replacements and Asset Renewal" from Xcel's Attachment H:

Table 4. IDP Budget Category "Age-Related Replacements and Asset Renewal" ($ in Millions)[25]

Age-Related Replacements and Asset Renewal	2024	2025	2026	2027	2028	Total
Blanket	$36.4	$37.5	$38.6	$39.8	$41.8	**$194.1**
Program	$100.4	$137.1	$170.7	$196.3	$199.8	**$804.3**
Projects	$42.6	$25.0	$21.9	$16.6	$30.8	**$136.9**
Total Budget	**$179.4**	**$199.6**	**$231.2**	**$252.7**	**$272.4**	**$1,135.3**

[22] Xcel discusses risk analysis as part of its System Planning process in Appendix A1, and it provides its risk scoring methodology and results in Attachment D.
[23] IDP Attachment H at page 1.
[24] *Ibid*.
[25] IDP Attachment H at page 1.

Similarly, the IDP Budget Category "System Expansion or Upgrades for Capacity" includes an extensive list of projects, but the majority of total costs within this Budget Category are included in the general categories "blanket" and "program." Most notably, the general category of "program" comprises $340 million (46 percent) of the total $734 million budget for 2024 through 2028.[26] This includes the $190 million placeholder for potential proactive system upgrades to increase DER hosting capacity[27] discussed elsewhere in these comments. The remainder, however, is not quantified or identified by program.

Xcel also does not differentiate costs by project in the IDP Budget Category "Grid Modernization and Pilot Projects" in Attachment H. Instead, the budget is separated into two items, "program" and "project." Xcel does provide project-specific data elsewhere in the IDP, but finding this data requires cross-referencing with a separate appendix in which Xcel includes project costs that are accounted for in areas other than the distribution budget.[28] To provide for more direct clarity from the total spending in the IDP Budget Category to the specific projects which comprise the category, Xcel could include the distribution portion of the grid modernization projects and identify the specific projects in Attachment H. This would improve the usefulness of Attachment H by providing stakeholders with a comprehensive list of the projects underlying Xcel's distribution budget, which would better address IDP Filing Requirement 3.A.29.

Lastly, the Department notes the limited visibility into the total budget for the Budget Category "System Expansion or Upgrades for Reliability and Power Quality." Xcel identifies the programs underlying this category in Appendix D: Cable Replacement, Feeder Performance Improvement Program, Reliability Monitoring System, and Viper Reclosers CSG.[29] In Attachment H, Xcel grouped all the costs into a single, annual amount, comprising the entirety of the nearly $700 million in the budget from 2024 through 2028.[30] The cable replacement budget, provided elsewhere in the IDP, comprises approximately $200 million (29 percent)[31] of the total Budget Category, but the remaining $500 million (71 percent) is left undifferentiated. Notably, the cable replacement budget is also not provided separately in Attachment H.

With the relative stability of the annual cable replacement budget, it is the remaining programs within the IDP Budget Category that drive the dramatic increases in the total budget. The Department provides Table 5 to help illuminate the budget trend within the IDP Budget Category "System Expansion or Upgrades for Reliability and Power Quality." As Table 5 illustrates, the budget for programs other than for cable replacement increases more than 80-fold from $3.5 million in 2024 to $282 million in 2028, and none of this increase is quantified in the budget information provided by Xcel.

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[26] IDP Attachment H at page 1.
[27] IDP Appendix D at page 13.
[28] IDP Appendix B1.
[29] IDP Appendix D at page 13.
[30] IDP Attachment H at page 3.
[31] IDP Appendix D at page 20.

Table 5. IDP Budget Category "System Expansion or Upgrades for Reliability and Power Quality" ($ in Millions)

System Expansion or Upgrades for Reliability and Power Quality	2024	2025	2026	2027	2028	Total
Cable Replacement	$35.2	$37.6	$40.5	$43.4	$45.6	**$202.3**
All Other Programs	$3.5	$17.8	$35.9	$157.8	$282.4	**$497.3**
Total Budget	**$38.7**	**$55.4**	**$76.4**	**$201.2**	**$328.0**	**$699.6**

Source: IDP Appendix D at 20, Attachment H at 3.

The Department notes the extensive information provided by Xcel throughout the IDP to explain its budgeting process and satisfy filing requirements. The Department's analysis illustrates areas where the information presented in the IDP limits the ability of stakeholders, including the Department, to fully understand the five-year budget. Department views this discussion as part of the ongoing, iterative process of IDP filings, particularly given the relatively nascent stage of the IDP process.

The Department is interested in exploring how the information presented in the IDP can be improved to enhance stakeholder understanding of Xcel's distribution system budget and welcomes feedback from Xcel and other parties.

Table 6 illustrates how various budget information is presented in the IDP, highlighting just some of the key sources the Department referenced to analyze Xcel's budget:

Table 6. Key IDP Budget-Related Sources

Budget-Related Appendix or Attachment	Title
Appendix A1	System Planning
Appendix B1	Grid Modernization
Appendix D	Distribution Financial Framework and Information
Attachment D	Distribution Risk Scoring Methodology
Attachment H	Capital Project List by IDP Category
Attachment I	Capital Profile Trend
Attachment J	O&M Profile Trend

As highlighted in the discussion above, the Department notes opportunities for Xcel to provide additional budget detail to inform what activities, projects, and programs are included in the budget and their associated costs, particularly as this helps to explain increases in the budget over the five-year timeframe. As previously noted, the general category "program" identified in Xcel's Attachment H could be enhanced by separating the total "program" budget into the specific programs, whenever possible, within the respective Budget Category. Similarly, the general category "projects" should be separated into known, project-specific budgets whenever feasible, such as in the "Grid Modernization and Pilot Projects" Budget Category discussed above. In tandem, these enhancements would allow Attachment H to serve as a single, comprehensive list of the elements that comprise Xcel's five-year budget.

The Department recommends Xcel be required to separate the total "program" and "project" budgets into discrete programs and projects for all Budget Categories in Attachment H, Capital Project List by IDP Category, to the fullest extent possible.

Additional opportunities to increase the understanding of the distribution system budget include providing the assumptions Xcel uses to develop the budget. This is particularly relevant for the general categories, "blanket" and "program," which are provided as a single line item in each Budget Category. In addition to separating the budget into discrete components, whenever possible, stakeholders stand to benefit from further explanation of the assumptions driving changes to the costs for each program included in the budget. For example, Xcel identifies the programs underlying the IDP Budget Category "System Expansion or Upgrades for Reliability and Power Quality,"[32] but it only provides a brief description of the cost drivers for the increases: "Includes continuing reliability programs focused on replacing infrastructure that is experiencing high failure rates, increase in outer years driven by potential resilience investments."[33] To arrive at the figures included in the budget as presented, Xcel presumably has made assumptions regarding such relevant factors as the failure rates of various assets, the number and proportion of assets it replaces each year, the costs for replacement parts over time, etc.

The Department does not presume to identify all assumptions that may be pertinent to a given program or the required level of specificity needed, as this specificity may vary by program and IDP Budget Category. However, the Department considers underlying assumptions as a useful addition to illuminate cost drivers in Xcel's budget and would seek further discussion from Xcel regarding what level of detail already exists through the budgeting process that could be included in its IDP filing.

The Departments requests Xcel provide a discussion in reply comments regarding underlying assumptions used to develop the budget.

As noted above, IDP Filing Requirement 3.A.29 requires Xcel to provide information on "[p]lanned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic[al] spending."[34] As the budget is currently presented in the IDP, the Department notes the limitations in understanding the changes to the historical spending levels on Xcel's distribution system. The magnitude of the total spending, as well as the dramatic increases compared to historical spending, suggests that additional detail and scrutiny is warranted.

[32] IDP Appendix D at page 13.
[33] IDP Attachment I at page 2.
[34] IDP Filing Requirement 3.A.29.

iii. Distribution Spending and Other Proceedings

In Notice Topic 18, the Commission requests input on the potential to align distribution spending with forthcoming rate cases. The Department views the discussion of Xcel's distribution budget, as well as the limited insight into components of the budget, as pertinent to the Commission's question regarding the alignment of distribution spending with forthcoming rate cases.

Order Point 29 of the Commission's July 17, 2023, rate case Order in Docket No. E002/GR-21-630 states:

> In its next Integrate[d] Distribution Plan (IDP), Xcel must propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to:
>
> a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget;
>
> b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.[35]

In response to Order Point 29.b, Xcel notes "there are no decisions being requested of the Commission at this time,"[36] and, elsewhere, that it is "not proposing certification of any grid modernization investments with this IDP,"[37] which differs from prior IDPs in which specific project certifications were requested.

Xcel also notes the inherent mismatch between the IDP and rate cases in terms of scope, purpose, timing, and the financial information included in the respective filings.[38] As one key illustration of this mismatch, Xcel notes "that cost recovery proceedings present capital additions and revenue requirements, whereas the IDP reports capital expenditures. Perfect alignment between filings will not be possible; cost recovery filings represent the most accurate and relevant cost information."[39]

However, stakeholders have expressed interest in making comparisons between budgets presented in IDP filings and other dockets, including cost recovery proceedings, and the current challenges of doing so.[40] The Department shares this interest. While it is true that elements of the IDP budget are

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[35] *Findings of Fact, Conclusions, and Order, In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota, Docket No. E002/M-21-630* (July 17, 2023). *Hereinafter*, July 17, 2023, Order.
[36] IDP at page 25.
[37] IDP Appendix C at page 5.
[38] IDP at pages 25-27.
[39] IDP at page 27.
[40] *Ibid.*

mismatched with cost recovery proceedings, it is also true that a portion of the activities that comprise the IDP budget will ultimately be presented for cost recovery in future proceedings. The regulatory process is improved by use of consistent information across processes.

One approach to aligning the financial information in the IDP with future cost recovery would be to provide additional detail on the underlying components of the IDP budget. Xcel also proposes modifying IDP Filing Requirements related to budget categories to facilitate the comparison of financial information across various proceedings, including those for cost recovery. The Commission requests input on Xcel's proposal in Notice Topic 21, for revising the IDP Filing Requirements by removing the requirement that financial information be reported in IDP-specific categories.

Currently, the IDP Filing Requirements for financial information requires reporting categories that are unique to the IDP process and differ from Xcel's internal budget categories. The current IDP Filing Requirements utilize the following categories:

a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government requirements
g. Metering
h. Other
i. Electric Vehicle Programs[41]

Xcel provides multiple justifications for the removal of the IDP-specific budget categories. First, Xcel notes the manual work required to translate its capital budget from its internal categories into the IDP-specific categories, particularly complicated by the lack of direct correspondence between the two categorization systems.[42] Table 7 illustrates the relationship between the two systems.

Table 7. Xcel Table D-1: Financial Categories Cross-Reference

IDP Category	**Xcel Energy Capital Budget Category/Categories** (if more than one, categories are separated by a semicolon)

[41] IDP Filing Requirements 3.A.26, 3.A.29.
[42] IDP Appendix D at page 2.

Age-Related Replacements and Asset Renewal	Asset Health & Reliability
New Customer Projects and New Revenue	New Business; Capacity
System Expansion or Upgrades for Capacity	Capacity
Projects related to Local (or other) Government Requirements	Mandates
System Expansion or Upgrades for Reliability and Power Quality	Asset Health & Reliability
Other	Fleet, Tools & Comm
Metering	New Business
Non-Investment	Capacity; Fleet, Tools & Comm; New Business
Electric Vehicle Programs	Electric Vehicles

Source: IDP Appendix D, Table D-1 at page 2.

Second, Xcel notes that the O&M budget does not lend itself to a manual process akin to the capital budget to comply with the IDP-specific categories and presents the O&M budget in a functional view in the IDP that differs from the requirements.[43] Third, Xcel proposes the IDP Filing Requirement revision to streamline comparisons across dockets and cost recovery proceedings.

The Department generally agrees that Xcel's proposed modifications to the IDP Filing Requirements to remove the IDP-specific categories for financial information are beneficial and provide consistency of budget categories across Xcel dockets. This proposal would also align with the Commission's directive in its July 17, 2023, Order. The Department supports the improved alignment of the IDP process with other dockets, including cost recovery proceedings. Furthermore, to facilitate a comparison of IDP filing requirements and budgets across all IDP filings, the Commission should implement these (or similar) revisions in upcoming procedures with other utilities.

Notably, the other utilities filing IDPs in 2023 did not request modification of the IDP-specific budget categories.

The Department does not believe this would be a burdensome request, as it understands that Xcel's budget process begins with the creation of its budget using its internal budget categories prior to

[43] IDP Appendix D at pages 23-25.

conducting the manual process to convert the budget to the IDP-specific categories and, therefore, this data is readily available to Xcel.

While the IDP may not be the ideal forum to address the prudency of the projected spending levels, it is important for the information presented to allow the Commission and stakeholders to understand distribution system planning and spending. Because potential IDP spending intersects with cost recovery mechanisms, the IDP has become the *de facto* forum for this discussion as identified in the fourth planning objective: "Ensure[ing] optimized utilization of electricity grid assets and resources to minimize total system costs."[44] With adjustments to the budget information presented in this IDP and alignment of budget categories with other proceedings, the IDP process can better meet this objective.

C. BUDGETS AND COST ALLOCATION FOR DISTRIBUTION SYSTEM UPGRADES TO ACCOMMODATE DISTRIBUTED ENERGY RESOURCES (DER)

Notice Topic 17: What guidance should the Commission give on budgets and cost allocation for distribution system upgrades to accommodate DERs, 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

f. Proactive grid upgrades in anticipation of future DER growth

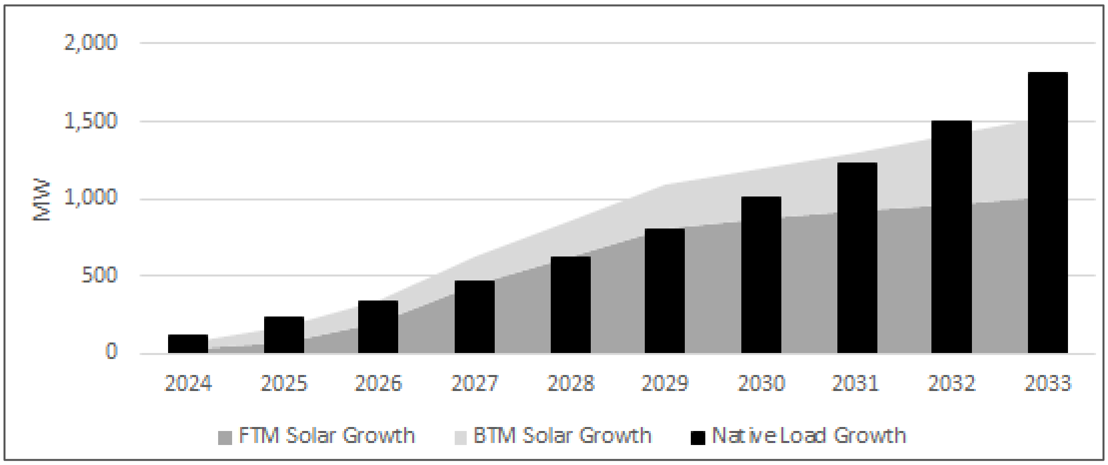
Allocating capacity expansion budgets that result from any single DER at a system-wide level can be a difficult task to accomplish due to the interrelatedness of these measures. For example, an electric panel and/or transformer upgrade made at a home or business to install electric vehicle charging may then be used to install heat pumps for space and water heating, and the upgrade would also increase the capacity to host additional behind-the-meter (BTM) solar PV. When a homeowner or business is considering the large upfront cost of a capacity upgrade, they will typically plan to host all new anticipated loads to avoid making additional capacity upgrades in the future. With Xcel forecasting a threefold load growth in the next 30 years, it is essential that Xcel proactively plan to meet its forecasted load for capital assets with lifespans beyond a 30-year horizon. For example, overbuilding too quickly will put upward pressure on rates if infrastructure is built too soon to accommodate DERs that never reach the adoption rates planned for in the Xcel's load forecast.

The balance between proactively planning for load growth and keeping rates low is a difficult process to navigate. This challenge is perhaps best illustrated by the push and pull of meeting the State's goals for solar adoption. There are 261 projects on hold at capacity-constrained feeders, and 138 new projects that have applied to build solar projects on capacity-constrained feeders in the space of about

[44] IDP Planning Objective 4.

one-and-a-half years.[45] Traditionally, costs have been passed on to solar developers. Xcel discussed alternative cost allocation systems in Appendix I which could alleviate some of this stress. However, looking at the broader context of the distribution system reveals that the forecasted load growth is anticipated to surpass solar DER growth by 2032, as shown in Figure 2. In complex situations such as this, it is clear that solar developers will be subsidizing some added capacity benefits that will benefit ratepayers in the near term, raising cost allocation questions.

Figure 2. Cumulative Xcel Native Peak Load Growth vs Solar DER Growth for IDP Med Scenario



Source: Derived from data provided in Appendix M.

Xcel forecasts an increase in native peak load of 1,811 MW by 2033[46] in its IDP Med Scenario, of which 716 MW (39.5 percent) will come from beneficial electrification, and 546 MW (30.1 percent) will come from electric vehicles. DERs are anticipated to contribute nearly 70 percent of the anticipated peak load growth. The "System Expansion or Upgrades for Capacity" budget category largely falls in this territory, with a five-year estimated budget of $770 million (18.2 percent). However, the "Age-Related Replacements and Asset Renewal" budget category is projected to spend $1,272 million ($30.1 percent) on replacing infrastructure. This is arguably the best time to also make capacity upgrades. Xcel has not sufficiently explained if the "Age-Related Replacements and Asset Renewal" budget also includes planned or proactive capacity expansion benefits.

The Department requests that Xcel provide further information in reply comments as to whether the "Age-Related Replacements and Asset Renewal" budget also includes capacity expansion benefits.

If the Commission's goal is to incentivize increased utilization of distribution lines while maintaining or enhancing reliability, then avoiding capacity upgrades has the effect of building less infrastructure, which keeps rates low. It may not always be possible to avoid capacity upgrades, especially in the context of 300 percent forecasted load growth. Traditionally, Xcel has participated in the ECO/CIP

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[45] IDP Appendix E at page 48.
[46] Base year of 2023.

program to enhance energy efficiency and enrolled customers in its demand management (DM) programs to control load growth, both of which have been cost-effective programs. Here, Xcel presents multiple, newer solutions to avoid capacity upgrades, such as NWA, enhanced enrollment in DM programs with Distributed Intelligence (DI), managed EV charging, and V2G. The current influence of these programs, with the exception of managed EV charging, has thus far been minimal to non-existent[47] The progress thus far on the deployment of new solutions to reduce demand results in increased pressure on the distribution system to expand its capacity, which will drive up rates. Finally, Xcel did not provide a discussion on the potential impact of alternative tariff structures that could further incentivize customers to shift load away from peak times, but Appendix J does provide a discussion of possible Distributed Intelligence (DI) solutions to adapt to existing tariffs.

The Department welcomes feedback from Xcel and other parties in reply comments as to whether discussion of alternative tariff structures belongs in an IDP.

When capacity upgrades are unavoidable, Xcel has a process to identify solutions and identify the least cost mitigation strategy. Xcel discusses how it identifies capacity constrained feeders in Appendix A1. Potential solutions include reinforcing existing feeders, adding or extending feeders, upgrading substations, or building entirely new substations. Xcel also has an established process to conduct NWA, but the scope of applicable projects has thus far been very limited. Potential solutions to expand eligibility for NWA solutions are discussed in Section 0 (Notice Topic 16.A).

The sum of all considerations discussed in this section yields the “System Expansion or Upgrades for Capacity” budget estimate. As discussed in Notice Topic 16.C, the budget discussion presented throughout the IDP does not go into sufficient detail for the Department to comment on the drivers of cost increases. The list of capital projects presented in Attachment H provides a list of each project, its estimated five-year budget, and its Risk Score, which is stated by Xcel to be a form of cost-benefit analysis. However, this list does not present enough information to evaluate other quantitative metrics to evaluate the cost-effectiveness of the proposed upgrades. The metric of increased feeder capacity is of particular interest in the context of Notice Topic 17. Further, reliability upgrades and associated metrics to accommodate DERs are also relevant for this section.

The Department welcomes feedback from Xcel and other parties as to the feasibility of providing additional metrics to evaluate cost-effectiveness of capacity projects and which metrics would potentially be the most useful for evaluation.

Having now established the drivers of distribution system upgrade costs and the interrelation between DERs, the Department can provide specific feedback to address the Commission’s recommended Notice Topics.

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[47] Xcel proposed three potential NWA projects in Appendix F. These projects will be re-evaluated in 2024 and would not be in service until 2028 (IDP Appendix F, P 41). In the Xcel 2021 IDP filing (E002-M-21-694), Xcel withdrew its request for certification for its DI program and clarified in its IR responses that it is not currently seeking approval for DI-related expenses. Xcel proposes its first V2G demonstration with a pilot of two school buses (IDP Appendix H9).

1. *Solar Sited with Customer Load and Solar Sited in Front of the Meter (Notice Topics 17.A,B)*

   i. *Estimated Upgrade Costs*

Xcel often combines the presentation of costs for BTM and front-of-the-meter (FTM) solar, which makes it difficult to assess them separately. Budgeting and cost allocation for DER solar is discussed in Appendix E and I. Xcel does not provide site-specific cost estimates, and instead relies on a flat marginal cost estimate of $320/kW, which has been used in other dockets. This cost is applied only to solar arrays installed that violate the planning limit at each feeder for each applicable year. In the five-year IDP budget timeframe, Xcel forecasts the addition of 304 MW of BTM solar and 789 MW of FTM solar, based on the IDP High Scenario that assumes the full FTM quotas will be reached each year in addition to a 25 percent increase over Xcel's rooftop medium adoption forecast. Estimated upgrade costs are not broken down by BTM/FTM, and the allocation model used is feeder-specific; so, it is not possible to estimate costs solely based on the ratio of installed capacity for BTM/FTM installations.

Xcel presents the estimated cost for combined BTM/FTM solar in Table I-1, reproduced here as Table 8. Xcel proposes two planning limits for its budget estimate. The first is the current Technical Planning Standard (TPS), which allows for 80 percent of the continuous rating plus the daytime minimum load. The 50 percent standard limits FTM solar interconnections up to 50 percent of the continuous rating and limits FTM plus BTM solar to no more than 100 percent of the continuous rating. Xcel claims a cost increase of $147.8 million with the 50 percent standard compared to the TPS. Applying the 50 percent standard has the effect of raising the upfront cost for FTM arrays and increasing capacity for BTM arrays that would be realized in the future. Xcel does not anticipate a cost savings from the 50 percent standard until the mid-2040s. Therefore for practical purposes, the 50 percent standard would disincentivize the development of FTM solar in favor of BTM solar. It is possible that FTM solar installations could use up the entire hosting capacity for certain feeders, which could make additional capacity upgrades for BTM solar financially impractical. If the 50 percent standard is adopted, it would likely slow the adoption rate of FTM solar and thus would lead to less solar installed overall. The capacity reservation or new TPS is at issue in Docket No. E999/CI-16-521, in which the Department has submitted comments.

Table 8. Xcel Table I – 1: Summary of Upgrade Cost Components for Each Planning Limit Scenario

Planning Limit Scenario	Existing Constraint Cost	2023-2052 Forecast Cost	Total 30-year Cost
TPS	$47.7M	$992.2M	$1,039.9M
50%	$154.8M	$1,032.9M	$1,187.7M

Source: IDP Appendix I.

Xcel provides two forecasts for its scenario planning. The first forecast is referred to by Xcel as its "Corporate-Level" forecasts, which are used by Xcel to forecast load growth in Low, Medium, and High sensitivities. In the second forecast, Xcel has an additional filing requirements C1 & C2[48] (10 percent and 25 percent, where applicable) of DER deployment than its Corporate-Level forecasts, which are referred to by Xcel as IDP Low, Medium, and High Scenarios.

While Xcel forecasts upgrade costs of over $1 billion in the next 30 years for its IDP High Scenario, it is worth noting that Xcel's expected solar adoption rates are lower than in the IDP High Scenario, which assumes the Xcel Corporate-Level solar FTM forecast reaching the full legislative quotas[49] and the BTM Corporate-Level medium forecast plus 25 percent. The Xcel IDP High Scenario, presented in Appendix I, forecasts the addition of 622 MW of BTM solar and 1,254 MW of FTM solar by 2033. The Xcel Corporate-Level Medium adoption solar forecast anticipates the addition of 498 MW (80.1 percent) of BTM solar and 1,047 MW (83.5 percent) of FTM solar by 2033.

ii. Capacity Cost Reduction Measures

Xcel presents several methods to reduce the need for capacity upgrade costs for solar. Smart inverters are discussed in their capacity to regulate volt-var and volt-watt outputs. Xcel concludes that the benefits of volt-var have largely already been realized but notes a potential for volt-watt controls. This could temporarily lower the power output at the inverter level, which is a form of curtailment, and would only be used in emergency situations. This solution is therefore unlikely to significantly lower upgrade costs. Grid modernization efforts, which include the Advanced Distribution Management System (ADMS) and the DER Management System (DERMS) both offer the ability to monitor DER solar performance and allow for Xcel to control DERs. The benefits of these systems to avoid capacity upgrades has not been clearly articulated, however they appear to support the utilization of new export tariffs. Under new export tariffs, Xcel would allow a solar array to be installed that can either be curtailed by Xcel when needed or would allow a customer to install a solar array with a battery that never exports to the distribution grid, in exchange for lowered interconnection costs. It is unclear how significantly curtailment could impact the finances of individual solar owners, but this option may serve as a temporary stopgap measure until either further capacity upgrades are needed to absorb new load or more solar arrays are requesting interconnection to a saturated feeder, which could further subsidize a group cost-sharing for a capacity upgrade.

iii. Xcel Cost Allocation Scenarios

The most significant challenge posed to a distribution grid facing ever increasing levels of DER solar interconnections is reaching the saturation limit for a feeder or substation. Any single project that runs into a capacity constraint at the feeder or substation level could run into significant capacity upgrade costs that would prevent the project from getting built. This creates the need to attempt to pool costs

[49] IDP Appendix A1 at page 37. Quotas established in Minn Stat. Of 100 MW / yr in 2024 - 2026, 80 MW / yr in 2027 – 2030, and 60 MW / yr each year thereafter.

between multiple prospective projects to lessen the impact upon all projects. Xcel presents several potential allocation scenarios to pool upgrade costs in Appendix I.

The first option presented in Appendix I, "Retroactive Cost Sharing Between DG Facilities"[50] would impose the entire upgrade cost on the first applicant to trigger an upgrade. If additional facilities interconnected thereafter, the first applicant and each additional applicant would then receive true-up payments for subsequently interconnected facilities. This option was suggested by a stakeholder at the June 12, 2023, IDP stakeholder meeting.[51] This process would impose substantial risk for the first facility, with no guarantee of payment from subsequent facilities if they are never built. Xcel states that this process would also be administratively burdensome.

The second option presented in Appendix I is "Cost Sharing 2.0."[52] In this approach, the capacity upgrade costs would be allocated on a per-kW basis for each interconnecting facility. The need for upgrades would be assessed based on either the interconnection queue or the need for additional capacity upgrades. Xcel states that this option would also be administratively burdensome. Xcel notes that the Commission has previously approved an applicant-wide fee for facilities up to 40 kW that can pay for upgrades up to $15,000.

The third option presented in Appendix I, "Costs of Interconnection Paid by the Utility and Recovered from All Customers,"[53] would rate-base upgrade costs to all customers. Xcel notes that there are societal benefits for all ratepayers when DER solar is installed. Xcel notes that it has already received a $10 million budget allocation from the Distributed Energy Resources System Upgrade Plan approved by the Minnesota Legislature in 2023.[54] Further, Xcel has added a preliminary $190 million placeholder to proactively make upgrades to host increased DER solar, which is discussed further in Notice Topic 17.F.

The final option presented in Appendix I is called the "Network Upgrade/System Enhancement Credit."[55] In this option, upgrade costs would be shared between the solar projects and all ratepayers. This hybrid approach would allocate capacity upgrade benefits between the solar projects and the rate base, when it can be demonstrated that there is a mutual benefit. Xcel notes that this process would be lengthy to develop and would require significant stakeholder involvement to agree upon common values of upgrades and corresponding allocations to solar projects and to all ratepayers.

iv. Department Feedback on Xcel Cost Allocation Scenarios

In the second option, "Cost Sharing 2.0," Xcel presents a scenario where upgrade costs are shared on a per-kW basis among a pool of applicants. It is not stated if this proposal would include small facilities

[50] IDP Appendix I at page 12.
[51] IDP Appendix I at page 12.
[52] IDP Appendix I at pages 12-13.
[53] IDP Appendix I at page 13.
[54] Minn. Stat. § 216C.378 as added by Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F No. 2310), Article 12, Section 38.
[55] IDP Appendix I at pages 13-14.

40 kW and under, but in theory the cost allocation could include or exclude this group. In the "Cost Sharing 2.0" discussion, Xcel notes that the Commission has approved a $15,000 credit for capacity upgrades for projects up to 40 kW, which is funded by a flat fee for interconnection applications. A similar proposal for cost-sharing among all larger facilities, rather than only at a group of facilities at one feeder or substation, was not presented but is of interest to the Department. Pooling costs amongst all applicants could reduce or eliminate prohibitive cost barriers for facilities seeking to interconnect on saturated feeders. Further, it is not clear what would happen if a residential facility were to apply to interconnect on a feeder whose upgrade cost may be in the hundreds of thousands of dollars. In this case, the $15,000 credit would not be sufficient to interconnect the new facility. Under "Cost-Sharing 2.0," a residential facility may either contribute up to the $15,000 cap, contribute its full share of costs by kW (if higher), or be excluded from the upgrade process entirely.

The Department recommends Xcel provide options, if any, to help distribute costs to interconnect a small residential facility on a saturated feeder including whether a flat interconnection fee, similar to the small solar array fee, has been considered for larger facilities.

The Department supports any cost allocation proposal that has the effect of increasing solar DER installation while keeping costs low for ratepayers. Adopting a rate-based solution for all solar DER capacity upgrades would require significant justification as to the benefits received by all ratepayers, and thus far, no such justification has been made. However, consistent *Figure 2. Cumulative Xcel Native Peak Load Growth vs Solar DER Growth for IDP Med Scenario*, there is a relationship between forecasted load growth and forecasted solar DER growth that warrants further consideration. The cost allocation structure used in NWA analysis provides a potential framework to consider the mutually beneficial value of solar DER capacity upgrades and capacity upgrades needed for load growth.

The Department welcomes feedback from Xcel and other parties on the feasibility of implementing a cost allocation system for capacity upgrades.

2. Energy Storage Devices (Notice Topic 17.C)

Energy storage does not feature prominently in Xcel's IDP. Xcel reports that there are 493 BTM projects currently connected to the distribution system, with a combined capacity of 2.1 MW.[56] There are an additional 48 projects in queue, with a combined capacity of <1 MW. The Xcel Corporate-Level Medium Scenario calls for 30.5 MW of new storage to be installed between 2023 and 2033. The amount of storage forecasted by Xcel over the next 10 years is equivalent to 0.3 percent of the 2033 forecasted peak load. The impact on the distribution system capacity upgrades budget within the current forecast is negligible.

Xcel discusses several battery pilot programs in Appendix B3. The Renewable Battery Connect program in Colorado offers incentives to customers who charge their batteries with 100 percent renewable energy and allow Xcel to discharge the batteries when needed. The program acts as a VPP, which allows Xcel to dispatch power from batteries in a similar manner to how a power plant operates. Such

[56] IDP Appendix AI – Table A1 – 6: Storage Systems - NSPM State of Minnesota

a system would act as a precursor to partially enable FERC Order 2222, which will require utilities to allow for greater DER participation on wholesale power markets. Xcel briefly discusses its Resilient Minneapolis Program and Community Resilience Initiative in Colorado, both of which seek to install microgrids with battery systems at locations of community importance. If projects similar to these are deployed at a much larger scale, the infrastructure could have an impact on grid capacity, but these projects are all too small to affect distribution capacity budgets.

Finally, Xcel provides a discussion of its NWA process. Three projects were identified for potential deployment by 2028, pending review next year. Xcel identified 16 potential projects for NWA analysis over $2 million, and it found three potential projects that could be eligible for an NWA solution. Of the three potentially net cost-beneficial NWA solutions identified, Xcel proposed battery solutions for only two cases, with battery capacities of 0.17 MW / 0.29 MWh and 1.13 MW / 2.45 MWh in the first and third cases, respectively. In contrast, these two solutions proposed solar systems of 8.6 MW for both, which greatly overshadow storage,[57] a preference which partially explains this result.

The Department does not expect BTM batteries to play a significant role in the avoidance of capacity upgrades within the five-year IDP budget period. The application of NWA provides a more significant opportunity for the avoidance of capacity upgrades. The Department has provided a number of solutions to improve upon the NWA process, which are discussed in Section 0 (Notice Topic 16.A).

The Department also notes the potential for battery storage to act as an NWA-type solution for feeders that have reached maximum solar DER hosting capacity. While other solutions, such as flexible interconnection or traditional capacity upgrades, may be more cost-effective, the strategic deployment of batteries at the feeder or substation level would allow for significantly higher levels of solar DER penetration without having to invest in other capacity upgrades. Battery solutions can be designed to have modular upgrade capacity, which may lower the marginal cost for new solar facilities to interconnect. Such upgrades could also potentially provide grid resilience and power quality benefits in addition to the NWA benefits presently analyzed by Xcel.

The Department requests a discussion from Xcel in reply comments as to whether energy storage has been considered by Xcel to alleviate current or future solar DER capacity-constrained feeders, and whether this subject warrants further investigation.

3. Electric Vehicles (Notice Topic 17.D)

The TEP process has been discussed at length in a previous proceeding that addresses IDP Notice Topics 1-13. In particular, the question of allocation of costs at the home or business was addressed in responses to these Notice Topics and will not be discussed here.

Xcel requests a budget allocation of $17.3 million to meet the needs of its existing EV pilots for its fleet and public charging programs until the end of 2025, which is only anticipated to meet the existing needs. In Attachment H, Xcel estimates its 2023–2028 budget for all Electric Vehicle Programs at

[57] IDP Appendix F at page 25.

$137.4 million. Appendix H12 offers a better look into upgrade costs specific to the distribution system. Between 2024–2027, Xcel estimates that "Transmission and Distribution Capacity" costs for the Minnesota Test across the TEP will cost $7.57 million, however this budget category is combined with transmission and distribution, so it is difficult to understand the specific amount dedicated to distribution alone. Further, the cost-benefit analysis did not include 2028; but with this year added, upgrade costs would still be under $10 million and thus would compose a relatively small share of the entire EV program budget over the next 5 years.

Xcel notes in Appendix H that it may be difficult to keep up with demand to interconnect EVs. This problem is anticipated mostly to occur in the fleet and public charging sectors, which Xcel notes can have interconnections exceeding 1 MW. In these instances, customers may have to wait for distribution system upgrades to accommodate the large additions of load, and depending on the magnitude of the upgrade needed, it could take between 1 to 10 years to make the upgrade.[58] Anticipating where capacity upgrades are needed to allow for a timely deployment of EVs is a significant challenge for Xcel. The utility can either wait for applications to come in to justify a capacity upgrade, as it does with solar, or risk making proactive capacity upgrades that may not get used for years, if ever. The results on either side could be either delayed deployment or EVs or misallocated costs, both of which are undesirable outcomes for the public.

While capacity upgrade costs are currently relatively modest in comparison with the $4.2 million distribution budget proposed by Xcel, these costs will continue to accrue at an increasing rate, which is reflected in the cost-benefit analysis presented in Appendix H12. The EV adoption forecasts presented in Appendix A1 illustrate that Xcel is anticipating a significant increase in EV adoption, and while the costs remain modest in this IDP, it should not be expected that costs remain modest. In order to keep costs low, it is essential that Xcel maximize distribution line utilization to avoid capacity upgrades whenever possible. EVs have the benefit of being able to charge at different times of the day, when energy costs are lowest; this is not the case for all sources of load, including space and water heating, which are discussed in Notice Topic 17.E. However, fleet and public charging will not be as malleable as charging at homes, and thus increased utilization for these purposes will put further upward pressure on distribution capacity upgrade costs.

Finally, Xcel attaches a whitepaper from Guidehouse on the potential for V2G in Appendix H3. V2G allows for the possibility of EVs to discharge onto the grid when the grid is at a point of high stress. V2G programs have been discussed for years, but they have not reached the mainstream. Significant challenges are posed in the installation of 2-way charging capabilities, in addition to concerns about battery degradation and reserve capacity. Should V2G programs demonstrate successes in the future, these technologies hold the promise to provide further grid flexibility, which can lower the need for capacity upgrade costs. Xcel proposes in its School Bus V2G demonstration program to test the concept on two buses. The novelty of V2G and its pace of adoption mean that V2G will not be a significant

[58] IDP Appendix H at page 20.

influence in near-term distribution system planning; however, this technology holds the potential for EVs to be grid assets that could potentially lower costs for the public.

4. Space Heating, Water Heating, and Other Electrification Use Case – Notice Topic 17.E

Xcel provides almost no discussion about beneficial electrification, including space heating, water heating, and other use cases. Appendix A1 provides a beneficial electrification forecast but provides little explanation beyond the presentation of the forecast itself. The lack of information about beneficial electrification is contrasted by the projection of 716 MW (39.5 percent) of new load growth from beneficial electrification between 2024–2033. Further, Xcel notes that beneficial electrification from commercial and industrial sources has not been included in its forecast. This represents a significant omission in the beneficial electrification forecast, as the residential sector composes only 23 percent of electricity sales.[59] While beneficial electrification takes place outside of current electricity sales, the scale of current electricity use is illustrative of the gap in Xcel's forecast. It should be noted that electrification of particularly industrial sources is an area of continuous innovation, with few, if any, active demonstration projects to test electrified industrial-scale processes. This makes it difficult to forecast load growth for industries that are still being developed. Further, the economics of electrified industrial activity are challenging due to the low cost of natural gas.[60] Given this context, it is understandable why these sources have been omitted in this iteration of Xcel's forecast, however the importance of capturing activities in these sectors remains high and should be a focus for Xcel's next IDP.

Xcel does not provide any discussion about how an additional 716 MW of beneficial electrification by 2033 is expected to affect distribution capacity upgrades. In the short term, the effects of beneficial electrification may increase utilization of existing distribution lines, as traditionally peak loads are experienced in the summer. However, as beneficial electrification increases, there will be increasing pressure on the distribution grid to supply more energy in the winter.[61] Xcel is certainly aware of this issue but provides little discussion of the topic beyond a brief reference to winter peaking in Appendix F – NWA. When combined with EVs, and particularly in the context of their reduced winter performance, the winter peak problem will be exacerbated with increased levels of EVs and beneficial electrification. As the coldest part of the day is typically at night, requiring the highest heating loads, managed EV charging may have to shift to daytime to avoid additional capacity upgrades. While none of these issues are challenging the grid today, it is important that Xcel be aware of these problems and start planning for them now, which is why the IDP process exists.

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[59] IDP at page 12.
[60] Great Plains Institute and the Center for Energy and Environment. *Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations*. (July, 2021).
[61] Great Plains Institute and the Center for Energy and Environment. *Decarbonizing Minnesota's Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations.* (July, 2021).

Beneficial electrification is being incentivized by the passage of the *Natural Gas Innovation Act*,[62] the *IRA*, and additional state incentive programs, all of which help natural gas utilities decarbonize, partly through beneficial electrification. Xcel has an open docket[63] to discuss the *Natural Gas Innovation Act* and is currently working on the topic.

The TEP has an entire appendix devoted to this discussion, yet Xcel is only forecasting 546 MW of load growth from EVs compared to 716 MW forecasted for beneficial electrification from 2024 to 3033. The omission of any substantive discussion on the impacts of beneficial electrification on the distribution grid leaves an important gap in the IDP process. Beneficial electrification has the potential to fundamentally reshape how utilities think about peak loads and distribution capacity planning.

Given this context, the Department recommends that the Commission adopt a new filing requirement to specifically address how beneficial electrification is anticipated to affect the distribution grid.

5. Proactive Grid Upgrades in Anticipation of Future DER Growth (Notice Topic 17.F)

Xcel has included $190 million in the five-year budget for proactive system upgrades to increase DER hosting capacity.[64] It indicates that it has included this funding in response to stakeholders' feedback that increased hosting capacity is a growing priority for the state.[65] Xcel describes this funding as a placeholder estimate, with no identified specific uses for the funding, and that it is interested in feedback on the inclusion of this amount in the budget and how it should be prioritized.[66]

The Department appreciates Xcel's desire to be responsive to the priorities of stakeholders, including enabling additional DER on its system. As Xcel notes, 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.[67] This is the first time Xcel has included such proactive funding in its budget, so the Department is appreciative of Xcel's interest in feedback on this new approach. [68]

In its IDP, Xcel provided limited information to facilitate evaluation of the proposed funding. Xcel referred to the placeholder estimate for hosting capacity upgrades only in terms of the entirety of the $190 million funding in the years 2025 through 2028. In response to a Department informational request, Xcel clarified that the $190 million budget includes $10 million in the first year, 2025, and an

[62] Minn. Stat. § 216B.2427.
[63] Northern States Power Company d/b/a Xcel Energy. *Petition: Natural Gas Innovation Act Plan, Docket No. 23-518*, (December 15, 2023).
[64] IDP at page 21.
[65] *Ibid.*
[66] IDP Appendix A1 at page 25.
[67] IDP Appendix A1 at page 25.
[68] *Ibid.*

additional $60 million for each subsequent year, 2026 through 2028.[69] In explanation of its methodology to develop a proposal in the amount of $190 million, Xcel provided the following response:

> $190 million was intended to be a high-level indication of how much system upgrades could cost and was included based on feedback from stakeholders about what investments they would like to see in our distribution system in relation to hosting capacity. We started with an assumption of $10 million for the first year, as it would take time to identify and initiate projects. For each year after, we allocated an additional $60 million as an indication of the funding that may be necessary. The $190 million was not meant to represent the total of how much funding would be required to implement system upgrades, but simply a starting point to be balanced with affordability and public policy considerations. As discussed in Appendix I: Distribution System Upgrades of the IDP, we indicated that the total 30-year cost of distribution upgrades to accommodate the forecasted solar adoption could exceed $1 billion.[70]

While Xcel is upfront about referring to the funding as a placeholder estimate for proactive upgrades, the Department is, nonetheless, concerned with the level of analysis upon which Xcel relied to generate the amount included in the proposed funding.

To facilitate evaluation of the appropriateness of the proposed funding, the Commission should direct Xcel to indicate how many projects the funding for hosting capacity upgrades would support, what level of additional DER those projects could enable, and how much of the forecasted DER increases this funding could address.

Notably, the comparison Xcel provides in its response above to the 30-year cost of distribution upgrades of $1 billion identified in Appendix I is based on the forecasted solar adoption in the “IDP High” DER scenario.[71] However, Xcel’s budget is not developed using this scenario, so the comparison provides limited value. Xcel’s budget plan, understandably, is based on “known and expected” load growth and known trends and is, therefore, not speculative.[72] The proposed hosting capacity upgrades, then, are an exception to the rest of Xcel’s budget:

> This “Budget Plan” scenario is a forecast of traditional load growth on the distribution system and does not include the impact of the scenario forecasted DER adoption. With the exception of the “Proactive Upgrades for Hosting Capacity” item, the capital budget provided in this IDP similarly

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[69] Xcel Energy. *Response to Information Request No. 32(a), Topic: Proactive System Upgrades for DER Hosting Capacity.* (February 15, 2024).
[70] *Ibid.*
[71] IDP Appendix I at page 2.
[72] IDP Appendix A1 at page 49.

> only corresponds to meeting the needs of traditional load growth on the distribution system, not DER adoption. The "Proactive Upgrades for Hosting Capacity" item in the capital budget is intended to provide a high-level start to indicate costs that may be required to accommodate DER adoption but does not correspond to any of the DER forecast scenarios presented in this IDP.[73]

The Department is concerned with the inclusion of such a significant amount of funding without a clear demonstration of the need to justify the funding, as well as the justification for the proposed solution as the best alternative to address that need. To borrow the parlance of the Integrated Resource Plan process, Xcel has proposed the size, type, and timing of its solution, but this proposal lacks the establishment of the need and an evaluation of the alternatives to address the need. Xcel has identified proactive system upgrades, in the form of infrastructure investments,[74] in the proposed amounts beginning in 2025. As currently presented, it is unclear how Xcel has arrived at the selection of hosting capacity upgrades in the form of infrastructure investments, in the proposed amounts, on the proposed timeline.

The Department believes that key questions related to accommodating additional DER on Xcel's system have not been fully addressed, which limits the ability to evaluate the proposed funding. For example, what level of additional DER needs to be accommodated and on what timeline? Next, what alternatives can address the identified need? Finally, which alternative can cost-effectively address the identified need? The DER forecast scenarios presented in Xcel's IDP could provide a meaningful basis for this analysis; but as Xcel notes above, the proposed funding does not correspond to any specific forecast or targeted DER adoption level.

Xcel has also identified a number of measures that can reduce the need for or cost of distribution upgrades in Appendix I[75] and lays out its DER strategy roadmap in Appendix E.[76]

The Department is interested in how Xcel considers its proposed approach in light of these additional options to accommodate DER and their general exclusion from its proposed budget.

As noted above, Xcel's budget does not generally correspond to accommodating DER adoption. As Xcel describes in its IDP, its budget plan scenario "represents the minimum desired funding level for capacity work to meet immediate distribution system capacity needs."[77] The DER adoption scenarios then build from the budget plan with varying levels of DER adoption, namely the DER scenarios IDP

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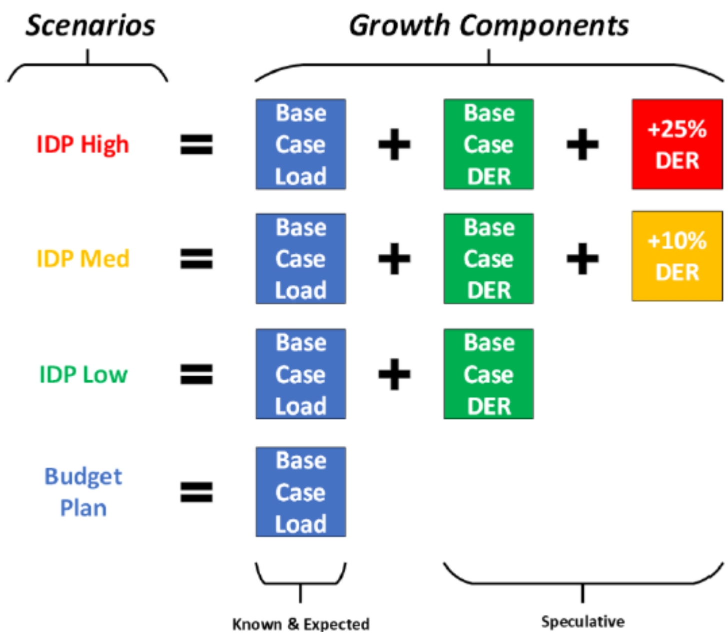
[73] Xcel Energy. *Response to Information Request No. 24(b), Topic: Load Forecasting.* (February 15, 2024).
[74] Xcel Energy. *Response to Information Request No. 32(b), Topic: Proactive System Upgrades for DER Hosting Capacity.* (February 15, 2024).
[75] IDP Appendix I at page 8.
[76] IDP Appendix E at page 2.
[77] IDP Appendix A1 at page 49.

Low, IDP Med, and IDP High. Xcel provides a useful illustration to clarify this distinction across forecast scenarios, which the Department provides in Figure 1, below, for clarity:

Figure 3. Xcel Figure A1 – 16: Scenario Definitions



Source: IDP Appendix A1 at page 50.

As Xcel subsequently notes, the IDP Low scenario "represents what is considered the base case, or expected adoption forecast for each DER technology forecasted."[78] As such, the budget is inherently mismatched with the accommodation of DER. Xcel provides a limited forecast of distribution system upgrades to accommodate DER in Appendix I, however this is limited to addressing the specific requirements of Minn. Stat. §216B.2425, the Community Solar Garden statute, and the Distributed Solar Energy Standard.[79] As such, Xcel's methodology solely reflected the IDP High scenario.[80]

The Department raises for consideration whether additional analysis, along the lines of that presented in Appendix I, to address additional types of DER and under various forecast scenarios could be a useful tool for stakeholders and the Commission to enhance the understanding of Xcel's budget and the accommodation of DER. The Department notes that the total budget included in Xcel's IDP, inclusive of the proposed hosting capacity upgrades, exceeds $4.2 billion for the years 2023 through 2028. Xcel's limited forecast of upgrade costs suggests the potential for significant incremental costs to accommodate DER at varying adoption levels. Understanding the extent of the potential costs for upgrades, alternative measures which can reduce upgrade costs, and how to reflect costs in the budget

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[78] *Ibid.*
[79] IDP Appendix I at page 1.
[80] IDP Appendix I at page 2.

to address targeted levels of DER adoption could enhance the evaluation of proposals such as the hosting capacity upgrades discussed throughout this section.

The Department requests Xcel discuss in reply comments the feasibility in future IDPs of conducting additional analysis of distribution system upgrade costs for additional types of DERs under various forecast scenarios.

Finally, as presented throughout the Department's response to Notice Topic 17, there are both concerns and optimism for the proactive upgrading of distribution system capacity to meet the needs of future load growth. It is essential that costs are allocated evenly across rate payers so that one group is not burdened by the actions of another without receiving any benefits. There are many solutions to allocate costs discussed throughout this section, and it is important that each of them receives further consideration and analysis to inform the Commission on how best to allocate costs.

The greatest cost of concern is meeting the challenge of building a resilient distribution system in the context of 300 percent load growth. Xcel has not provided a discussion of how it plans for future load growth despite a five-year IDP budget that is quickly increasing and its forecasting scenarios. The Department does not understand if future load growth is taken into consideration when age-related replacements are made, and if so, how far into the future Xcel plans for these upgrades. If Xcel looks at too short of a timeframe, this could result in duplicative capacity upgrades on the same feeders over the next 30 years. At the same time, building capacity to meet a forecast 30 years from now is also not practical or desirable. This is the balance Xcel must find, which is to plan for the future and to at least build in the capacity for future upgrades if they are not made in the present.

The Department welcomes a discussion from Xcel and the public about how forward-thinking Xcel should be when planning for the larger distribution grid it currently forecasts.

D. GRID MODERNIZATION: REQUIRED INFORMATION AND COST-BENEFIT ANALYSIS

Notice Topic 16.B: Feedback, comments, and recommendations on the following areas of Xcel's IDP: Grid modernization plans, including but not limited to a Distributed Energy Resource Management System (DERMS), Virtual Power Plants (VPP), Integrated Volt-Var Optimization (IVVO), and Distributed Intelligence (DI)

Notice Topic 19: Should the Commission require cost-benefit analysis for discretionary distribution system investments?

Xcel addresses grid modernization primarily in Appendices B1-B3, Appendix C, and Appendix D. In this section, the Department provides comments on the grid modernization information Xcel has provided. The Department does not address the merits of individual grid modernization projects but offers comments on the information Xcel has provided and on informational deficiencies thereof. The Department stresses the critical need for complete information regarding grid modernization in the

IDP, given the key role that grid modernization investments play in achieving cost-effective policy objectives related to integration of DERs and electrification, among other goals—central to the integrated planning process in Minnesota.

i. Grid Modernization as a Key Policy Objective in Minnesota

(a) Statutory Filing Requirements

The Minnesota legislature established grid modernization as a goal for the state's utilities through enumerating filing requirements and providing for the potential of favorable cost recovery of grid modernization investments.[81] The first grid modernization plan filing requirement in Minnesota came in 2015 with new legislation requiring utilities that own transmission lines and are operating under multi-year rate plans (MRP) to address grid modernization and planning in their newly mandated biennial transmission plans.[82,83] Initially, only Xcel was subject to this requirement as none of the other transmission-owning utilities were operating under MRPs. Specifically, Minn. Stat. §216B.2425, Subd. 2(e) and Subd. 8 (the "Grid Modernization Statute") requires that, as a component of its mandatory biennial transmission and distribution plans, a qualifying utility such as Xcel shall:

- [I]dentify investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies; and

- [C]onduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources.[84]

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[81] Concerning cost recovery, the Minnesota legislature has encouraged electric utilities to modernize their grids through (a) granting permission for automatic rate adjustments (multi-year rate plans); and (b) charging the Commission with the responsibility for approving grid modernization spending to be recovered in such rates through the established Transmission Cost Recovery (TCR) rider process. See Minn. Stat. § 216B.2425 subd. 3, and Minn. Stat. §216B.16, subd. 7b (the Transmission Cost Recovery (TCR) Rider Statute)

[82] In its August 7, 2018, Order in Docket No. E-002/M-17-776, the Commission directed Xcel to include its Grid Modernization report with its IDP

[83] Also in 2015, the Minnesota Commission opened a proceeding to investigate grid modernization issues. See MN PUC. Proceeding No. 15-556.

[84] Minn. Stat. §216B.2425, Subd. 2(e) and Subd. 8.

Subsequently, the Grid Modernization Statute was amended to include the requirements that Xcel's IDP provide:

- [A] forecast of distribution system upgrades necessary to accomodate [sic] the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects including energy storage systems;
- [A]n evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and
- [A] discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.

(b) Commission Filing Requirements

As discussed in Section A, the Commission has expanded on statutory filing requirements for grid modernization through its development of more extensive IDP requirements relating to grid modernization. Most significantly, the Commission requires that Xcel provided comprehensive information about grid modernization investments expected to occur in the next five years as part of the "5-Year Action Plan" that is itself a component of the mandated "Long-Term Distribution System Modernization and Infrastructure Investment Plan."

Per the Commission's IDP filing requirements, the 5-Year Action Plan "should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5 years."[85] The filing requirements also establish the need for clear statement of the objectives of individual projects and detailed alternatives analysis.[86] Further, the Commission requires that for each grid modernization project included in the 5-Year Action Plan, "Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel should provide all information used to support its analysis."[87] Continued discussion of these grid modernization filing requirements is provided in Section 0.

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[85] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2).
[86] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2.c).
[87] 2023 Notice of Comment at page 8 (IDP Filing Requirement D.2.k).

ii. Grid Modernization Information Missing from Xcel's IDP

(a) Detailed Information Missing from the 5-Year Action Plan

The Department finds that Xcel has not met its obligation to provide detailed information about near-term grid modernization investments through the 5-Year Action Plan. Though Xcel appears to anticipate moving forward with DI, DERMS, and potentially, a successor ADMS system within the five-year window of the Action Plan, the Company has not provided a sufficiently detailed evaluation of these investments, and it has neglected to provide cost-benefit analyses—a key omission.[88]

As already stated in Section A, the Department recommends that the Commission direct Xcel to refile Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects. Xcel should further be required to make any other necessary modifications to its IDP to reflect the necessary changes to Appendix C.

In the Department's view, Xcel should include in its IDP cost and benefit details and other required information on investments anticipated within the next five years to the maximum extent possible. Otherwise, there is a risk that the Company will move ahead with these investments and cost recovery requests without subjecting these investments to comprehensive review in the *integrated* context that is the IDP proceeding. The risk of inadequate or uneven review of grid modernization proposals is further exacerbated by the complex regulatory landscape, where the Company may have the option of choosing between multiple different cost recovery pathways, including through base rates and various rider alternatives. Review of grid modernization plans in an *integrated* context is particularly important because these investments are categorically different from traditional utility infrastructure—characterized by their interdependence and interactivity with other grid components, and by their optionality.

(b) Other Required Information on Grid Modernization Missing from IDP

In its final Order in Xcel's last rate case, the Commission accepted the Department's recommended additional grid modernization filing requirements to provide, with all future grid modernization proposals, "a road map with all planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernizations costs and all anticipated future grid modernization costs."[89] The Department finds that the while the "Illustrative Long-Term Grid Modernization Plan" provided by Xcel in several places in its filing does satisfy the "road map" requirement,[90] Xcel has not provided the required detail on historical grid modernization expenditures.

The Department therefore recommends that the Commission clarify its requirement that Xcel comply with the additional grid modernization filing requirements established by the Commission in Xcel's last rate case by providing both a roadmap of planned and contemplated future grid modernization

[88] 2023 IDP, Appendix C at pages 5-6 and, Figure C at page 12.
[89] Docket No. E-002/GR-21-630, Findings of Fact, Conclusions, and Order at page 146.
[90] See, for example, IDP at page 35.

investments and a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs with its IDP.

iii. Assessment of FLISR Information Provided in IDP and the Need for Detailed Reliability Performance Data

Since 2021, Xcel has deployed **[TRADE SECRET DATA HAS BEEN EXCISED]**[91] The Company plans on installing around 600 devices on 200 feeders through 2027.[92] Consisting primarily of automated reclosers and switches,[93] FLISR devices are intended primarily to improve customer reliability and will also provide operating data that the Company says will be useful for distribution planning purposes.[94]

(a) Analysis of Compliance with Relevant Commission Orders for FLISR

In its final Order in Xcel's last rate case, the Commission issued several directives to Xcel relating to reporting on the reliability improvements from FLISR, including the following:

- Xcel must track and report on reliability performance for circuits equipped with FLISR as recommended by the Department.[95]
- The Commission finds that any future FLISR cost recovery may be based on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR.[96]
- Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.[97]

In its IDP, Xcel claims to comply with Order Point 27.b by first describing, qualitatively, FLISR's ability to improve reliability, and second, giving one example of an installed FLISR device that delivers reliability benefits on December 15, 2022.[98] The Company did not provide any additional data regarding reliability improvements due to FLISR in response to IRs.[99]

Xcel argues that it is not required to provide reliability performance for circuits with FLISR in the IDP because "[t]he Commission Order does not require the Company to report this information in the

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[91] Attachment C provides Xcel's trade secret responses to all Department Information Requests.
[92] IDP, Appendix B1 at page 18.
[93] IDP at page 33.
[94] IDP, Appendix B1 at pages 18-19.
[95] Order Point 25.
[96] Order Point 26.
[97] Order Point 27b.
[98] IDP, Appendix B1 at page 21.
[99] **[TRADE SECRET DATA HAS BEEN EXCISED]**

Integrated Distribution Plan."[100] While it is true that the Commission only explicitly required Xcel to provide a "summary of FLISR's reliability results" in the IDP through its rate case Order, the Department submits that the imperative of understanding FLISR's contribution to reliability, which is key to evaluating Xcel's grid modernization plans and overall reliability improvement programs, will best be served by Xcel providing granular FLISR reliability impacts.

The Department recommends that the Commission articulate the requirement that Xcel include a report of reliability performance for circuits equipped with FLISR, consistent with the Department's recommendations in the last general rate case.

iv. Need for Detailed Reliability Performance Information and Specific Reliability Performance Targets in the IDP

Improving reliability is a core goal for Xcel's grid modernization initiatives,[101] and reliability also figures prominently in Xcel's broader distribution investment plans.[102] Yet, the Company has not associated its investment plans with specific reliability performance objectives.[103]

The Department therefore recommends that the Commission require Xcel to include in its IDP specific reliability goals, and to specify, and quantify to the extent practicable, other key objectives which its proposed investments support. To the extent possible, the Company should also indicate the specific contribution that individual proposed investments will make to the achievement of reliability improvements and other specific goals.

v. Assessment of Distributed Intelligence (DI) Information Provided in IDP

The DI proposal in the 2023 IDP that is provided in Appendix J covers grid-facing use cases including high impedance detection, location awareness, and EV detection and customer-facing use cases such as real-time energy usage, historical usage costs, and customer recommendations based on usage patterns and available rates. The rollout of AMI influences the programs used by DI. Xcel has deployed 512,250 meters as of 2022, with a goal of fully deploying 1.4 million meters by 2025.[104]

(a) Compliance with IDP Filing Requirements and Commission Order Points Concerning the DI Proposal

The Commission declined to allow cost recovery to Xcel when the Company last brought forward a proposal for DI in conjunction with its last general rate case, Docket No. E-002/GR-21-630. The final Order in that case included the following Order Point on DI: "The Commission rejects Xcel's proposal

[100] Response to DOC IR-12.
[101] See, for example, 2023 IDP at page 4.
[102] See the discussion in Section B of these comments on reliability spending beginning on page 12.
[103] See response to DOC IR-25.
[104] 2023 IDP, Appendix B1 at page 11.

for the Distributed Intelligence program without prejudice and direct [sic] Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement ."[105]

While the Department finds that Xcel's proposal has been rendered consistent with the Company's Colorado settlement, the Department is concerned about other missing information.

As noted above, Xcel believes that it is not obligated to provide a cost-benefit analysis with its DI proposal since it is not requesting cost recovery in the instant IDP proceeding,[106] and the Company also points to the cost-benefit analysis already filed for DI in the rate case docket.[107] Yet, in the Department's view, the Company is remiss for not having included an updated cost-benefit analysis to support its DI proposal here. Indeed, without a cost-benefit analysis, the information put forward on DI does not meaningfully qualify as a "proposal." As articulated before, the Department's view is that the Company should be providing cost-benefit analyses with its near-term grid modernization plans as a matter of course—further supporting the need for the Company to have provided a cost-benefit analysis with its DI proposal in the instant proceeding. The Company's DI rollout is expected within the five-year window covered by the Action Plan, and the IDP filing requirements for the Action Plan clearly call for a cost-benefit analysis using the "best information [Xcel] has at the time."[108] If the "best" cost-benefit analysis is the one previously submitted in Xcel's last rate case, then the Department has serious concerns about the cost-effectiveness of DI.[109]

In its Order in the last rate case, the Commission stated that Xcel had "not met its burden to show that its proposed DI costs are just and reasonable."[110] The Commission stated that Xcel had not resolved underlying issues with its cost-benefit analysis provided with its previous DI proposal.[111] For Xcel to have fulfilled the mandate to refile its DI proposal in the instant IDP, it would have needed to include a discussion of the reasonableness of proposed DI costs as part of its proposal.

Xcel states that customers would receive the benefits of DI before the company seeks cost recovery.[112] However, it is not clear if the benefits received by Minnesota customers today will be included in the cost-benefit analysis Xcel will presumably conduct when it seeks cost-recovery. Additionally, Xcel will be evaluating its customer-facing DI program costs during an upcoming DSM (demand-side management) plan modification.[113] Overall, the Department is concerned with the diffuse approach to DI cost recovery that Xcel describes. In the Department's view, such an approach is likely to result in a

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[105] Order 21-630, Point 33 at page 158.
[106] 2023 IDP, Appendix J at page 18.
[107] 2023 IDP, Attachment B at page 9.
[108] 2023 Notice of Comment, page 8 (IDP Filing Requirement D.2.k)
[109] Cite to Company IR about cost-effectiveness of DI.
[110] Order 21-630 GRC at page 59.
[111] Order 21-630 GRC at page 59.
[112] 2023 IDP, Appendix J at page 33.
[113] Xcel Response to MN COMM Information Request No. 18, c.

fragmented and even siloed approach to review, wherein the overall merits of the Company's DI program are challenging to assess.

The Department therefore recommends that the Commission direct Xcel to refile its proposal for DI with a complete cost-benefit analysis that demonstrates that DI is cost-effective. If the Company cannot demonstrate cost-effectiveness on narrow quantitative grounds, then it must provide justification for why it believes that the costs of DI should nonetheless be allowed for recovery.

(b) Compliance with IDP Filing Requirements and Commission Order Points on a Comprehensive Framework for HAN, AMI, and AMI-DI

The Commission's Order in the last Transmission Cost Recovery proceeding directed Xcel to include in the instant IDP a "comprehensive framework" for assessing:

a) HAN, AMI and AMI-DI specifications and related customer data access policies.
b) Bring-your-own device HAN requirements and terms.
c) Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN.
d) Methods to provide customers equal access to the level of data available to the utility.
e) A summary of industry customer data access standards."[114]

At first pass, the Department finds that Xcel has met the above requirements relating to a comprehensive framework. However, the Department has not conducted a survey of industry customer data access standards to inform its evaluation of the data standards proposed by Xcel. While the Department believes that the standards put forward by the Company are reasonable, the Department reserves the opportunity to provide critical feedback in its Reply Comments in this proceeding.

E. NON-WIRES ALTERNATIVES ANALYSIS

Notice Topic 16.A: Feedback, comments, and recommendations on the following areas of Xcel's IDP: Non-Wires Alternative Analysis

i. Overview of IDP Filing Requirements and Order Points

There are three primary IDP requirements pertaining to NWAs. First, IDP Filing Requirements E.3.1 requires Xcel to "provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For

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[114] Order 21-814, Point 17 at pages 10-11.

any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value."[115]

Second, IDP Filing Requirement 3.E.2 sets forth the requirements for the information Xcel must provide related to NWA analysis, which includes:

- Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
- A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
- Cost threshold of any project type that would need to be met to have a nontraditional solution reviewed
- A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.[116]

Third, IDP Requirement 3.A.5.d pertains to how Xcel's distribution system planning is coordinated with its Integrated Resource Plan and requires Xcel to include a discussion for how it is "improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs."[117]

The Department finds that Xcel generally meets the IDP requirements related to NWA analysis, except for IDP Requirement 3.E.1 described in more detail below.

In addition to the IDP filing requirements, there are several Order points that pertain to NWA analysis as follows:

- July 23, 2020, Order[118] requires Xcel to engage stakeholders in further advancing the Company's NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.
- July 26, 2022, Order[119] requires Xcel to use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting and required Xcel to make a compliance filing that outlines key difference between its Colorado and Minnesota distribution system planning processes.

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[115] Minnesota Public Utilities Commission*, Minnesota Integrated Distribution Planning Requirements, Docket No. 21-694 and 17-879*, (December 8, 2022). *Hereinafter* December 2022 Order at page 9.
[116] December 2022 Order at page 10.
[117] December 2022 Order at page 3.
[118] Docket No. E002/M-19-666, July 23, 2020, Order
[119] Docket No. E002/M-21-694, July 26, 2022, Order

The Department finds that Xcel met the requirements set forth in these Order points. The Company engaged with stakeholders to identify ways to advance NWA analysis[120] and applies the WACC and societal discount rate in the NWA analysis.[121]

ii. Areas of Non-Compliance With IDP Filing Requirements and Order Points

The Department finds that Xcel only partially complies with IDP Requirement 3.E.1. In Table F-1 in Appendix F of the 2023 IDP, Xcel lists 16 traditional distribution system projects in the filing year and subsequent five years that it anticipates will have a cost greater than $2 million dollars. For each project, Xcel provides the budgeted cost per year and the total from 2024-2028.[122]

However, Xcel does not fully comply with the second part of IDP Requirement 3.E.1, which requires that Xcel provide "an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value" for "any forthcoming project or project in the filing year, which cost two million dollars or more."[123] The Department understands this requirement to mean that Xcel should provide an analysis for each of the 16 traditional distribution projects identified in Table F-1. However, Xcel only provides a summary of this analysis for the three projects that pass its initial NWA analysis screen and result in a feasible solution.[124] For the remaining 13 projects, the only information Xcel provides is the total cost of the traditional project in Table F-3. Xcel does not include any discussion related to why an NWA is not feasible for each of those projects.[125] Only in response to Information Requests does Xcel provide an explanation for why projects were listed as "not feasible."[126] In the Company's response, it indicates that the projects listed as not feasible had at least one risk for which a battery state of charge could not be high enough to address the load reduction requirement in the first hour it was needed.[127]

The Department recommends that the Commission require Xcel to address this deficiency. Even if an NWA is determined to not be feasible, this does not excuse Xcel from the requirement of providing a description of the analysis. For projects where Xcel determines an NWA is not feasible, it should include evidence to support this conclusion.

While the Department concludes that Xcel provided the necessary information to comply with IDP Filing Requirement 3.E.2, IDP Filing Requirement 3.A.5.d, and the Order points related to NWA analysis, it finds that there are several improvements that can be made to ensure that NWAs are fully considered within distribution planning.

[120] 2023 IDP Appendix F at page 21.
[121] 2023 IDP Appendix F at page 25.
[122] 2023 IDP Appendix F at pages 3-4.
[123] December 2022 Order at page 9.
[124] 2023 IDP at Appendix F at page 30.
[125] 2023 IDP Appendix F at Table F-3
[126] Xcel Energy*. Response to Information Request No. 52(a), Topic: NWA.* (February 16, 2024).
[127] *Ibid*.

iii. Project Types Considered for NWAs

IDP Filing Requirement 3.E.2 requires Xcel to include information on distribution system projects that would lend themselves to non-traditional solutions (i.e. load relief or reliability).[128] Within Appendix F of the 2023 IDP, Xcel provides a description of three project types, which include mandates, asset health and reliability, and capacity. Xcel concludes that capacity-related distribution system projects are best suited for NWAs.[129]

The Department finds that limiting NWAs to capacity-related projects reduces the potential for NWAs and does not align with practices in other jurisdictions. For example, the Distribution Investment Deferral Framework in California, which governs rules for NWAs, considers distribution capacity, voltage support, reliability, and resilience related projects as all being well-suited for non-wires solutions.[130] Similarly, investor-owned utilities in New York consider load relief and reliability most conducive to NWAs.[131] In addition, Rhode Island considers NWAs for electric distribution needs that are not related to asset condition issues.[132]

For these reasons, the Department recommends that Xcel be required to consider NWAs for all non-asset-based distribution system projects.

iv. Screening Process

IDP Filing Requirement 3.E.2 requires Xcel to include a discussion of a proposed internal screening process to determine that non-traditional alternatives are considered prior to any decision to make a distribution system investment.[133] Xcel complies with this requirement and provides a detailed discussion of its screening process within Appendix F of the 2023 IDP. Xcel also includes several modifications related to improving NWA analysis in accordance with IDP Filing Requirement 3.A.5.d.

The Department supports several of the modifications Xcel made to its screening process, including the expansion of the costs and benefits included in the NWA analysis as defined in the *National Standard Practice Manual*[134] and the use of both the weighted average cost of capital (WACC) and societal discount rate.[135] However, the Department has concerns with Xcel's decision to change its screening

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[128] December 2022 Order at page 10.
[129] 2023 IDP Appendix F at pages 8-10.
[130] California Public Utilities Commission, *Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework*, R. 14-08-013, (June 30, 2017). Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M191/K623/191623481.PDF.
[131] Prince, Jason, Jeff Waller, Lauren Shwisberg, and Mark Dyson. *The Non-Wires Solutions Implementation Playbook: A Practical Guide for Regulators, Utilities, and Developers*. Rocky Mountain Institute, (2018). Page 57. Available at: http://www.rmi.org/insight/non-wires-solutionsplaybook/.
[132] Rhode Island Energy, *2024-2026 System Reliability Procurement Three-Year Plan*, Docket No. 23-47-EE at page 21.
[133] December 2022 Order at page 10.
[134] Woolf, Tim, et al. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, (2020). Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf
[135] Order Point 3 of the Commission's July 26, 2022, Order in Docket No. E002/M-21-694 requires the Company to use both weighted average cost of capital (WACC) and societal discount rate in its NWA analysis.

process from considering the full lifetime of an NWA solution to an assumed five-year deferral period.[136] The Department also finds the screening process could be further improved if Xcel considered additional DERs—including incremental energy efficiency and demand response—as potential NWA solutions within its initial screening process. The Department discusses each of these points in more detail below.

a. Deferral Period

In prior NWA screenings, Xcel assumed utility ownership, maintenance, and operation of the NWA solution and accounted for the associated costs and benefits over the full useful life of the NWA solution. Now, Xcel assumes the risk associated with a distribution system project is deferred for only a five-year period. The Company then prorates the costs and benefits of the NWA solution to match the deferral need of five years. Under this approach, Xcel assumes that the NWA third-party providers would pay the full cost to design, build, and install the DERs. The Company would then compensate the NWA provider based on the DER's contribution to the deferral need. The Company's justification for this change is that it will better align with the way it might structure future NWA load reduction contracts with third-party providers and improve the cost-benefit screening performance of potential NWA projects.[137]

The Department concludes that, while this approach may be suitable for internal screening purposes to assess the potential viability of a project for an NWA solicitation, it may not translate into an effective payment structure for third-party NWA providers and may not sufficiently incentivize new DER investments, especially if a project can be fully avoided or deferred for more than five years.

For example, developers of long-lived DERs with high upfront costs (i.e., solar and storage) will seek an investment stream for the 10–20 year life of the asset. A payment stream associated with only a five-year deferral window may not be sufficient to attract investment in new DERs and instead result in NWA solutions that leverage only existing resources. In addition, the DER developer would face uncertainty and risk related to whether the NWA payment will be extended beyond the initial five-year deferral period.

For these reasons, the Department encourages Xcel to reexamine the deferral period and payment structure as it develops NWA solicitations in the future.

b. Incorporation of Incremental energy efficiency and demand response

The Company's initial screening process first determines the list of distribution system projects potentially suitable for NWA solutions and then identifies the MW and MWh need to address the risk associated with each traditional project and the Avoided Revenue Requirement (ARR) split. Once the

[136] 2023 IDP Appendix F at page 20.
[137] 2023 IDP Appendix F at page 20.

ARR split is determined, Xcel identifies the percentage of total solar and battery storage that would be required to solve the system need.[138]

The problem with this approach is that Xcel only considers two DER types, solar and storage, as potential NWA solutions. The Company does not consider additional energy efficiency and demand response beyond current levels. While Xcel states it applies "focused [demand response] in an effort to reduce the load" prior to the allocation of the ARR to solar and storage,[139] the Company explains that "focused [demand response]" in this case only represents existing customer enrollment.[140] Similarly, Xcel does not consider energy efficiency as an NWA component, stating that energy efficiency is "common to both the traditional projects as well as the NWAs."[141]

The Department has several concerns with this approach. First, while the costs of solar and storage have declined in recent years, energy efficiency and demand response remain the least-cost options to reduce energy and demand.[142] If Xcel is not considering the contribution of incremental energy and demand savings that can be achieved from increasing participation in existing programs or from new offerings, it may result in a larger and more costly NWA solution.

Second, exclusion of energy efficiency and demand response may reduce the number of potentially feasible projects. In response to the Department's Information Request, which asked whether additional energy efficiency would change the outcome of candidate distribution system projects determined to be not feasible for NWA solutions, Xcel stated that "[a]dditional energy efficiency, provided that such incremental energy efficiency could be determined, could have an impact on the outcome depending on how much energy efficiency is incrementally available."[143]

It is unclear whether the addition of incremental energy efficiency and demand response in the initial NWA screen could allow for more projects to be considered feasible for NWA analysis. For example, the Company notes that since it began screening for NWA solutions in 2019, it observed traditional projects that were not actually feasible due to risks existing "during hours when solar would not be generating and batteries could not have enough hours or capacity."[144] However, the Company did not consider whether energy efficiency and demand response could have helped to alleviate risk during the hours when the other DERs are not able to provide load relief.

The Company argues that it did not consider geotargeted energy efficiency for potential NWAs because it lacks information related to customer BTM equipment and incremental energy efficiency potential

[138] 2023 IDP Appendix F at pages 16-17.
[139] 2023 IDP Appendix F at page 5.
[140] Xcel Energy*. Response to Information Request No. 49(a), Topic: NWA.* (February 15, 2024).
[141] 2023 IDP Appendix F at page 43.
[142] Frick, Natalie Mims, Sean Murphy, Chandler Miller, and Margaret Pigman. *Still the One: Efficiency Remains a Cost-Effective Electricity Resource.* (2021). Available at: https://emp.lbl.gov/publications/still-one-efficiency-remains-cost.
[143] Xcel Energy*. Response to Information Request No. 52(b), Topic: NWA.* (February 16, 2024).
[144] 2023 IDP Appendix F at page 13.

for specific customers.[145] However, targeted energy efficiency and demand response solutions have been included in NWAs across the country. For example, a recent study by Smart Electric Power Alliance, Peak Load Management Alliance, and E4TheFuture identified six recent NWAs that utilized targeted energy efficiency and/or demand response as part of the NWA solution.[146] The most successful example can be found in Con Edison's Brooklyn Queens Demand Management (BQDM) initiative in New York. The BQDM pilot combined energy efficiency, demand response, distributed generation and solar to defer the need for a substation upgrade. National Grid in Rhode Island also utilized energy efficiency and demand response in its NWA pilot in Little Compton and Tiverton. National Grid identified existing and new energy efficiency measures that had load shapes matching the hours of system need and provided enhanced financial incentives to customers located on the feeders where load reduction was needed to realize deferral of a substation.[147]

The Department recommends that Xcel modify its initial NWA analysis to account for the potential of incremental energy efficiency and demand response.

Leveraging existing energy efficiency and demand response programs as part of an NWA solution has shown to be a cost-effective approach. The Company could conduct a preliminary examination of existing energy efficiency and demand response programs and the associated load shapes of the measures. This information could be obtained from Energy Conservation & Optimization (ECO) evaluations or estimates could be derived from the Minnesota Energy Efficiency Potential Study.[148] The Company could then identify the class of customers (i.e., residential, small commercial, industrial) on the feeders associated with the distribution system project to assess whether incremental participation in existing programs could potentially provide additional load relief.

The purpose of this recommendation is not to require Xcel to determine with 100 percent certainty that energy efficiency and demand response can address risks not solved by storage and solar. The purpose is to avoid a determination that a project is not feasible when there could be a possible solution to address a portion of the risk with incremental energy efficiency and demand response, and therefore not put out to bid for an NWA.

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[145] Xcel Energy*. Response to Information Request No. 49(b), Topic: NWA.* (February 15, 2024).
[146] Smart Electric Power Alliance, Peak Load Management Alliance, and E4TheFuture. *Non-Wires Alternatives: Case Studies from Leading U.S. Projects. (2018)* at 16. Available at: https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/.
[147] The Narragansett Electric Co. d/b/a National Grid - *2019 System Reliability Procurement Report (SRP)*, Docket No. 4889. Appendix 3 –Tiverton NWA Pilot Evaluation Deliverables from Opinion Dynamics Corporation.
[148] Minnesota Energy Efficiency Potential Study: 2020–2029. Prepared for Minnesota Department of Commerce, Division of Energy Resources by the Center for Energy and Environment, Optimal Energy, and Seventhwave. (2018).

v. Future NWA Pilot

The Company identifies three potentially viable and cost-effective projects resulting from its NWA analysis. However, Xcel states that because these projects do not have in-service dates until 2028, the Company will determine next steps in its next Annual Update filing in 2024.[149]

The Department is concerned with the delay in moving forward with solicitations for the three projects given the supply chain issues across the energy industry. Throughout the 2023 IDP, Xcel notes supply chain issues. For example, the Company indicates that "[d]ue to the long lead time of some equipment, orders must be placed one and half to four years in advance."[150] However, Xcel does not appear to be concerned with supply chain issues as they pertain to NWA solutions. The Company states that any potential risks related to missing in-service dates for feasible NWA projects are "largely addressed by only looking at NWA projects in years 3-5 of this IDP."[151] The Company further notes that while there is an increase in lead times for procuring equipment such as substation transformers, this is not a concern for the three potential projects as they do not require a substation transformer.[152]

While Xcel accounts for the impact of supply chain issues on traditional "wires" solution for the three projects, Xcel is not accounting for the potential supply chain issues facing the third-party NWA solution providers. For example, there have been widespread supply chain issues related to energy storage equipment, which Xcel considers to be one of the primary technologies for NWA solutions.[153]

The Department recommends Xcel account for the potential long lead time NWA providers may face in developing the NWA solution and not delay solicitation for bids from the marketplace.

F. RESILIENCY PERFORMANCE TRACKING AND MICROGRIDS

Notice Topic 22: What should the Commission consider or address related to enhancing the resilience of the distribution system within Xcel's IDP?

In this section, the Department addresses two sets of issues in the domain of resiliency—defining and tracking resiliency performance and setting resiliency performance targets, and microgrids as a specific approach to targeted resiliency enhancement.

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[149] Xcel Energy*. Response to Information Request No. 47, Topic: NWA.* (February 15, 2024).
[150] Xcel Energy*. Response to Information Request No. 29(a), Topic: Supply Chain Issues and Procurements.* (February 15, 2024).
[151] Xcel Energy*. Response to Information Request No. 43, Topic: NWA.* (February 15, 2024).
[152] *Ibid*.
[153] Maisch, Marija. *Transformer shortages: New bottleneck of the energy storage supply chain.* 2023. PV Magazine. Available at: https://www.pv-magazine.com/2023/10/31/transformer-shortages-new-bottleneck-of-the-energy-storage-supply-chain/.

1. Resiliency Performance Metrics

Xcel identifies resiliency as a key priority in its 2023 IDP. The Company ranks "Maintaining and Enhancing Reliability and Resilience" among its four strategic priorities in developing its long-term infrastructure plans.[154] Xcel reports that it has made efforts at improving system resiliency through investments in backhaul and private LTE, FLISR, DERMS, and security measures.[155]

The Department is concerned, however, that Xcel's resiliency strategy is not sufficiently differentiated from its approach to reliability. In response to an information request, the Company provided a distinct definition for resiliency as "the system's ability to withstand, endure, and recover from significant events that can create widespread outages and result in long-duration restoration times."[156] However, the Company does not separately track resiliency and does not appear to target resiliency in a sufficiently intentional or precise fashion through its investment plans. Instead, the Company appears to believe that tracking reliability performance, and making investments targeted to improve reliability, will in turn enhance system resiliency. The Company notes that tracking SAIDI and SAIFI, which are "directionally correlated to resiliency," will provide an indication of resiliency performance.[157] Xcel further explains that it plans to improve system resiliency "by investing in projects that allow us to maintain reliable service for our customers and to harden our system against extreme weather events, as appropriate."[158]

The Department agrees that SAIDI, SAIFI, and other traditional reliability metrics may provide an indication of resiliency performance, but stresses that the focus for resiliency should be on the non-weather-normalized versions of these metrics that include Major Event Days (MEDs).[159] The Department notes that other jurisdictions track SAIDI and SAIFI with major events as measures of resiliency. In Massachusetts, for example, National Grid uses reliability metrics with MEDs to gauge the efficacy of its investments in resiliency.[160]

The Department recommends that the Commission direct Xcel to develop a suite of metrics to track resiliency, including SAIDI and SAIFI, MEDs, and other metrics to the extent warranted.

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[154] Xcel Energy. 2023 Integrated Distribution Plan, Docket No. E002/M-23-452. Filed November 1, 2023 at page 4.
[155] Xcel Energy. 2023 Integrated Distribution Plan, Docket No. E002/M-23-452. Filed November 1, 2023. Appendix B1 at pages 16, 21, 24 of 50, and Appendix B2 at page 2.
[156] Xcel Energy. Information Request No. 26, Topic: Resiliency. February 5, 2024.
[157] Xcel Energy. Information Request No. 26, Topic: Resiliency. February 5, 2024.
[158] Xcel Energy. Information Request No. 26, Topic: Resiliency. February 5, 2024.
[159] Major Event Days are power outage scenarios often caused by severe weather. The protocol for determining the MED threshold is per IEEE 1366.
[160] National Grid. Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future, September 2023 at page 92.

For reference for developing this suite of metrics, the Department points to the resiliency report series published by Sandia National Laboratory in 2021, and specifically, to the report from this series focusing on the development of resiliency metrics.[161]

Sandia defines resilience as "The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions."[162] The report clarifies that while reliability is primarily about the grid's functionality on a day-to-day basis, resiliency has to do with the grid's ability to mitigate the impact of severe events on customers and critical services.[163] Identifying at-risk customers and geographies is thus crucial in measuring resiliency performance and targeting resiliency investments effectively.

One specific approach to tracking resiliency that is discussed in this report is to separately track performance during major events for different tiers of customers and for different regions.[164] Customer tiers should be established according to the consequences of losing power. The Sandia report recommends critical customer services such as hospitals, water treatment facilities, and grocery stores be included in the first tier, vulnerable populations such as those with high health risks or low mobility included in the second tier, and all others included in the third tier. The report further recommends categorizing geographic regions into high-risk, medium-risk, and low-risk tiers depending on the consequences of an outage. Segmenting resiliency performance metrics in this way could allow Xcel to optimize resiliency investments.[165]

Table 9 shows Sandia's suggests for different measurements to track before and during major outage events for each customer tier, geographic tier, and event. Collecting a wide swath of data in each category allows utilities to gain a better understanding of how major outage events affect different groups.

The Department recommends that the Company propose a set of resiliency performance metrics such as Sandia's that encompass broad system impacts, in addition to SAIDI and SAIFI.

[161] Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments, May 2021 at page 10.
[162] Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments, May 2021 at page 10.
[163] Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments, May 2021.
[164] Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments, May 2021.
[165] Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments, May 2021 at pages 21-27. Available at: https://www.synapse-energy.com/sites/default/files/Performance_Metrics_to_Evaluate_Utility_Resilience_Investments_SAND2021-5919_19-007.pdf

Table 9. Sandia National Laboratories Grid Resilience Performance Metrics Menu

Category	Customer Tier	Geographic Tier	Event
Report before a major outage event	• Number of customers, percent of total • Number of critical customers, percent of total • Load, percent of total load • Number of island-able resources	• Number of substations and critical substations • Number of feeders and critical feeders • Number of customers served per substation and feeder	• Frequency, number of events • Average duration of each event • Event probability
Report during a major outage event	• Number of affected customers and critical customers • Departed Customers • Departed Load • Number of island-able resources that functioned during event	• Number of affected substations and critical substations • Number of affected feeders and critical feeders • Percent of affected substations and feeders of total	• Duration of event • Utility staff impacts (injuries or deaths, percent affected) • Utility infrastructure impacts ($ damages) • Non-staff impacts (injuries or deaths, percent affected) • Non-utility infrastructure impacts ($ damages to customers, services, etc.)

Source: Sandia National Laboratories. Performance Metrics to Evaluate Utility Resilience Investments. May 2021. Pages 19-27.

2. Performance Metrics and Targets for Microgrids

The need for resiliency performance metrics is all the more relevant in light of Xcel's recent receipt of $9 million dollars from the Grid Resilience and Innovation Partnership (GRIP) program to move forward with the Company's Resilient Minneapolis Program (RMP). The RMP is a pilot program to install microgrid infrastructure in three historically underserved communities in Minnesota. After initially being approved, the Company withdrew the program when implementation costs grew to exceed the approved cap.[166] Now, with GRIP funding from the *Bipartisan Infrastructure Law*, the Company will file again for approval to proceed with the RMP.

In the initial 2021 proceeding, the Department raised concerns about the scale of benefits relative to the program cost and vagueness about the goals of the project in the context of the Company's long-term plans.[167] The Department recommended that the Commission "should grant certification for a grid modernization investment only when the proposal and cost-benefit analysis shows that, by a preponderance of the evidence on the record, the proposed investment will be in the public interest and there is no more reasonable and prudent alternative to the proposed grid modernization investment."[168]

In Order Point 8 of the Commission's Order accepting the 2021 IDP, the Commission required Xcel to develop "a set of evaluation metrics that allow comparison to other resilience offerings" for the RMP.[169] In its December 2022 RMP annual report, the Company proposed seven resiliency evaluation metrics, including hosts' experience of RMP, description of islanding events, description and quantification of solar, BESS, and microgrid dispatch, fossil generation, HVAC and energy efficiency implementation, frequency of sustained interruptions, and duration of sustained interruptions.[170] While this set of proposed metrics represents a good start for tracking resiliency, it is lacking in measures of system performance during major outage events.

The Department recommends that Xcel further develop and clarify its resiliency metrics for the RMP to includes measures of system performance during major outage events.

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[166] Minnesota Public Utilities Commission. Order Approving Withdrawal and Requiring Filing, Docket No. E002/M-21-694, September 21, 2023.
[167] Minnesota Public Utilities Commission. Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project, Docket No. E002/M-21-694, July 26, 2022, at page 9.
[168] Minnesota Public Utilities Commission. Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project, Docket No. E002/M-21-694, July 26, 2022, at page 9.
[169] Minnesota Public Utilities Commission. Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilient Minneapolis Project, Docket No. E002/M-21-694, July 26, 2022, at page 13.
[170] Xcel Energy. Resilient Minneapolis Project Annual Report Integrated Distribution Plan, Docket No. E002/M-21-694, December 1, 2022, at page 18.

G. INITIAL LOADSEER FORECASTING RESULTS AND METHODOLOGY

Notice Topic 16.D: Feedback, comments, and recommendations on the following areas of Xcel's IDP: Initial LoadSEER forecasting results and methodology

The Commission's Notice at point 16d states that the comments on Xcel's "Initial LoadSEER forecasting results and methodology" are to be made at this time.

Xcel uses LoadSEER for medium- to long-range load forecasting at a very detailed level—distribution feeders and substation transformers. The Department reviewed publicly available information on the LoadSEER model.[171] Based upon the public information and Xcel's discussion in Appendix A1 of the Petition, the Department concludes that the LoadSEER model that is used by multiple utilities across the country and that LoadSEER should be able to perform basic forecasting.

Figure A1 – 19 of the Petition shows an example of forecast outputs by substation transformer. Several other figures in Appendix A1 also show various forecast-related data. However, without the base forecast data, explanation of changes to the input data, variables that were considered, the forecast outputs, statistical measures of the forecast's accuracy, and so forth, it is not possible to provide technical comments on Xcel's forecasting results and methodology.

Therefore, the Department recommends that, in the next IDP, Xcel provide, for one of the LoadSEER forecasts:

- ***a. a complete list of the data sets used in making the LoadSEER forecast, including:***
- ***b. a brief description of each data set and***
- ***c. an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer);***
- ***d. a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:***
  - ***the nature of the adjustment,***
  - ***the reason for the adjustment, and***
  - ***the magnitude of the adjustment;***
- ***e. a discussion of each essential assumption made in preparing the LoadSEER forecast, including:***
  - ***the need for the assumption,***
  - ***the nature of the assumption, and***
  - ***the sensitivity of forecast results to variations in the essential assumptions;***
  - ***an equation showing the LoadSEER forecast model:***

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[171] Two examples are: LoadSEER Fact Sheet, "Improve Your Power Flows With Granular Forecasting" and LoadSEER Pacific Gas and Electric Case Study, 2012. Available at: https://integralanalytics.com/wp-content/uploads/2022/10/LoadSEER-by-Integral-Analytics.pdf and https://integralanalytics.com/wp-content/uploads/2022/09/LoadSEER-case-study-PGE_2012.pdf

- ***for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …***
- ***information documenting the LoadSEER forecast's confidence levels, statistical accuracy of the individual variables and overall model, and so forth; and***
- ***the outputs from the LoadSEER forecast.***

In addition, the Department recommends that Xcel provide a comparison of the forecast provided in the IDP to actuals.

H. PLANNED NET LOAD (PNL) METHODOLOGY AND 15% DEPENDABILITY FACTOR

Notice Topic 16.E: Feedback, comments, and recommendations on the following areas of Xcel's IDP: Planned Net Load (PNL) methodology and 15% Dependability Factor

The Commission's Notice at point 16.E states that the comments on Xcel's "Planned Net Load (PNL) methodology and 15% Dependability Factor" are to be made at this time.

Xcel's Petition provides two key definitions:

- native loading—is the actual demand when all DER generation impacts are excluded;[172] and
- net loading—is the actual demand when all DER impacts are included.

Native loading assumes that Xcel cannot depend on any DER to lower peak demand; for example, due to the DER being non-dispatchable. Net loading is the demand actually seen at the substation for feeders and substation transformers with DER impacts included and assumes Xcel can rely upon all of the historical output.

According to Xcel the weakness of using net loading is that the amount of DER available is dependent on a variety of factors. For example, solar may not be available due to clouds. To address the uncertainty in DER availability Xcel developed the concept of PNL. PNL represents demand when a certain percentage of DER is assumed to be reducing native loading. For the initial development of PNL Xcel considered only community solar gardens (CSG) and rooftop solar.

Xcel's formula for calculating PNL is:

Equation 1. PNL

$$PNL = Native\ Loading - [(Native\ Loading - Net\ Loading) * 15\%]$$

Thus, PNL is equal to native loading reduced for DERs, but only after the DER impact has been reduced to 15 percent of actual impact. The 15 percent figure is referred to by Xcel as a "dependability factor"

[172] The native loading value is calculated via LoadSEER in the load forecast process.

of solar or DF_{PV}. The application of the DF_{PV} means PNL will always be between native loading and net loading.

The PNL results would be applied as follows:

> Currently, we check if the native load from the failed equipment can be transferred to neighboring sources by checking the restoring equipment sources' native loading in comparison to its rated capacity. We would apply the PNL methodology to our N-1 risk analysis by still utilizing the native loading on the failed equipment but instead, use the PNL for the equipment that restores service in comparison to its rated capacity. This is due to the fact that the DER generation will trip out of service when the failure occurs, but the DER generation on the restoring feeder will remain in-service.

The DF_{PV} was developed using five years of data (2016 to 2021), showing solar generation as a percentage of nameplate capacity rating from the Company's CSG program. This analysis is summarized in Table A1-11 of Appendix A1. Table A1-11 shows the following percentages (actual/nameplate):

- All day:
  - winter 5% to 11%;
  - spring 14% to 18%; and
  - summer 18% to 20%;
  - fall 8% to 15%.
- Tracking solar, hours 8:00 to 18:00:
  - winter 12% to 25%;
  - spring 30% to 36%; and
  - summer 37% to 40%;
  - fall 18% to 32%.
- Fixed solar, hours 10:00 to 16:00:
  - winter 16% to 33%;
  - spring 38% to 43%; and
  - summer 45% to 50%;
  - fall 23% to 40%.[173]

Using this data Xcel tested DF_{PV} of 15 percent and 25 percent. The key point is that Xcel's data shows that, at least on average, there is very little chance that less than 15 percent of nameplate solar capacity will be online during critical hours in any season during non-nighttime hours.

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[173] Less DER being on-line than expected is a problem because, if that occurs, the distribution network has to serve more capacity than expected.

The results of Xcel's tests are shown in Tables A1-12 to A1-15 of Appendix A1. When compared to use of native load, using PNL with a 15 percent DF_{PV} has a very small impact on the number of N-0 (system intact) and N-1 risks. Using PNL with a 25 percent DF_{PV} has a slightly larger impact on the number of N-0 and N-1 risks, but the impact is still small.

Based upon the analysis, the Company believes that data from existing solar indicates that a 15 percent DF_{PV} "would be the safest value to use and minimizes the likelihood that the actual DER impact on peak load could be less than 15 percent dependable in the future."

Xcel summarizes the proposal as follows. For the N-1 risk analysis, native loading would be used for the failed feeder and the restoring feeder would use PNL. In the initial implementation, PNL would begin with a DF_{PV} value of 15 percent.

For the N-0 risk analysis, Xcel is open to moving forward with a DF_{PV} value of 15 percent. However, Xcel states that "it is important for parties and the Commission to understand the drawbacks presented above – i.e., from a policy standpoint, the theoretical benefit of deferring a mitigation investment should be weighed carefully against the possibility of increased system risk and potential impacts to hosting capacity."

Overall, in the N-0 risk analysis, the application of a 15 percent DF_{PV} had minimal impact; only one risk was avoided. Avoiding only one risk using a 15 percent DF_{PV} means applying the PNL methodology to Xcel's N-0 risk analysis would have very little benefit in terms of avoided distribution upgrades. The application of a 25 percent DF_{PV} had a larger impact; seven risks were avoided. Still, the impact appears to be relatively small.

Based upon this data, the Department concludes that Xcel's PNL methodology and 15 percent DF_{PV} are reasonable. In addition, the Department recommends Xcel not implement the 15 percent DF_{PV} in the next planning cycle for N-0 risk analysis.

I. MODIFICATION OF IDP FILING REQUIREMENTS

Notice Topic 20: Should the Commission discontinue IDP Requirement 3.A.9 as requested by Xcel?

IDP Requirement 3.A.9 requires the following:

> For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system.

Xcel's Supervisory Control and Data Acquisition (SCADA) system "provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages."[174] Xcel notes that more than 95 percent of its customers are served by SCADA-enabled substations and feeders.[175] Therefore, Xcel is able to measure the maximum hourly coincident load (kW), as required by IDP Requirement 3.A.9, at substations serving 95 percent of its customers.[176]

Xcel notes the manual process required to generate the requisite data, as the maximum hourly load for each SCADA-enabled substation must be manually selected for the timing of the coincident peak load. In previous IDPs, Xcel completed this manual process but requested input from stakeholders regarding the value of the information provided and how Xcel may be able to provide the desired information in a more efficient manner. Xcel did not receive any feedback to this request, opted to forego the process to provide the information responsive to the requirement in its 2023 IDP, and again requests feedback regarding the value of the information requested. Absent such feedback, Xcel requests that the filing requirement be discontinued.

The Commission established four requirements for Xcel to provide information for filing requirements which "Xcel claims is not yet practicable or is currently cost-prohibitive to provide."[177] Xcel responds to each of the four requirements, but Xcel does not claim that the requirement is not yet practicable or cost-prohibitive to provide. Instead, Xcel describes the process to collect the information as "time and resource intensive" and estimates the process requires approximately four hours to complete.[178]

The Department does not believe four hours would reasonably be considered cost-prohibitive to provide. However, the Department appreciates that undertaking the manual process to provide information not utilized by stakeholders or the Commission does not benefit the regulatory process. The IDP filing requirements are extensive, and where opportunities exist to streamline or eliminate requirements that do not provide value, a review of such information is warranted. Accordingly, the Department is not opposed to the Commission discontinuing IDP Requirement 3.A.9 if stakeholders and the Commission are supportive.

The Department requests comments from stakeholders in reply comments regarding Xcel's proposal to discontinue IDP Requirement 3.A.9.

[174] IDP Appendix A4 at page 1.
[175] IDP Appendix A4 at page 2.
[176] IDP Appendix A4 at page 3.
[177] IDP Filing Requirements at page 1.
[178] IDP Appendix A4 at page 4.

J. THE INFLATION REDUCTION ACT AND UTILITY PLANNING AND BENEFITS

Notice Topic 23: Has Xcel Energy appropriately discussed its plans to maximize the benefits of the Inflation Reduction Act (IRA) and the IRA's impact on the utility's planning assumptions pursuant to Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G-999/CI-22- 624?

Order Point 1 of the Commission's September 12, 2023, Order in Docket No. E,G999/CI-22-624 states in part:

> The utilities shall maximize the benefits of the Inflation Reduction in […] integrated distribution plans […]. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.179

Xcel references the IRA briefly throughout the IDP, but the portions of the discussion that are reasonably considered responsive to the requirements established by the September 12, 2023, Order are limited to three sections of its IDP.

First, Xcel includes a discussion of the impacts of the IRA on its forecast in Appendix A1, System Planning.[180] Xcel indicates the incentives offered for EVs and solar have been incorporated into the forecasted adoption rates for each technology, increasing the expected adoption in 2030 by approximately 20 percent and 30 percent, respectively.[181] Xcel's discussion of the impacts of IRA on its forecast solely addresses EVs and solar adoption.

Second, Xcel includes a discussion of maximizing IRA benefits in Appendix D, Distribution Financial Information.[182] Xcel notes that the distribution system investments included in its budget would not be eligible for IRA tax credits, which are primarily targeted at energy generation, with the possible exception of its proposed hosting capacity upgrades if paired with renewable generation.[183] Xcel also discusses IRA tax credits for personal and commercial EVs and charging stations, and it reiterates the resulting impact on its EV forecast.[184]

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[179] *Order Setting Requirements Related to Inflation Reduction Act, In the Matter of a Joint Investigation into the Impacts of the Federal Inflation Reduction Act*, *Docket No. E,G999/CI-22-624* (September 12, 2023). *Hereinafter* September 12, 2023, Order.
[180] IDP Appendix A1 at page 47.
[181] *Ibid.*
[182] IDP Appendix D at page 4.
[183] *Ibid.*
[184] *Ibid*.

Third, Xcel describes how IRA tax credits are incorporated into the NWA Analysis in Appendix F.[185] Xcel notes that IRA tax credits for solar power purchase agreement costs have been included in its analysis, while tax credits for battery storage systems have not yet been incorporated.[186]

The Department notes the short time period from the September 12, 2023, Order to the filing of the IDP on November 1, 2023, and appreciates Xcel's efforts to incorporate the discussion of the IRA into its IDP. The Department acknowledges that future IDPs, as well as the other filings required to comply with Order Point 1, will likely become more comprehensive in response to the requirements.

Xcel notes that it is exploring how to incorporate other aspects of the IRA into future forecasts.[187] However, Xcel's reference appears to be limited to a discussion of EVs. The Department notes that IRA incentives address other forms of DER and electrification measures, as well, which are included in the requirements in the September 12, 2023, Order. Specifically, incentives for battery storage, heat pump air conditioner/heaters, heat pump water heaters, electric wiring and electric panel upgrades that facilitate electrification, among others, are relevant aspects of the IRA to include in a discussion of planning assumptions.

The Department requests that Xcel include in reply comments a description of how its distribution system planning will evolve with the incorporation of additional impacts from the IRA.

As Xcel notes in its IDP, commercial and industrial customers comprise approximately 77 percent of its electricity sales in its NSPM system.[188] Xcel also notes that its beneficial electrification forecasts for commercial and industrial customers are still under development,[189] which can be informed by a discussion of IRA impacts. The IRA also incentivizes domestic manufacturing across various industries, contributing to load growth across the country.[190] While the resulting investments appear limited in Minnesota at this time,[191] Xcel could incorporate these impacts into a broader discussion of the IRA and commercial and industrial customers in future filings.

The Department requests that Xcel provide in reply comments a discussion of the IRA impacts on planning assumptions regarding commercial and industrial customers.

[185] IDP Appendix F at page 46.
[186] *Ibid*.
[187] IDP Appendix A1 at page 48.
[188] IDP at page 12.
[189] IDP Appendix A1 at page 57.
[190] See, e.g., Wilson, J. D. & Zimmerman, Z., *The Era of Flat Power Demand is Over*, Grid Strategies. Available at: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.
[191] See Department of Energy, *Building America's Clean Energy Future*. Available at: https://www.energy.gov/invest.

K. ON THE TIMING AND SYNCHRONIZATION OF IDPS WITH OTHER PROCEEDINGS

Notice Topic 24: Other Areas of Xcel's IDP or TEP not Listed Above, Along With any Other Issues or Concerns Related to This Matter

The Department provides the following observation regarding timing of the IDP and integration with other processes such as rate cases and the Integrated Resource Plan. The IDP and the IRP are currently separate processes, but are not wholly unrelated. Currently all IDPs, including Xcel's IDP, are filed simultaneously on a schedule that is unrelated to other Commission proceedings. As such, there is no reason to assume that the inputs to Xcel's IDP analysis will be the same or similar to the inputs to Xcel's IRP—the difference in timing alone creates the potential for significant differences. In addition, due to the timing of Xcel's IDP, there is no reason to assume that the outputs from Xcel's IDP could be used as inputs to Xcel's IRP or any other proceeding. In essence, the current filing schedule leaves the IDP process as a standalone proceeding whose inputs and outputs are not easily integrated into any other Commission proceeding.

Finding an approach that integrates these processes and addresses the timing of these filings would be beneficial. For example, one approach would be to have Xcel's IRP and IDP filed on the same schedule so that they share a common set of inputs. Another approach would be to sequence the dockets so that the IDP is completed first and the IDP outputs can then be used as inputs to the IRP. The Department is interested in working with Xcel and other parties to address these concerns.

The Department requests feedback from Xcel and other parties on how to schedule the IDP filing to better integrate the IDP's inputs and outputs with other Commission processes in reply comments.

IV. RECOMMENDATIONS

Based on analysis of Xcel's IDP and the information in the record, the Department has prepared recommendations and a series of requests to be addressed during reply comments. Requests for additional information will provide a more robust discussion of information in the IDP. The Department will make final recommendations to the Commission after reviewing information received during replies and stakeholder input. Below, the Department provides its preliminary recommendations corresponding to the subheadings of Section III above and, separately, the requests for additional information.

PRELIMINARY RECOMMENDATIONS:

A. ***<u>IDP Compliance with Filing Requirements and Recommendations Concerning Acceptance</u>***

1. The Department recommends the Commission direct Xcel to refile Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects. Xcel should further be required to make any other necessary modifications to its IDP to reflect the necessary changes to Appendix C.

B. ***Xcel's Distribution Budget and Related Issues***

2. The Department recommends Xcel be required to separate the total "program" and "project" budgets into discrete programs and projects for all Budget Categories in Attachment H, Capital Project List by IDP Category, to the fullest extent possible.
3. The Department generally agrees that Xcel's proposed modifications to the IDP Filing Requirements to remove the IDP-specific categories for financial information are beneficial and provide consistency of budget categories across Xcel dockets. This proposal would also align with the Commission's directive in its July 17, 2023, Order. The Department supports the improved alignment of the IDP process with other dockets, including cost recovery proceedings. Furthermore, to facilitate a comparison of IDP filing requirements and budgets across all IDP filings, the Commission should implement these (or similar) revisions in upcoming procedures with other utilities.

C. ***Budgets and Cost Allocation for Distribution System Upgrades to Accommodate Distributed Energy Resources (DER)***

4. The Department recommends Xcel provide options, if any, to help distribute costs to interconnect a small residential facility on a saturated feeder including whether a flat interconnection fee, similar to the small solar array fee, has been considered for larger facilities.
5. The Department recommends the Commission adopt a new filing requirement to specifically address how beneficial electrification is anticipated to affect the distribution grid and cost allocation issues thereof.

D. ***Grid Modernization: Required Information and Cost-Benefit Analysis***

6. As stated in Section A, the Department recommends the Commission direct Xcel to refile Appendix C of its IDP to include all required information on grid modernization, including cost-benefit analyses of near-term projects. Xcel should further be required to make any other necessary modifications to its IDP to reflect the necessary changes to Appendix C.
7. The Department recommends the Commission clarify its requirement that Xcel comply with additional grid modernization filing requirements established by the Commission in Xcel's last rate case by providing a roadmap of planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs with its IDP.
8. The Department recommends that the Commission articulate the requirement that Xcel include a report of reliability performance for circuits equipped with FLISR, consistent with the Department's recommendations in the last general rate case.
9. The Department recommends that Xcel include in its IDP specific reliability goals, and to specify, and quantify to the extent practicable, other key objectives which its proposed investments support. To the extent possible, the Xcel should indicate the specific

contribution that individual proposed investments will make to achieve reliability improvements and other specific goals.

10. The Department recommends that Xcel refile its proposal for DI with a complete cost-benefit analysis demonstrating that DI is cost-effective. If the Xcel cannot demonstrate cost-effectiveness on narrow quantitative grounds, then it must provide justification for why it believes that the costs of DI should be allowed for recovery.

E. **Non-Wires Alternatives Analysis**

11. The Department recommends that Xcel provide consideration of NWAs for all non-asset-based distribution system projects.
12. The Department requests that Xcel reexamine the deferral period and payment structure as it develops NWA solicitations in future IDPs.
13. The Department recommends that Xcel modify its initial NWA analysis to account for the potential of incremental energy efficiency and demand response.
14. The Department recommends Xcel account for the potential long lead time NWA providers may face in developing the NWA solutions and not delay solicitation for bids from the marketplace.

F. ***Resiliency Performance Tracking and Microgrids***

15. The Department recommends that Xcel develop a suite of metrics to track resiliency, including SAIDI and SAIFI including MEDs, and other metrics to the extent warranted.
16. The Department recommends that Xcel further develop and clarify its resiliency metrics for the RMP to includes measures of system performance during major outage events.

G. ***Initial LoadSEER Forecasting Results and Methodology***

17. The Department recommends that, Xcel provide in the next IDP for one of the LoadSEER forecasts:
    - a complete list of the data sets used in making the LoadSEER forecast, including:
        - a brief description of each data set and
        - an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer);
    - a clear identification of any adjustments made to raw data to adapt them for use in the LoadSEER forecast, including:
        - the nature of the adjustment,
        - the reason for the adjustment, and
        - the magnitude of the adjustment;
    - a discussion of each essential assumption made in preparing the LoadSEER forecast, including:

    - the need for the assumption,
    - the nature of the assumption, and
    - the sensitivity of forecast results to variations in the essential assumptions;
- an equation showing the LoadSEER forecast model:
    - for example, Peak = a + b1 * Economic Variable + b2 * CDD/day …
- information documenting the LoadSEER forecast's confidence levels, statistical accuracy of the individual variables and overall model, and so forth; and
- the outputs from the LoadSEER forecast.

18. In addition, the Department recommends that Xcel provide a comparison of the forecast provided in the IDP to actuals.

H. ***Planned Net Load (PNL) Methodology and 15% Dependability Factor***

19. The Department recommends Xcel not implement the 15 percent DF_{PV} in the next planning cycle for N-0 risk analysis in the next IDP.

REQUESTS FOR ADDITIONAL INFORMATION DURING REPLY COMMENTS:

B. ***Xcel's Distribution Budget and Related Issues***

1. The Department recommends Xcel provide a discussion in Reply Comments regarding the underlying assumptions used to develop budgets in the IDP.

C. ***Xcel's Distribution Budget and Related Issues***

2. The Department recommends Xcel provide further information in reply comments as to whether the "Age-Related Replacements and Asset Renewal" budget also includes capacity expansion benefits.
3. The Department welcomes feedback from Xcel and other parties in reply comments as to whether discussion of alternative tariff structures belongs in an IDP.
4. The Department welcomes feedback from Xcel and other parties as to the feasibility of providing additional metrics to evaluate cost-effectiveness of capacity projects and which metrics would potentially be the most useful for evaluation.
5. The Department welcomes feedback from Xcel and other parties on the feasibility of implementing a cost allocation system for capacity upgrades.
6. The Department requests a discussion from Xcel in reply comments as to whether energy storage has been considered by Xcel to alleviate current or future solar DER capacity constrained feeders, and whether this subject warrants further investigation.
7. The Department recommends Xcel provide in reply comments information on how many projects can be supported with the proposed funding for hosting capacity upgrades and what level of DER those projects could enable, and how much forecasted DER increases this funding could address.

8. The Department requests Xcel discuss in reply comments the feasibility in future IDPs of conducting additional analysis of distribution system upgrade costs for additional types of DERs under various forecast scenarios.
9. The Department recommends Xcel and stakeholders provide feedback in reply comments on how forward-thinking Xcel should be when planning for the larger distribution grid it currently forecasts.

I. ***Modification of IDP Filing Requirements***

10. The Department requests comments from stakeholders in reply comments regarding Xcel's proposal to discontinue IDP Requirement 3.A.9.

J. ***The Inflation Reduction Act and Utility Planning and Benefits***

11. The Department requests that Xcel include in reply comments a description of how its distribution system planning will evolve with the incorporation of additional impacts from the IRA.
12. The Department requests that Xcel provide in reply comments a discussion of the IRA impacts on planning assumptions regarding commercial and industrial customers.

K. ***On the Timing and Synchronization of IDPs With Other Proceedings***

13. The Department requests feedback from Xcel and other parties on how to schedule the IDP filing to better integrate the IDP's inputs and outputs with other Commission processes in reply comments.

V. GLOSSARY

ADMS	Advanced Distribution Management System	**IRA**	Inflation Reduction Act
AMI	Advanced Metering Infrastructure	**IVVO**	Integrated Volt-Var Optimization
AMI-DI	Advanced Metering Infrastructure – Distributed Intelligence	**kW**	Kilowatt
ARR	Avoided Revenue Requirement	**MED**	Major Event Day
BESS	Battery Energy Storage System	**Minn.Stat.**	Minnesota Statute
BTM	Behind The Meter	**MPUC**	Minnesota Public Utilities Commission
CAIDI	Customer Average Interruption Duration Index	**MRP**	Multi-Year Rate Plan
CBA	Cost-Benefit Analysis	**MW**	Megawatt
CIP	Conservation Improvement Program	**MWh**	Megawatt-Hour
CSG	Community Solar Gardens	**NSPM**	Northern States Power Minnesota
DER	Distributed Energy Resources	**NSPM**	National Standard Practice Manual
DERMS	Distributed Energy Resource Management System	**NWA**	Non-Wires Alternative
DF_{PV}	Dependability Factor of Solar Photovoltaic	**O&M**	Operations and Maintenance
DI	Distributed Intelligence	**PNL**	Planned Net Load
DM	Demand Management	**PPA**	Purchase Power Agreement
DR	Demand Response	**PV**	Photovoltaic (solar)
DSM	Demand-Side Management	**RMP**	Resilient Minneapolis Program
ECO/CIP	Energy Conservation and Optimization/Conservation Improvement Program	**SAIDI**	System Average Interruption Duration Index
EE	Energy Efficiency	**SAIFI**	System Average Interruption Frequency Index
EV	Electric Vehicle	**SCADA**	Supervisory Control and Data Acquisition

FERC	Federal Energy Regulatory Commission	**TCR**	Transmission Cost Recovery
FLISR	Fault Location, Isolation, and Service Restoration	**TEP**	Transportation Electrification Plan
FTM	Front of The Meter	**TPS**	Technical Planning Standard
GRIP	Grid Resilience and Innovation Partnership (from the Bipartisan Infrastructure Law)	**V2G**	Vehicle to Grid
HAN	Home Area Network	**VPP**	Virtual Power Plants
IDP	Integrated Distribution Plan	**WACC**	Weighted Average Cost of Capital

VI. ATTACHMENT A: XCEL FILING REQUIREMENTS COMPLIANCE MATRIX

VII. ATTACHMENT B: XCEL PUBLIC RESPONSES TO DOC-IRs

VIII. ATTACHMENT C: XCEL TRADE-SECRET RESPONSES TO DOC-IRs

Compliance Matrix
Statutes

Statute	Requirement
Minn. Stat. § 216B.2425, subd. 2(e).	In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.
Minn. Stat. § 216B.2425, subd. 3.	Subd. 3.Commission approval. By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. The commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is: (1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers; (2) needed, applying the criteria in section 216B.243, subdivision 3; and (3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.
Minn. Stat. § 216B.2425, subd. 9.	The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023: 1) a forecast of distribution system upgrades necessary to accomodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects including energy storage systems; 2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and 3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
	Planning Objectives	The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to: 1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies; 2. Enable greater customer engagement, empowerment, and options for energy services; 3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and, 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs. 5. Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
		Commission review of ~~annual~~ distribution system plans ~~are~~ is[1] not meant to preclude flexibility for Xcel to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments. [1] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan and Modifying Filing Requirements (Nov. 2, 2020), Ordering Para. 4.*	N/A
		For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement: 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive; 2. How the information could be obtained, at what estimated cost, and timeframe; 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives; 4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.	Appendix A4: Distribution System Statistics
		Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: 1. An analysis of how the information presented in the IDP related to each Planning Objective, 2. The location in the IDP, 3. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and 4. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives[2] *2 In the Matter of Xcel Energy's 2018 Integrated Distribution Plan, Docket No. E-002/CI-18-251, Order Accepting Report, and Amending Requirements (July 16, 2019), Ordering Para. 5.*	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
1	Filing Date	Filing Date: Require Xcel to file annually with the Commission beginning on November 1, 2018, and biennially starting Nov 1, 2021[3] an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. Xcel must continue to file an annual update of baseline financial data and non-wires alternatives analysis.[4] The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776). [3] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (July 23, 2020), Ordering Para. 2.* [4] *July 23, 2020, Order (19-666) Ordering Para. 3*	This biennial IDP is being submitted November 1, 2023 in compliance with this requirement.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Stakeholder Meeting(s): Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	Appendix G: Stakeholder Engagement
3	Filing Requirements	Filing Requirements: For purposes of these requirements, DER is defined as "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."[5] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.[6] [5] *See Minnesota Staff Grid Modernization Report, March 2016.* [6] *See report on IDP prepared for the Commission by consultants ICF International, in In the Matter of the Commission Investigation into Grid Modernization, Docket No. E-999/CI-15-556, Notice of Integrated Distribution Planning Report and Stakeholder Workshop (September 13, 2016), eDockets ID: 20169-124836-01.*	Integrated Distribution Plan - Main Repot, VII.
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	Appendix A1: System Planning
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	Appendix A4: Distribution System Statistics
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	Appendix A4: Distribution System Statistics
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available	Appendix A4: Distribution System Statistics
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including a. Setting the forecasts for distributed energy resources consistently in its resource plan and its IDP b. Conducting advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours[7] [7] July 26, 2022, Order (21-694) Ordering Para. 4	Appendix A1: System Planning Appendix F: Non-Wires Alternatives Analysis
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	Appendix A1: System Planning

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018[8] impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018). [8] IEEE Standard 1547-2018 published April 6, 2018.	Appendix E: System Interconnection and Distributed Energy Resources
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	Appendix A4: Distribution System Statistics
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	Appendix A4: Distribution System Statistics
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	Appendix A4: Distribution System Statistics
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	Appendix A4: Distribution System Statistics
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	Appendix A4: Distribution System Statistics
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	Appendix A4: Distribution System Statistics
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	Appendix A4: Distribution System Statistics
3.A.15	Baseline Distribution System and Financial Data System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty)[9] [9] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting Filings and Establishing Requirements for Additional Filings (December 12, 2019), Ordering Para. 8.a.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations[10] b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program[11] c. Number and capacity of known public access direct current fast charging (DCFC) stations[12] d. Number and capacity of DCFC installed through a utility EV program, broken out by program[13] e. All other known EV charging stations (by type, ex DCFC, Level 2) [10] December 12, 2019 Order (17-879), Ordering Para. 8.e [11] December 12, 2019 Order (17-879), Ordering Para. 8.e [12] December 12, 2019 Order (17-879), Ordering Para. 8.f [13] December 12, 2019 Order (17-879), Ordering Para. 8.f	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.26	Baseline Distribution System and Financial Data System Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs[14] 1. Capital Costs 2. O&M Costs 3. Marketing & Communications 4. Other (provided explanation of what is in "other") The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization For each category, provide a description of what items and investments are included. [14] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (April 16, 2021), Ordering Para. 3.a.	Appendix D: Distribution Financial Framework and Information

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.A.27	Baseline Distribution System and Financial Data System Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.28	Baseline Distribution System and Financial Data System Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	Appendix D: Distribution Financial Framework and Information
3.A.29	Baseline Distribution System and Financial Data System Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs[15] 1. Capital Costs 2. O&M Costs 3. Marketing & Communications 4. Other (provided explanation of what is in "other") [15] April 16, 2021 Order (17-879), Ordering Para. 3.a	Appendix D: Distribution Financial Framework and Information Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend Attachment J: O&M Profile Trend
3.A.30	Baseline Distribution System and Financial Data System Data	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	Appendix A1: System Planning
3.A.31	Baseline Distribution System and Financial Data System Data	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers “high” DER penetration.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.A.34	Electric Vehicles	Electric Vehicles: A summary table with the following information for each EV rate offering or program during the reporting period: a) Number of customers and/or vehicles enrolled at the end of the reporting period b) Total energy consumed) MWh) during each EV tariff charging period c) Peak demand (MW) and the date and time at which occured[16] [16] December 12, 2019 Order (17-879), Ordering Para. 8b, 8c, and 8d	Appendix H: Transportation Electrification Plan
3.A.35	Electric Vehicles	Electric Vehicles: Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify)[17] [17] December 12, 2019 Order (17-879), Ordering Para. 8g; April 16, 2021 Order (17-879), Ordering Para. 3.b	Appendix H: Transportation Electrification Plan

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources[18], and any other method in which Xcel anticipates customer benefit stemming from the annual HCA. [18] Minn. Stat. 216B.2425, Subd. 8	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.[19] [19] In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Docket No. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018), establishing Minnesota's Distributed Energy Resources Interconnection Process (MN DIP) 3.2, "Initial Review."	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first. Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.[20] For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).[21] [20] July 23, 2020 Order (19-666), Ordering Para. 4 [21] December 12, 2019 Order (17-879), Ordering Para. 8h and 8i	Appendix A1: System Planning
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	Appendix A1: System Planning
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841[22] (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators) [22] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶61,127 (February 28, 2018)	Appendix E: Distributed Energy Resources. System Interconnection, and Hosting Capacity
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*[Merged into 3.D.2 per July 16, 2019 Order, Order Point 4] 18-251*	N/A

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Xcel shall provide a 5-year Action Plan as part of a 10-year long term plan[23] for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER future analysis, hosting capacity analysis[24], and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). 23 Modified by July 16, 2019, Order (18-251), Ordering Para. 4 24 Modified by July 16, 2019, Order (18-251), Ordering Para. 4	Appendix A1: System Planning, Appendix C: Action Plans Appendix D: Distribution Financial Framework and Information Attachment F: Planning Area Load Growth Assumptions, Attachment H: Capital Project List by IDP Category
		Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	See 3.D.2 Subparts below.
3.D.2.a	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Overview of investment plan: scope, timing, and cost recovery mechanism	Appendix C: Action Plans Appendix D: Distribution Financial Framework and Information
3.D.2.b	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[25] [25] See https://gridarchitecture.pnnl.gov/	Appendix B1: Grid Modernization
3.D.2.c	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	N/A - no investment proposal
3.D.2.d	Long-Term Distribution System Modernization and Infrastructure Investment Plan	System interoperability and communications strategy	Appendix B1: Grid Modernization
3.D.2.e	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	Appendix A1: System Planning
3.D.2.f	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Appendix C: Action Plans
3.D.2.g	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer anticipated benefit and cost	Attachment D: Distribution Risk Scoring Methodology Attachment E: Risk Scored Project Details Attachment G: Distribution Function NPV We note we are not requesting certification of any grid modernization investments.

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.D.2.h	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Appendix B2: Operational and Planning Data Management, Security, and Information Access Plans and Policies Appendix J: Distributed Intelligence
3.D.2.i	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Plans to manage rate or bill impacts, if any	Appendix C: Action Plans
3.D.2.j	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Attachment G: Distribution Function NPV
3.D.2.k	Long-Term Distribution System Modernization and Infrastructure Investment Plan	For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.[26] [26] *July 16, 2019, Order (18-251), Ordering Para. 3*	No new grid modernization projects in 5-year Action Plan. CBAs provided in Docket Nos. E999/M-15-962; E002/M-19-666; E002/M-21-184; E002/GR-21-630
3.D.2.l	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Status of any existing pilots or potential for new opportunities for grid mod pilots.	Appendix B3: Existing and Potential New Grid Modernization Pilots
3.D.2.m	Long-Term Distribution System Modernization and Infrastructure Investment Plan	The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.[27] [27] July 16, 2019, Order (18-251), Ordering Para. 9	Attachment D: Distribution Risk Scoring Methodology
3.D.2.n	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs[28] [28] July 16, 2019, Order (18-251), Ordering Para. 10	Attachment E: Risk Scored Project Details
3.D.2.o	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Long-range distribution studies conducted since the last IDP[29] [29] July 16, 2019, Order (18-251), Ordering Para. 11	N/A; addressed in Appendix A1: System Planning
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	Appendix C: Action Plans
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	Appendix F: Non-Wires Alternatives Analysis

Section	Heading	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694, based on Docket No. E002/CI-18-251)	Location
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b.A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed d. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	Appendix F: Non-Wires Alternatives Analysis
3.F.1	Transportation Electrification Plan	Xcel shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.[30] [30] December 12, 2019 Order (17-879), Ordering Para. 8j	Appendix H: Transportation Electrification Plan
3.F.2	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to facilitate:[31] a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory b. availability of residential charging options for both single family and multiple unit dwellings c. programs or tariffs in development to address flexible load or reduce metering and data costs; and d. fleet electrification. [31] December 12, 2019 Order (17-879), Ordering Para. 8k	Appendix H: Transportation Electrification Plan
3.F.3	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.[32] [32] December 12, 2019 Order (17-879), Ordering Para. 8m	Appendix H: Transportation Electrification Plan
3.F.4	Transportation Electrification Plan	Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.[33] [33] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Informational Requirements (May 17, 2022), Ordering Para. 4.	Appendix H: Transportation Electrification Plan
3.F.5	Transportation Electrification Plan	Xcel shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 20-745 at the conclusion of the pilot program.[34] [34] In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Programs as part of its COVID-19 Pandemic Economic Recovery Investments, Docket No. E-002/M-20-745, Order Approving Public Charging Station Proposal (April 27, 2022), Ordering Para. 8.	Appendix H: Transportation Electrification Plan
3.F.6	Transportation Electrification Plan	Xcel shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.[35] [35] In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (Apr 16, 2021), Ordering Para. 3.c.	Appendix H: Transportation Electrification Plan
3.F.7	Transportation Electrification Plan	Xcel shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.[36] [36] December 12, 2019 Order (17-879), Ordering Para. 8l	Appendix H: Transportation Electrification Plan
3.F.8	Transportation Electrification Plan	Xcel shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).[37] [37] December 12, 2019 Order (17-879), Ordering Para. 8n	Appendix H: Transportation Electrification Plan
3.F.9	Transportation Electrification Plan	Xcel shall provide citations with links to the most recent reports for any ongoing EV pilots or programs.[38] [38] December 12, 2019 Order (17-879), Ordering Para. 8o	Appendix H: Transportation Electrification Plan
3.F.10	Transportation Electrification Plan	Xcel shall provide historical spending for the past 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Appendix H: Transportation Electrification Plan
3.F.11	Transportation Electrification Plan	Xcel shall provide future spending for the next 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Appendix H: Transportation Electrification Plan

Order Point	MPUC IDP Requirement (8/7/18 Order in Docket No. E002/M-17-775 & E002/M-17-776)	Location
11	Xcel may file a Grid Modernization Report and certification request on November 1, 2018 in combination with an Integrated Distribution Plan in Docket No. E-002/CI-18-251. The filing should include for any certification request(s) at a minimum: (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.	N/A
Order Pt.	**MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)**	**Location**
6	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	Not applicable for 2023 IDP. See Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6.
7	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	Not applicable for 2023 IDP. No longer relevant - provided in Docket No. E002/M-19-666.
8	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	Not applicable for 2023 IDP. No longer relevant - provided in Docket No. E002/M-19-666.
Order Pt.	**MPUC IDP Requirement (7/23/20 Order in Docket No. E002/M-19-666)**	**Location**
5	Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.	Appendix G: Stakeholder Engagement
6	Xcel must engage stakeholders in further advancing the Company's NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.	Appendix G: Stakeholder Engagement
9	The Commission requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. **Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.**	Not applicable for 2023 IDP. Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020)

12	Xcel must produce a draft rate design "roadmap" with input from stakeholders and file it with the Commission by October 1, 2020. The Commission delegates authority to the Executive Secretary to set schedules and gather information on, or refer to the appropriate docket(s), the following: a. A summary of the Company's current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices. b. A timeline for proposing advanced rates and/or demand management programs for all customer classes. c. A discussion on what should be discussed in petitions for rate design changes, including: i. Whether program design strategies will be needed to support low income customer participation in these offerings, ii. Application to distributed energy resources and beneficial electrification, iii. Implementation plans, including education and outreach to customers, and	Not applicable for 2023 IDP. Filed 10/1/2020 in Docket No. E002/M-19-666
13	60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.	Not applicable to 2023 IDP. Filed 8/28/2020 in Docket No. E002/M-19-666
Order Pt.	**MPUC IDP Requirement (11/2/20 Order in Docket No. E002/M-19-666)**	**Location**
4	Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association's IDP filing requirements in the second paragraph under Planning Objectives are corrected as shown: Commission review of ~~annual~~ distribution system plans are is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.	See IDP Planning Objectives for Xcel Energy with the 12/8/22 Order.
Order Pt.	**MPUC IDP Requirement (7/26/22 Order in Docket No. E002/M-21-694)**	**Location**
2	Xcel shall file its smart inverter roadmap and related consultant reports in this docket by November 1, 2022	Submitted in Annual Update, Attachment E, submitted 11/1/2022 in Docket No. E002/M-21-694.
3	Xcel shall use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting.	Appendix F: Non-Wires Alternatives Analysis

5	Within 90 days, Xcel shall make a compliance filing that outlines key difference between its Colorado and Minnesota distribution system planning processes, including but not limited to a discussion of the following: a. Orders, rules, and statutes pertaining to distribution system planning b. How Xcel Energy conducts DER and load forecasting, including the Company's implementation of LoadSEER c. How Xcel Energy conducts its NWA analysis d. How Xcel Energy conducts its Hosting Capacity analysis	Compliance filing submitted 10/24/2022 in Docket No. E002/M-21-694.
6	Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans. This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings. The topics will include, but not be limited to the following: a. Integrated Distribution Planning 101 b. Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term. c. How energy efficiency, demand response, and other DER might impact Xcel's planning processes d. How Xcel should consider and incorporate local clean energy goals in its planning processes e. What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments	Appendix G: Stakeholder Engagement & Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694.

6 (Continued)	f. Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes g. Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions h. Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts i. How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast j. Estimate the potential synergies between interconnection upgrades sand planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system. Xcel shall make a compliance filing with the summary of the stakeholder process and a list of next steps by August 1, 2023. Xcel shall include a summary of the stakeholder series in its next IDP and relevant summary in its next IRP, including how it considered and incorporated stakeholder input.	Appendix G: Stakeholder Engagement & Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694.
7	The Commission certifies the Resilient Minneapolis Project and limits cost recover to a cost cap of $9 million unless Xcel can show by clear and convincing evidence that the costs were reasonable, prudent, and beyond the Company's control. Xcel shall file reports annually on December 1st through 2026. The first report is due on December 1, 2022 and must contain the following information: a. Define and quantify the emergency service capabilities and capacity in more detail and in more concrete terms than Xcel has hitherto provided in its proposal and via discovery responses. b. Report on the status of the emergency service capacity to ensure that the benefits are or can be realized, and to develop a process and a plan for demonstrating that the benefits can be realized. c. Define a process for identifying and addressing the potential situation in which either or both of the following conditions arise: the project fails to deliver all, or a large portion of Xcel's claimed quantified benefits and/or the claimed unquantified benefits cannot or are unlikely to materialize	Filed 12/1/22 in Docket No. E002/M-21-694.

8	Xcel shall consult with stakeholders, including RMP site partners, on the development of a set of evaluation metrics that allow comparison to other resilience offerings. This set of evaluation metrics shall be included in Xcel's December 1 annual reports. Xcel shall provide the following information and data to the greatest extent practicable. Where the Company is not able to do so, it shall explain why. Where applicable, Xcel must include data in spreadsheet (.xlsc) format. In consultation with stakeholders Xcel shall consider the following reporting elements when developing evaluation metrics:	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.a	Xcel shall include optional feedback from site hosts and community partners, using a form Xcel distributes on an annual (or more frequent) basis, which invites partners to discuss their experience participating in the project, its impact on the organization or community, or other information partners wish to share with the Commission.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.b	Xcel shall file a spreadsheet reporting, for each RMP site, the number of union labor jobs or contracts and the number of contracts awarded to women- and minority-owned businesses.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.c	Xcel shall file a spreadsheet reporting, for each RMP site, the number of workers trained in the operation of energy systems and the number of energy-related jobs created	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.d	Xcel shall record in a spreadsheet any instances of natural events or Company-orchestrated simulations in which RMP systems switch to "islanded mode" and how the system performs	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.e	Xcel shall track in a spreadsheet or in narrative form how RMP sites' rooftop solar, BESS, and microgrid are dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.f	Xcel shall report in a spreadsheet, for any of the RMP site, when a generator is used, for how long, and the generator power capacity and fuel source.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.g	Xcel shall quantify in a spreadsheet the number and type of HVAC upgrades, building envelope upgrades, energy efficiency measures, and/or demand response program undertaken at any of the RMP sites, shared at the discretion of RMP site hosts and partners	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
8.h	Xcel shall develop metrics related to resiliency benefits and energy equity and data collection on those topics	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694
9	Xcel shall file a letter in this docket to notify the Commission and stakeholders if the Company encounters any significant procurement challenges related to RMP, including delays, low bid numbers, or unexpected costs	See April 19 and June 9, 2023 filings in Docket No. E002/M-21-694.

10	Xcel shall include a discussion of the RMP in comparison to battery and microgrid programs/projects in Xcel's service territories in other states, lessons learned form these programs as they move through construction and into operation, and specific details how these lessons are informing RMP project decisions, reducing costs, and/or improving efficacy a. Xcel shall include this information in Xcel's 2023 IDP filing b. Xcel shall include this information in each of Xcel's annual reports filed in Docket No. E-002/M-21-694	Appendix B3: Existing and Potential New Grid Modernization Pilots
11	Xcel shall report on the Resilient Minneapolis Project in its quarterly reports in Docket No. E,G-999/M-20-492	See Docket No. E,G999/M-20-492
Order Pt.	**MPUC IDP Requirement** **(12/8/22 Order in Docket No. E002/M-21-694)**	**Location**
3	Allows utilities to file EV data in future IDP Plans that align with the data filed in their Annual Program Electric Vehicle reports (due June 1 of each year)	Appendix H: Transportation Electrification Plan
Order Pt.	**MPUC IRP Requirement** **(4/15/22 Order in Docket No. E002/RP-19-368)**	**Location**
9	Xcel shall takes steps to better align distribution and resouce planning, including: A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan. B. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. C. Proactively plan investments in hosting capacity and other necessary system capactiy to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources. D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs. E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	See corresponding IDP Requirement 3.A.5. Appendix A1: System Planning Appendix F: Non-Wires Alternatives Analysis
Page #	**Docket No. 16-521, Staff Briefing Papers for the May 20, 2021 Commission Meeting**	**Location**
22	Already, the Commission has seen crossover with the DGWG and IDPs, hosting capacity analysis, grid modernization investments, and more. As mentioned, the rate-regulated utilities will discuss anticipated impacts of the FERC Orders in their IDPs to be filed November 1, 2021. Staff anticipates more robust discussion of these issues in the 2021 IDPs.	Appendix E: System Interconnection and Distributed Energy Resources
Order Pt.	**MN Electric Rate Case Requirements** **(Order 7/23/23 in Docket No. 21-630)**	**Location**
27.b	Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR’s reliability results in its Integrated Distribution System Plan.	Appendix B1: Grid Modernization Appendix D: Distribution Financial Information

29	In its next Integrated Distribution Plan, Xcel must propose and discuss ways for the IDP Process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP	Executive Summary
31	Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.	Appendix D: Distribution Financial Information
33	The Commission rejects Xcel's proposal for the Distributed Intelligence program without the prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement	Appendix J: Distributed Intelligence
36	Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.	Appendix B1: Grid Modernization
133	Xcel shall, in its next Integrated Distribution plan ("IDP), quantify the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments	Appendix C: Action Plans
Order Pt.	**TCR (Order 6/28/23 in Docket No. 21-814)**	**Location**
17	Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing: a. HAN, AMI, and AMI-DI specifications and related customer data access policies. b. Bring-your-own device HAN requirements and terms c. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN. d. Methods to provide customers equal access to the level of data available to the utility. e. A summary of industry customer data access standards	Appendix J: Distributed Intelligence
Order Pt.	**IRA (Order 9/12/23 in Docket No. CI-22-624)**	**Location**
1	The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how […] the Act has impacted planning assumptions including (but not limited to) […] the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.	Appendix D: Distribution Financial Information

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Xcel Energy		Information Request No.	11
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, p. 33; Appendix B1

In Excel with supporting workpapers, please provide the number of feeders where FLISR has been deployed by year. Please indicate which feeders have multiple FLISR installations.

Response:
Please see Attachment A for the list of feeders and the number of automated devices that have been installed as part of the FLISR project and the number of automated devices that are complete with all of the activities to be enabled in ADMS.

Attachment A is marked "Non-Public" as it contains confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(a). Due to security information policies and concerns, the information provided in this response has been marked Non-Public. The public disclosure or use of this information creates an unacceptable risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. Thus, Xcel Energy maintains this information as trade secret pursuant to Minn. Rule 7829.0500.

Preparer:	Chad Nickell
Title:	Sr Director Grid Transformation
Department:	Sys Planning and Strat
Telephone:	303-571-3502
Date:	February 15, 2024

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Xcel Energy		Information Request No.	12
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, Appendix B1; Order in GR-21-630

Please explain why Xcel has not provided "reliability performance for circuits equipped with FLISR" per Order number 25 in the Commission July 17, 2023, Order in GR-21-630. If Xcel has presented these results, please provide a reference and the analysis with supporting workpapers in Excel spreadsheets with all formulas intact.

Response:
The Commission Order does not require the Company to report this information in the Integrated Distribution Plan. We believe the best place to provide this information is with our electric reliability performance results in the Service Quality docket. We will respond to Order Point 25 in our Service Quality filing due on April 1, 2024.

Preparer:	Bridget Dockter
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Telephone:	612-337-2096
Date:	February 15, 2024

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Xcel Energy		Information Request No.	13
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, Appendix B1; Order in GR-21-630

Please provide a page reference in the IDP where Xcel has presented "FLISR's reliability results" per Order number 27b in the Commission July 17, 2023, Order in GR-21-630. If Xcel has not presented reliability results, please explain why not.

Response:
The Company has provided a narrative summary of FLISR's reliability results in Appendix B1, pages 20 through 22.

Also, please see the Company's response to DOC Information Request No. 14.

Preparer:	Chad Nickell
Title:	Senior Director, Grid Transformation
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Telephone:	303-571-3502
Date:	February 15, 2024

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Xcel Energy		Information Request No.	14
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, Appendix B1

Please provide the annual reliability performance for circuits where Xcel has installed FLISR installed in Excel spreadsheets with all formulas intact. This should include the following with all supporting workpapers and calculations in Excel:

a. Feeder ID
b. SAIDI for each of the five years prior to FLISR installation, excluding major weather events
c. SAIFI for each of the five years prior to FLISR installation, excluding major weather events
d. Annual SAIDI and SAIFI, excluding major weather events, for all years including and after FLISR is installed (please indicate which year FLISR is installed on each feeder)
e. An explanation for each feeder of why Xcel believes reliability was better or worse after FLISR was installed

Response:
The questions reference circuits or feeders that the Company "has installed FLISR" on. As discussed in Appendix B1: Grid Modernization of this IDP and described in more detail below, FLISR is not "installed on feeders" rather it is an integrated technology that consists of 1) an advanced application in ADMS, 2) two-way communication, and 3) automated field and substation (reclosers, switches, substation relays) equipment.

At a high level, the implementation of FLISR includes the deployment of automated field devices, upgrades and changes to substation relays, integration with ADMS, and finally, the use of FLISR by the Distribution Control Center (DCC). As devices are installed, we go through a process to commission or integrate the devices with ADMS, which includes enabling the two-way communication to the device and a

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process to add the device and communication settings to ADMS prior to final commissioning in ADMS. Once a feeder has all its devices available in ADMS, we undergo a final testing to release the use of FLISR to the DCC.

We also know that the use of FLISR technology is new to the Company and will require additional management, training, and experience for the Company's employees to become proficient in the use of the technology. As discussed in Appendix B1of this IDP on the bottom of page 21 and the top of page 22, there are different phases of FLISR. As the Company progresses from the installation of automated devices on feeders, the technology will become available in ADMS for use by the DCC, until eventually fully automated control within ADMS is achievable.

While this work is focused on specific feeders, it should not be expected that either a feeder has "FLISR" or it does not, because, as previously described, it requires multiple phases to enable fully automated control within ADMS.
As it relates to the reliability benefits of FLISR and parts b through e of the information request, FLISR provides reliability benefits to feeder level outages (not outages at all levels) and one of the Company's criteria is to target parts of the distribution grid that have had a higher number of feeder level outages. The Company understands the questions to be asking for a comparison of reliability at all levels (emphasis on all levels) before the Company started the FLISR project and after the Company has completed at least one of the phases of implementing the FLISR technology on an individual feeder. The Company believes there is limited value for such a comparison, as reliability is a combination of many factors and variables – comparing reliability at all levels and trying to attribute reliability to a single factor like FLISR is unlikely to draw any meaningful conclusions, especially given the Company is currently in the early stages of the FLISR deployment.

Attachment A is marked "Non-Public" as it contains confidential security data that the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(a). This is information that the Company believes could be manipulated to reveal the location and size of facilities serving our customers. The public disclosure or use of this information creates a risk because those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the public version of our filing.

a. See Attachment A.
b. See Attachment A.
c. See Attachment A.
d. The Company started the FLISR project in 2021 and will continue expanding the field device rollout through 2027. Please see DOC IR No. 11 Attachment A TRADE SECRET/PUBLIC for a list of feeders that have automated field

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devices installed as part of the FLISR project. The Company began enabling automated field devices that have been installed as part of the FLISR project in ADMS beginning in 2023, and functionality will continue to be expanded through 2027, as we follow our installation schedule for automated devices.

For annual SAIDI and SAIFI for all years, see Attachment A.

e. See the response above. While we have not started to quantify the actual reliability benefits for each individual feeder, we can broadly say that we expect FLISR to improve customers' reliability experience by reducing the duration of outages and number of customers affected by them.

Additionally, FLISR devices will provide more robust data that engineers will use to help focus our investments. For example, we will have better insights into transient and momentary faults on the distribution system that cause momentary outages, which helps us focus resources to address the causes more specifically. Rather than patrolling a feeder looking for a cause, we will be able to identify the location of the issue before going to visit in the field.

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Telephone:	303-571-3502
Date:	February 15, 2024

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Xcel Energy		Information Request No.	15
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, Appendix B1, Table B1-11, p. 20.

a. Please separately explain and define what "actual additions" and "latest forecasted additions budget" are.
b. Please add a row to the referenced table that provides the annual amount of expenditure actually incurred for FLISR deployment in each year 2022 and 2023. If this is already provided, please indicate which row this is.
c. Please add a row that indicates the number of feeders and FLISR installations that were proposed in Xcel's previous rate case for each year shown.
d. Please add a row that indicates the number of feeders and FLISR installations actually installed in 2022 and 2023, respectively.
e. Please explain whether Xcel intends to spend the full authorized amount shown for 2022-2024. If not, will Xcel refund the balance?
f. Please explain whether the forecast shown in the table has been approved by the Commission. If not, will Xcel install FLISR per its forecast without explicitly asking for Commission approval? Please explain and indicate where and when Xcel intends to request approval of forecast funding.

Response:
a. The actual capital additions and latest forecasted additions budget are from the Company's July 2023 financial update.
b. Please see the following Table B1-11 from Appendix B1 with an additional row providing actual FLISR expenditures for 2022 and 2023.

**Table B1 - 11: Approved FLISR Additions Budget
Minnesota Electric (Millions)**

	MYRP Period			Forecast			
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Approved FLISR Additions Budget	$3.4	$7.8	$7.8	$8.2	$20.0	15.3	-
Actual Additions	$0.1	$1.2*	-	-	-	-	-
Actual Expenditures	$0.7	$4.6**	-	-	-	-	-
Latest Forecasted Additions Budget	$0.1	$5.2	$11.0	$13.0	$15.5	$15.5	-

**Actual additions through June 2023.*
***Actual expenditures through December 31, 2023.*

c. Please see the Company's response to DOC Information Request 14. The Company does not "install FLISR". The Company's cost benefit analysis included the estimated number of automated device installations by year which were 41 in 2022, 108 in 2023, and 107 in 2024.

d. Please see the Company's response to DOC Information Request 14. The Company does not "install FLISR". The Company provided the number of device installations by year in DOC Information Request 11.

e-f) The Commission approved the Company's cost recovery request for FLISR in the 2022-2024 MYRP (Docket No. E002/GR-21-630), and a component of the 2022-2024 MYRP was a requirement to file an annual capital true-up compliance report. The capital true-up is a one-way mechanism that requires customer refunds when actual capital-related revenue requirements are less than the capital-related revenue requirement amounts approved in the applicable year of the multiyear rate plan (MYRP) rate case. Based on this requirement, if the authorized level of revenue requirement for the applicable year is not incurred, a refund will be issued to customers as was the case in our 2022 Capital True-Up Compliance Report filed on November 3, 2023.

Preparer: Chad Nickell
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Department: Sys Planning and Strat
Telephone: 303-571-3502
Date: February 15, 2024

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Xcel Energy		Information Request No.	16
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: FLISR
Reference(s): IDP, Appendix B1, Tables B1-9, B1-10, and B1-11,

a. For 2024-2027, please explain the difference between the forecasted amounts in Tables B1-9 and B1-10 versus B1-11.
b. Please explain and provide the distinction between a "capital expenditure" and "capital addition."

Response:
a) Tables B1-9, B1-10, B1-11 represent capital expenditures, O&M expenditures, and capital additions, respectively.
b) Capital expenditures represent when the actual expenditure occurs in a specific year. Capital additions represent when capital expenditures are placed into service.

Preparer:	Chad Nickell
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Department:	Sys Planning and Strat
Telephone:	303-571-3502
Date:	February 15, 2024

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Xcel Energy		Information Request No.	17
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

<u>Question:</u>
Topic: FLISR and wildfire risk
Reference(s): IDP, Appendix B1

a. Has Xcel considered the interaction of FLISR technology with the risk of a utility-caused ignition? Please explain.
b. Does Xcel plan on installing FLISR on feeders with high wildfire risk (for example, on rural feeders near vegetation)? Please explain and provide any supporting analyses Xcel has accomplished on these issues.
c. Please explain whether adjusting FLISR settings to account for wildfire risk, for example by not allowing reclosers to operate during periods of wildfire risk, will diminish the reliability benefits of FLISR.
    a. Has Xcel considered this in its deployment of FLISR? How?
    b. Please provide all supporting analyses conducted by or known by Xcel related to this topic, including by Xcel Colorado.

<u>Response:</u>
a. Yes, however, not in Minnesota because the risk of wildfire in Minnesota according to the FEMA national risk index (on February 14, 2024) does not have any relatively high or very high wildfire risk. Should the risk warrant it in the future, the Company would incorporate these factors into where and how FLISR schemes may operate.
b. No. see Response to Question A.
c. See Response to Question A.

Preparer:	Craig Holt
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Telephone:	303-571-3477
Date:	February 15, 2024

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Xcel Energy		Information Request No.	18
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

<u>Question:</u>
Topic: Distributed Intelligence (DI)
Reference(s): IDP, Appendix J, p. 3.

a. Please explain why Xcel is "not seeking approval of our DI plans at this time," but is "moving forward with certain DI use cases" for which Xcel "intend(s) to seek cost recovery in a future cost recovery proceeding."
b. In Xcel's view, have the concerns that were raised about the Company's DI proposal in its last general rate case been addressed by the Company through modifications to its DI planning? Please explain in detail.
c. Is Xcel's DI program cost effective? Please explain in detail.
d. Please provide all benefit-cost analyses conducted by Xcel related to use cases it intends to move forward with in the near future. Please provide these benefit-cost analyses in Excel with all supporting workpapers and an explanation of the analysis.
e. Please provide the estimated amount of costs, by year if available, that Xcel is "moving forward" with. In the response, please indicate the percentage of these costs that are capital vs. expense.

<u>Response:</u>
a. The Company will seek approval for program costs in a Demand Side Management (DSM) plan modification and approval for all other costs in a future rate case.
b. Yes, the concerns that were raised about the Company's DI proposal in its last general rate case have been addressed by the Company through modifications to our DI planning. The specific terms of the unanimous Settlement Agreement (hereafter "the Colorado DI Settlement" or "the Settlement"), which is referenced in the Commission's Order, affect our DI plans in Minnesota and are discussed on page 25 of Appendix J. We have implemented several modifications to our DI planning. First, program costs have been separated from capital costs and now the cost of running the program is being evaluated as a behavioral savings program. Second, we have shifted the

Distributed Intelligence portfolios away from a NSPM-owned shared asset model, to a common asset model which ensures equitable distribution of costs amongst all territories. Third, development is focused on Release 1 and Release 2 of My Energy Connection[1] which allows for presentation of a more detailed development roadmap.

c. The customer facing DI program run costs will be evaluated in our forthcoming DSM plan modification using the societal test, and capital costs will be evaluated in future rate case proposal.

d. We are not seeking certification in this proceeding. We will submit the cost benefit analysis (CBA) in future cost recovery proceedings.

e. Program run costs estimates will be provided in our forthcoming DSM plan modification. Capital cost estimates will be provided in a future rate case.

Preparer:	Dora Irvine
Title:	Product Portfolio Manager
Department:	Product Strategy and Development
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Date:	February 15, 2024

[1] My Energy Connection and My Energy Portal are two separate products. My Energy Connection is not a portal, it is an application that lets customers view their real-time energy usage. My Energy Portal allows customers to see their 15-minute historical data.

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Xcel Energy		Information Request No.	19
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Distributed Intelligence (DI)
Reference(s): IDP, Appendix J, p. 3.

Does Xcel intend to seek cost recovery for DI in its next rate case, or will it seek cost recovery through a different cost recovery mechanism? Please explain in detail.

Response:
Please see our response to DOC Information Request No. 18.

Preparer:	Amber Hedlund
Title:	Manager, Regulatory Project Management
Department:	NSP Regulatory
Telephone:	612-337-2268
Date:	February 15, 2024

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Xcel Energy		Information Request No.	20
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Distributed Intelligence (DI)
Reference(s): IDP, Appendix J, p. 3.

Please explain what the clearance requirements are for vegetation relevant to that shown in the figure, and whether Xcel was fined for this instance of not meeting the requirement.

Response:
We believe the figure in question is Figure J-1 on page 5 of Appendix J and provide a response regarding that figure. There are not any mandatory clearance requirements for distribution voltages in Minnesota. The Company has a vegetation management program to support our safety and reliability goals and objectives by controlling growth and removal of encroaching vegetation near electrical lines and other critical infrastructure, while remaining in compliance with federal, state, and local laws and ordinances.

Our clearance guidelines are based on tree growth rates and structural defects in the tree, as well as the type of power line, voltage, outage history, and other factors. When possible and practical, contract tree workers are expected to adhere to the American National Standard Institute's (ANSI) A-300 standards for the care and maintenance of trees, shrubs, and other woody plants. This standard is intended as a guide for federal, state, municipal, and private authorities, including property owners, property managers, and utilities.

Preparer:	Fletcher Johnson
Title:	Director, Vegetation Management & Pole Integrity
Department:	Vegetation Management
Telephone:	651-229-2485
Date:	February 15, 2024

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Xcel Energy		Information Request No.	21
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Distributed Intelligence (DI)
Reference(s): IDP, Appendix J, Figure J-1, p. 5.

a) Regarding "EV detection" will DI technology allow Xcel to submeter EVs and charge separate rates (e.g. an EV-only rate)? Please explain.
b) Please explain whether DI provides Xcel a connection to customers and potential marketing opportunities as well as "brand awareness."

Response:
a. No, the EV Detection application is not expected to have meter level accuracy to support EV sub-metering and separate rates.
b. No. Distributed Intelligence (DI) does not provide a connection to customers for marketing or brand awareness purposes. The Company, however, intends to use DI capabilities to help customers better manage their energy usage.

Preparer:	Chad Nickell
Title:	Senior Director, Grid
Department:	System Planning & Strategy
Telephone:	303-571-3502
Date:	February 15, 2024

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Xcel Energy		Information Request No.	22
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Energy Efficiency and Demand Response in Load Forecasting
Reference(s): IDP, p. 2; Appendix A1, p. 41

Please provide the specific projections for energy savings and peak load reductions associated with Energy Efficiency and Demand Response, per year, that are assumed in Xcel's load forecast.

Response:
Attachment A contains the annual energy savings and peak load reductions associated with Energy Efficiency and Demand Response assumed in the Company's load forecast.

Preparer	Benjamin Levine
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Department:	Load Forecasting and Analysis
Telephone:	651-558-1923
Date:	February 15, 2024

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Xcel Energy		Information Request No.	23
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Rate Design and Load Forecasting
Reference(s): IDP, p. 3; Appendix A1

a. What assumptions does the Company make in its load forecast about customer enrollment in TOU rates and the impact of these rates on peak load growth? Please explain in detail.
b. Please provide any other assumptions that the Company makes about the impact of rate design on the growth of system peak in its load forecast.

Response:
a. The Company does not make adjustments to its forecast results for the impact of additional customer enrollment in TOU rates.
b. The Company's forecast is based on existing rate design. To the extent there are current programs or rates that impact peak demands, those are picked up in the forecast results. The Company does not make adjustments for changes in rate design when developing its load forecast.

Preparer:	Travis A. Whalen
Title:	Manager, Energy Forecasting
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Date:	February 15, 2024

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Xcel Energy		Information Request No. 24
Docket No.:	E002/M-23-452	
Response To:	Minnesota Department of Commerce	
Requestor:	Peter Teigland, Daniel Tikk	
Date Received:	February 5, 2024	

Question:
Topic: Load Forecasting
Reference(s): IDP, Figure 1, p. 3

a. Do each of the IDP scenarios presented in Figure 1 assume achievement of state policy mandates? If not, please explain in detail why not.
b. Does the capital budget provided in this IDP (and the specific investments contemplated in this budget) correspond to any of these IDP scenarios in particular? Please explain in detail.

Response:

a. We are assuming for purposes of this response that state policy mandates refers to the new three percent Distributed Solar Energy Standard (DSES) and the new Community Solar Garden legislation established in the 2023 Minnesota legislative session. All three IDP scenarios account for the three percent DSES. Additionally, the Distributed Energy Resource (DER) Front of the Meter (FTM) Solar PV Forecast in the IDP High scenario assumes that the interconnection of community solar gardens will reach its annual cap (as outlined in the legislation) every year of the forecast. See pages 64 and 65 of Appendix A1 System Planning for more information. Please also see the Company's response to IR 28.
b. The capital budget provided in this IDP corresponds to the scenario called "Budget Plan." See pages 49 and 50 of Appendix A1 System Planning for more information. This "Budget Plan" scenario is a forecast of traditional load growth on the distribution system and does not include the impact of the scenario forecasted DER adoption. With the exception of the "Proactive Upgrades for Hosting Capacity" item, the capital budget provided in this IDP similarly only corresponds to meeting the needs of traditional load growth on the distribution system, not DER adoption. The "Proactive Upgrades for Hosting Capacity" item in the capital budget is intended to provide a high-level start to indicate costs that may be required to accommodate DER adoption but does not correspond to any of the DER forecast scenarios presented in this IDP.

Preparer:	Meghan Tisdell
Title:	Sr Engineer
Department:	NSP Distribution Planning
Telephone:	763-493-1850
Date:	February 15, 2024

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Xcel Energy		Information Request No.	25
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Reliability
Reference(s): IDP, p. 4; Appendix A2, p. 12; Appendix D, p. 7

Is Xcel targeting reliability improvement through the capital plan included in this IDP? If so, please provide any specific targets for reliability improvement.

Response:
As discussed throughout the IDP, we make both proactive and reactive reliability improvement investments on an annual basis and have a robust process to evaluate and rank what those priority areas are. The Company does not have specific quantitative reliability improvement targets associated with the capital plan included in this IDP. Our goal is to continue to maintain the excellent level of safe and reliable service our customers have come to expect from the Company.

Preparer:	Michael Renman
Title:	Manager
Department:	Electric System Performance
Telephone:	651-229-2509
Date:	February 15, 2024

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Xcel Energy		Information Request No.	26
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Resiliency
Reference(s): IDP, p. 4

a. Does Xcel have specific plans to measure improvements in resiliency? If so, please explain how resiliency improvements will be measured?
b. Does Xcel have specific resiliency objectives? If so, please provide these objectives.

Response:
a. The Company defines resilience for the distribution system as focusing on the system's ability to withstand, endure, and recover from significant events that can create widespread outages and result in long-duration restoration times. SAIDI and SAIFI are directionally corelated to resiliency, and as such, over the long term, they give an indication of resiliency. In addition, our annual targets and measures are generally based off a normalized data set, which excludes major events, as defined by IEEE standard 1366.
b. The Company aims to maintain and bolster resiliency on our system by investing in projects that allow us to maintain reliable service for our customers and to harden our system against extreme weather events, as appropriate. Our budget framework incorporates not only the necessary work to maintain poles and wires, but also the work needed to prepare for the future, facilitate the clean energy transition, maintain and enhance reliability and resilience, and modernize our customers' interaction with the distribution grid. To this end, the Company has several programs and initiatives, such as replacing remaining porcelain cutouts on our system with polymer, transitioning our crossarms from wood to fiberglass, investments in outage detection and restoration technologies, and modernizing our grid. More details can be found in the appendices listed in Table 1: Location of Topics of the First Planning Objective in the IDP in Attachment C: IDP Content to MPUC Objectives.

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Date:	February 15, 2024

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Xcel Energy		Information Request No.	27
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Resiliency
Reference(s): IDP, p. 4

a. Please provide references to all relevant Minnesota policy and statutory mandates and any prior directives from the Commission related to resiliency.
b. Please explain how each of the relevant policy and statutory mandates related to resiliency cited in response to (a) are reflected in the proposals and plans included in the instant IDP.

Response:
a. The Company is unaware of any Minnesota statutory mandates related explicitly to resiliency that impact Xcel Energy or other utilities. In regards to resiliency, in the IDP, the Commission's Planning Objectives state that:

The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:
1. *Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;*

b. In Attachment C: IDP Content to MPUC Objectives, we follow the format the Department used in their February 22, 2019, Comments in Docket No. E002/CI-18-251 in complying with the Commission's requirement that the Company include the following in the IDP:

1. *An analysis of how the information presented in the IDP related to each Planning Objective,*
2. *The location in the IDP,*
3. *Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and*
4. *Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.*

We refer the Department to Table 1: Location of Topics of the First Planning Objectives in the IDP for where the Commission's Planning Objectives – including resiliency – are discussed in the IDP.

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Xcel Energy		Information Request No.	28
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Legislative Action
Reference(s): IDP, Table 1, p. 9

Please explain how each of the statutory developments noted in Table 1 are reflected in the proposals and plans included in the instant IDP, and to the extent possible, please cite to specific contents within this IDP that are reflective of these developments.

Response:
Table 1 below provides the locations of where statutory developments are discussed in the 2023 IDP. We would like to note that while these are specific places these statutes are discussed, the entirety of the IDP is intended to respond to these statues and Commission Orders by describing how the Company plans, maintains, and improves our distribution system to safely and reliably serve our customers. As such, reading only these sections may not give a wholistic picture of the Company's plans or statutory implications.

Table 1
Statutes and Relevancy to the 2023 IDP

Statute	Description and Relevant Docket	In IDP Proposals and Plans
216B.1641	Community Solar Garden (CSG) program modifications Docket No. E002/M-23-335	In *Appendix A1: System Planning*, we describe how the Bass Diffusion model was used in determining the Medium and Low scenarios for the CSG forecasts. The high case matches the annual cap for CSGs established in the legislation (100 MW/year, then 80 MW/year, then 60 MW/year). We discuss more specifics in *Appendix I: Distribution System Upgrades*. To create the required forecast of distribution system upgrades, we used the location-specific LoadSEER forecast data discussed in *Appendix*

		A1: System Planning. Specifically, we used the allocation data from the IDP High scenario of the solar PV adoption forecast. The IDP High scenario for solar PV comprises two component forecasts: behind the meter (BTM), and front of the meter (FTM). The BTM forecast component includes rooftop solar, and the FTM component includes both CSG solar and DSES solar. In the "IDP High" scenario, the FTM forecast includes the estimated 500 MW of solar required to meet the DSES spread over 2026-2029, and also assumes that CSG adoption will reach the annual cap specified in Minn. Stat. § 216B.1641. The total amount of solar allocated to the distribution system for both BTM and FTM solar in the 30-year forecast for this analysis is shown in Figure I-1.
216C.378	Distributed Energy Resources System Upgrade Program Docket No. E002/M-23-458	As discussed in Section I.D.3. of *Appendix A1: System Planning,* for the first time in our five-year budget (*Appendix D: Distribution Financial Framework and Information*) we included funds for significant investments in proactive hosting capacity upgrades in 2025 through 2028. Specifically, we included $190 million for system upgrades to increase hosting capacity, which would enable more DER interconnection and increased load. We noted that the program is not yet fully scoped and should be considered a placeholder at this time. We are interested in hearing from stakeholders and the Commission on how we should approach proactive investments in hosting capacity, including how we should potentially prioritize such investments over others. In addition, we also filed our Distribution System Upgrade Plan with the Minnesota Department of Commerce, pursuant to Minn. Stat. § 216C.378 as added by Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F. No. 2310).
216C.379	Energy Storage Incentive Program Docket No. E002/M-23-459	In *Appendix B3: Existing and Potential New Grid Modernization Pilots,* we discussed our proposal for a program in line with the statute. The program will be designed to provide a one-tine grant of up to $5,000 for solar PV systems with a connected battery of up to 50 kWh. Our proposal for this program was filed on November 1, 2023, in Docket No. 23-459. Additionally, we are developing a demand response program in parallel that will build on the Renewable Battery Connect Program offered in CO. We intend to propose this as part of our 2024-2926 Energy Conservation and Optimization (ECO) Triennial via a modification sometime in 2024.

		There is additional information about energy storage and its potential benefits in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity* and *Appendix B1: Grid Modernization.*
H.F. 2310 Article 12, Section 75	Queue priority for DER up to 40 kW Docket No. E999/CI-16-521	In Section V.D. of *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity* we discuss that this statute will likely help streamline the interconnection process for smaller, lower-impact distributed generators, and investigating other ways in which existing queue processes can be reformed to streamline interconnections would be appropriate.
216B.1691 subd. 2h	Distributed Solar Energy Standard Docket No. E002, E015, E017/CI-23-403	In *Appendix A1: System Planning*, we discuss how the August 2023 forecast vintage used in the LoadSEER DER Scenario Modeling for CSGs included a forecast for solar that will meet the DSES. Our methodology and results can be found in Section II.C.7. of the same appendix.

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Date: February 15, 2024

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Xcel Energy		Information Request No.	29
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Supply Chain Issues and Procurements
Reference(s): IDP, p. 10

In the referenced section, Xcel discusses that it is "[p]lacing long-term purchase orders for new equipment into 2024 and beyond."

a. Has Xcel considered the impact of placing long-term purchase orders into 2024 and beyond on the costs of procuring this equipment? How is Xcel managing the risk that placing long-term orders for new equipment could result in the Company paying more than ultimately necessary for this equipment?
b. Has Xcel considered the impact of placing long-term purchase orders into 2024 and beyond on the potential for utilizing non-wires alternatives instead of traditional solutions? Does placing long-term purchase orders preclude the Company from considering NWAs for the given need? Please explain in detail.

Response:
a. Yes. Due to the long lead time of some equipment, orders must be placed one and a half to four years in advance. If the orders are not placed, projects could be delayed and there could be risks to the system that could be detrimental to existing and future customers. As demand for electrical equipment is projected to increase, the Company believes that the risks to delaying the ordering of long lead equipment outweigh the small risk that the equipment will decrease in cost over the next one to four years.
b. The NWA initial screening process analyzes projects in the budget that have in-service dates in years 3-5 in the budget. See Section IV on pages 12 and 13 of Appendix F: Non-Wires Alternative Analysis for more information on how long lead purchase orders and project timelines impact the NWA initial screen. However, whether a long-term purchase has already been placed at the time of the NWA initial screen is not considered as a filter.

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Xcel Energy		Information Request No.	30
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Distribution Strategy and Plan
Reference(s): IDP, p. 14

In the referenced section, Xcel indicates that it is "striving to load feeders to approximately 75 percent of maximum capacity."

a. Does the objective of loading feeders to approximately 75 percent of maximum capacity differ from current or historical practices? Please explain in detail.
b. On what basis has Xcel determined the goal of 75 percent of maximum capacity for feeder loading? Please explain in detail.
c. Has Xcel evaluated the cost implications of striving to load feeders to approximately 75 percent of maximum capacity rather than adopting a different standard for feeder loading? Please explain in detail.

Response:
a. No, it has been our historical guideline to load feeders to less than 75 percent of the maximum capacity. However, in the past, capacity mitigations were not required to be initiated for feeders until the N-0 loading exceeded 106 percent of the maximum capacity. Now, we are initiating capacity projects for feeders when the loading exceeds the desired utilization of 75 percent of the maximum capacity.
b. Please refer to Appendix A1, Section C - Planning Criteria and Design guideline (pages 13-18) for more information on the basis of the 75 percent loading guideline.
c. While we have begun evaluations of the cost implications, we are still refining our methodology for an accurate estimate.

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Xcel Energy		Information Request No.	31
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

<u>Question:</u>
Topic: Capital Expenditures Budget
Reference(s): IDP, pp. 20-21

On page 20 of the IDP, Xcel indicates the following:

> "Preparing the distribution system for the future requires a fundamental and proactive shift in the planning and budgeting framework which has been able to meet the needs of our customers over the last century. Now, our budget framework incorporates not only the necessary work to maintain existing infrastructure, but also the investments needed in new and expanded infrastructure, technology, and workforce to prepare for the future and achieve the strategic outcomes of enabling the clean energy transition, maintaining and enhancing reliability and resilience, and modernizing our customers' interactions with the distribution grid. The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future."

a. Referring to Table 2 on page 21 of the IDP, please indicate the share of the annual budget for each IDP category, for each year provided in this table, that is not for maintaining existing infrastructure.

b. Referring to Table 2 on page 21 of the IDP, please indicate how much of the total budget presented for each year is for capital expenditures to ensure that the Company is ready for anticipated future changes associated with electrification and increased penetration of DER and not to meet present system needs. Please explain in detail and cite to all relevant supporting sections of the IDP and appendices.

<u>Response:</u>

a. Table 2 shows the capital expenditures budget. None of the capital budget is used to maintain existing infrastructure. Maintenance costs are captured in the O&M budget in Table 3, page 22 of the IDP.

b. Individual projects within each category are not identified as either addressing present system needs or addressing anticipated future needs. Projects that address present needs and projects that address future needs are not mutually exclusive. Generally, discretionary projects are prioritized based on existing or anticipated near-term future system needs; in either case, the scopes are developed for such projects to ensure their adequacy in contributing to long-term system needs.

Preparer:	Brian Monson
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Date:	February 15, 2024

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Xcel Energy		Information Request No.	32
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Proactive System Upgrades for DER hosting capacity
Reference(s): IDP, p. 21

On page 21 of the IDP, Xcel indicates the following:

> "Of note, in the five-year budget, starting in 2025 we have included a placeholder estimate, totaling $190 million, for proactive system upgrades to increase DER hosting capacity. We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota. That said, we have not yet identified specific uses for this funding – it is intended solely as a placeholder at this time, subject to change based on stakeholder and Commission feedback and additional analysis."

a. How has Xcel determined that the placeholder estimate should be $190 million? Please provide any supporting analyses and materials.
b. Please describe in detail the proactive system upgrades that Xcel contemplates.
c. Does Xcel intend to seek recovery of this $190 million? If so, when and through what mechanism?
d. What "additional analysis" does Xcel intend to undertake.

Response:
a. $190 million was intended to be a high-level indication of how much system upgrades could cost and was included based on feedback from stakeholders about what investments they would like to see in our distribution system in relation to hosting capacity. We started with an assumption of $10 million for the first year, as it would take time to identify and initiate projects. For each year after, we allocated an additional $60 million as an indication of the funding that may be necessary. The $190 million was not meant to represent the total of how much funding would be required to implement system upgrades, but simply a starting point to be balanced with affordability and public policy

considerations. As discussed in Appendix I: Distribution System Upgrades of the IDP, we indicated that the total 30-year cost of distribution upgrades to accommodate the forecasted solar adoption could exceed $1 billion.

b. The proactive system upgrades the Company would contemplate would be infrastructure investments. These investments could be projects that alleviate feeders or substations that are constrained by the Technical Planning Standard (TPS), or other investments similar to those discussed in our November 1, 2023, Proposed Program Plan in Docket No. E002/M-23-458. At this time, we have not identified any specific projects we would consider pursuing beyond those identified in Docket No. E002/M-23-458.

c. Yes, we would look to recover costs from system upgrades. We would welcome feedback on this issue and reference Section III of Appendix I: Distribution System Upgrades of the IDP for suggestions on alternative cost allocation methods for potential system upgrade projects.

d. The Company would refine the cost estimate based on developing actual projects. We would do these additional analyses after receiving feedback or direction from the Commission and stakeholders on investment priorities. Once we have actual projects identified, we would also look at the rate impacts of different cost recovery mechanisms depending on how the costs are allocated.

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Department:	NSPM Regulatory
Telephone:	madeline.k.lydon@excelenergy.com
Date:	February 15, 2024

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Xcel Energy		Information Request No.	33
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Grid Reinforcements Program
Reference(s): IDP, p. 21

On page 21 of the IDP, Xcel states refers to the Grid Reinforcements Program, which includes "proactive planning and installation of substations and feeders, particularly in congested metropolitan areas."

a. Please describe this program in detail.
b. Please indicate past and projected future investments undertaken in conjunction with this program, and how these investments have been/will be recovered.

Response:
a. This program involves making upgrades to our distribution system to enable it to handle increased load associated with increased EV adoption as well as electrification of other sectors of the economy. An example of a project that is part of this program is our initiative to replace undersized residential transformers that have experienced overloading or are determined to be at risk of failure in the coming years. Adding load to these undersized transformers (e.g., adding a level 2 EV charger) could overload the transformer and cause outages. Proactively replacing these transformers and conductors will make the grid more flexible by enabling the accommodation of load growth while minimizing reliability issues for customers. This program is also proposing to undertake proactive grid reinforcement efforts in areas on our system that might experience substantial future load growth due to normal economic development and future Medium and Heavy Duty (M/HD) EV charging and public direct current fast charging. These projects will focus in making proactive upgrades at the feeder and substation level. The Company is still evaluating the methodology that will be used to identify these areas, determine

the magnitude of the EV load and the impact to the system to propose the needed projects.

b. Past and planned investments are shown in the Table 1 below. No cost recovery has been approved for this program to date; cost recovery for 2022, 2023, and 2024 was denied in the Company's most recent Multi-Year Rate Plan (Docket No. E002/GR-21-630). However, we intend to request cost recovery for this program in a future rate case when appropriate.

Table 1
Past and Planned Investments for Grid Reinforcement Programs

Project Description	2022	2023	2024	2025	2026	2027	2028	Grand Total
MN OH Grid Reinforcement	$40,259	$77,014						$117,273
MN UG Grid Reinforcement		$10,049						$10,049
MN Grid Reinforcements				$16,000,000	$20,000,000	$46,360,001	$49,795,000	$132,155,001

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Department: Transportation Electrification
Telephone: 567-377-5958
Date: February 15, 2024

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Xcel Energy		Information Request No.	34
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Cost-Benefit Analysis
Reference(s): IDP, p. 24

On page 24 of the IDP, Xcel indicates that "there is no single universally accepted method of performing a cost benefit analysis."

a. Would Xcel support the standardization of cost-benefit analysis (e.g., through development of a framework by the Commission) for the evaluation of distribution investment evaluation in Minnesota? Please explain in detail.
b. Does Xcel utilize a standardized approach to cost-benefit analysis for distribution investments? Please explain in detail and please provide any guidance materials or other relevant documentation associated with its approach to cost-benefit analysis for distribution investments.

Response:
a. The Company does not support the standardization of CBAs for evaluation of distribution investment evaluation in Minnesota for multiple reasons, including the magnitude of investment indicated by our forecasts. It is simply not efficient to conduct a CBA for all discretionary work. We are concerned that doing so would impede developing the necessary investments to meet our customers' needs for a few reasons discussed below.

   First, the volume of projects in the distribution five-year budget makes CBAs for each project impractical and costly. If we were required to conduct a CBA for all or most discretionary investments, costs would be incurred, which would ultimately be passed onto our customers. In essence, we are concerned that prioritizing additional CBAs would require unnecessary time and funds on investments that are required to serve our customers.

Second, we are concerned that there is not yet sufficient stakeholder consensus on which specific projects are indeed "discretionary" to be able to narrow the list of those projects that could be subjected to a CBA.

Third, a CBA requires project benefits to be identifiable and capable of reduction to a monetary value, and we understand that stakeholders have varying priorities for distribution system investments, which could lead to disagreement on CBA methodologies and assumptions, which could delay important projects.

Additionally, a CBA is only one tool that can be used in assessing the value of a project, and it has limitations. For instance, a CBA does not reflect qualitative benefits and intangible factors. There is a balance that must be struck in mitigating risks, planning for new customers, and addressing the aging of our system while preparing for the future and ensuring that we maintain safe and reliable power for our customers. As an example, long-term asset health projects may not have current benefit greater than the annuitized cost in a CBA, consequently being viewed as projects that can be delayed, even if that is not what would be best for our customers and reliability in the long-term. Due to these nuances, relying on CBAs to inform project prioritization would put the reliability and safety of our grid in jeopardy.

b. One tool the Company uses for project prioritization is risk scoring. This methodology helps the Company prioritize capacity projects based on the reliability and financial benefits of a project compared to the costs. Our risk scores, which identify N-0 overloads and N-1 risks for feeders and substation transformers, estimate the amount of customer minutes out (CMOs) that could arise from load that cannot be served due to either an N-0 overload, or an N-1 outage event, and ascribe a dollar value to that number of minutes. This dollar amount is used as the benefit (avoided cost of CMOs) of a particular capacity project and compared to the cost of that project. Capacity projects have additional benefits beyond the value of avoided CMOs, but they are not assessed in the risk assessment, which is why the risk assessment is not a true CBA, though it functions like one. Instead, the risk assessment gives our planners an indication of projects we may want to fund first based on how cost-effectively they each mitigate future reliability risk, but there are additional factors we use to ultimately determine what projects get priority. However, this methodology does not capture all the benefits of a project, which is why it is only one of the decision-making tools we utilize.

Risk scoring is also used for asset health projects, but unlike with a true CBA, the risk scores for capacity and asset health projects cannot be compared to each other. The basis for how the calculation is done is different: asset health risk analyses look at historical outage data while capacity risk analyses look at the CMOs that would arise from load that cannot be served due to either an N-0 overload or an N-1 outage event. This is far more nuanced than a typical CBA, as a CBA would analyze costs and benefits over the same period.

Additional discussion of how we use the risk score to help prioritize capacity projects and additional factors we consider can be found in Appendix A1: System Planning. Attachment D: Risk Scoring Methodology contains a list of factors we use to prioritize projects from other budget categories that may not be driven by reliability and for which the risks may not be objectively quantifiable.

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Xcel Energy		Information Request No.	35
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Cost-Benefit Analysis
Reference(s): IDP, p. 24

On page 24 of the IDP, Xcel states the following:

> "For example, the Company conducts a robust CBA/risk analysis for capacity projects, as discussed in Appendix A1: System Planning and Attachment D: Risk Scoring Methodology. This risk scoring methodology helps the Company prioritize capacity projects based on the reliability and financial benefits of the projects compared to the costs. While we have called it a risk analysis, it is a CBA."

Please explain why Xcel considers its risk analysis to be a CBA.

Response:
Our risk analyses serve the same function as CBAs because they help the Company prioritize capacity projects based on the reliability and financial benefits of the projects compared to the costs. This has been our practice for several years and was discussed in previous IDPs (Docket Nos. E002/M-19-666 and E002/M-21-694). However, while risk analyses and CBAs serve the same function, they are not equivalent. Our risk scores, which identify N-0 overloads and N-1 risks for feeders and substation transformers, estimate the amount of customer minutes out (CMOs) that could arise from load that cannot be served due to either an N-0 overload, or an N-1 outage event, and ascribe a dollar value to that number of minutes. This dollar amount is used as the benefit (avoided cost of CMOs) of a particular capacity project and compared to the cost of that project. Capacity projects have additional benefits beyond the value of avoided CMOs, but they are not assessed in the risk assessment, which is why the risk assessment is not a true CBA, though it functions like one. Instead, the risk assessment gives our planners an indication of projects we may want to fund first based on how cost-effectively they each mitigate future reliability risk, but there are additional factors we use to ultimately determine what projects get priority.

Risk scoring is also used for asset health projects, but unlike with a true CBA, the risk scores for capacity and asset health projects can't be compared to each other, because the basis for how the calculation is done is different: asset health risk analyses look at historical outage data while capacity risk analyses look at the CMOs that would arise from load that cannot be served due to either an N-0 overload, or an N-1 outage event. This is far more nuanced than a typical CBA, as a CBA would analyze costs and benefits over the same period.

There are additional reasons a risk analysis is more appropriate than a typical CBA for capacity and asset health projects. First, the Company must provide reliable electricity to all our customers, and relying on a standard CBA to determine which projects are funded would not serve this duty. In the same vein, with a typical CBA, many projects affecting feeder circuits in more rural areas of our service territory would be unlikely to pencil out when compared to the more customer-dense and shorter circuits found in developed areas, but we must do these projects, regardless of the cost-benefit ratio to provide these customers with reliable power.

More discussion about how we use the risk score to help prioritize capacity projects and the additional factors we consider can be found in Appendix A1: System Planning. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors, which are listed in Attachment D: Risk Scoring Methodology.

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Xcel Energy		Information Request No.	36
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Cost-Benefit Analysis
Reference(s): IDP, p. 24

On page 24 of the IDP, Xcel states the following:

> "Given the magnitude of investment indicated by our forecasts of load and DER in this DSP, however, it is not efficient to conduct a CBA for all discretionary work, and we are concerned that this will impede developing the necessary investments to meet our customer's needs."

Does Xcel support the establishment of a cost threshold for conducting cost-benefit analysis, whereby cost-benefit analysis would be required only for projects exceeding this threshold? Please explain in detail.

Response:
The Company would not support the establishment of a cost threshold for conducting our analysis, as performing an analysis is not appropriate for all projects. The risk score, the ratio of the annual reliability and financial benefits over the annuitized total cost of the project across the project life, is calculated for specific types of projects and risks: capacity (overloads) and reliability (contingency). The calculation of a risk score is not based on a dollar threshold. Instead, it is based on project and risk type. For example, a new business project (whether above or below a threshold) having a risk score would not provide additional planning value since we are required to serve new customers and the project would be funded.

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Xcel Energy		Information Request No.	37
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Cost-Benefit Analysis
Reference(s): IDP, p. 25

On page 25 of the IDP, Xcel states the following:

> "…we believe strategically applying CBAs to program level investments would be valuable and will work towards evaluating and developing an approach to do so."

Please detail the steps that Xcel has taken and/or will take to evaluate and develop an approach for strategically applying CBAs to program level investments.

Response:
We conduct CBAs for project categories where one is reasonably feasible and useful – such as when there is a definitive project for which there are identifiable benefits that can be expressed as a monetary value. We have started the process of examining how CBAs could be effectively and strategically applied to program level investments. However, since we are in the preliminary stages of this, we do not have any concrete information to share about the feasibility or potential approach.

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Xcel Energy		Information Request No.	38
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: IDP and Rate Cases
Reference(s): IDP, p. 25

On page 25 of the IDP, Xcel states with respect to the rate case process and the IDP process:

> "…there may be small process adjustments that could be helpful to mitigate certain challenges inherent in the fact that rate cases and IDPs are two separate proceedings with separate scopes and purposes."

Please describe the process adjustments that could be helpful in mitigating the aforementioned challenges.

Response:
It is important to continue to acknowledge that rate cases and the Integrated Distribution Plan (IDP) are inherently different with different scopes and purposes. Rate cases provide a vehicle for the Commission to evaluate utility financial performance and prudency, while IDPs are intended to present a transparent view into the planning process of the distribution grid. The primary purpose of that planning process is to identify and mitigate existing or impending capacity issues to ensure reliability for customers. The outcome is a series of proposed risk mitigations that become an input into the overall distribution business area budgeting process; therefore, proposed mitigations may or may not be funded when compared with other proposed distribution system expenditures. All distribution system investments are weighed and prioritized in the budgeting process using criteria that considers our obligation to provide safe, adequate, efficient, and reasonable service, along with customer cost implications, and prevailing policy objectives. Overall, Distribution business area investment levels are reviewed and approved as part of a general rate case.

However, as explained on pages 5, 27, 28, and 29 of our IDP, a process adjustment that we believe would be helpful to mitigate certain challenges between the rate case and IDP would be to remove the requirement that financial information be reported in IDP-specific categories. This refinement would allow the Company to report financials in the same budget categories across dockets, facilitating easier comparisons of financial information across proceedings and over time.

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Xcel Energy		Information Request No.	39
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Timing of Rate Cases
Reference(s): IDP, pp. 25-26

Does Xcel know when it will make its next rate case filing? Please provide any such plans.

Response:
The Company is currently under a multi-year rate plan (MYRP) for our electric jurisdiction as approved in Docket No. E002/GR-21-630. The current MYRP expires at the end of 2024, meaning the earliest the Company could file an electric rate case application in Minnesota would be in the Fall of 2024 for rates to take effect in 2025. The Company will be evaluating the need to file a rate case in the months ahead.

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Xcel Energy		Information Request No.	40
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Virtual Power Plants, Xcel CO Renewable Battery Connect program
Reference(s): Xcel Energy 2023 Integrated Distribution Plan; Appendix B1

1. Please describe how the costs to Xcel Colorado from providing per kW and annual participation incentives for the Renewable Battery Connect program participants are recovered.
2. Please provide a detailed discussion of how the Company plans to leverage the lessons learned from the Colorado Renewable Battery Connect program to inform the implementation of a similar product in Minnesota, including a discussion of the disparate regulatory and statutory requirements in each state regarding energy storage in retail electricity markets.
3. Please describe the criteria and metrics used by the Company to select SolarEdge and Tesla as battery vendors eligible for participation in the Renewable Battery Connect program and explain the reasoning why other vendors were declared ineligible.
4. Please describe in detail the process employed by the Company in determining the criteria and methodology used to evaluate the performance benefits of different types of DER (generation, electric vehicles, demand side management and response, and efficiency products) aggregated into a VPP construct. Please include a discussion of which, if any, other technologies other than batteries are in consideration for inclusion in a VPP program in Minnesota, as well as what software platforms (currently deployed or requiring purchase) would be required to operationalize them.

Response:
1. The Renewable Energy Standard Adjustment (RESA) is designed to recover the incremental costs of renewable energy programs (and now storage with the passage of Colorado SB21-261). The incentives for Renewable Battery Connect are being paid to participating customers from RESA collections. Participants receive an upfront incentive of $500 per kW of the storage charge rate, and an annual $100 participation incentive per premise for a term of five years.

Income qualified customers and customers in disproportionately impacted communities are eligible for additional upfront incentives.

2. The Company intends to utilize the lessons learned in Colorado as a program is developed for Minnesota. Specifically, we intend to dispatch participants' batteries as Virtual Power Plants (VPPs) to reduce energy use, which in turn reduces demand and helps stabilize the electric grid when it is stressed. The Company continues to learn about the potential of a battery demand response program to provide grid benefits beyond those seen with no intervention by the Company. Further refinement of event scheduling could show additional savings in the future. The Company works with an evaluation, monitoring, and verification (EM&V) partner for data collection and analysis of battery performance before/during/after load control events in addition to evaluation of the research questions in Colorado, and learnings will be used to inform the design of the Minnesota offering.

   The regulatory guidance differs between Colorado and Minnesota specific to cost recovery of these efforts. In Colorado, the cost recovery mechanism falls to the RESA due to legislation allowing a battery to be considered a renewable energy resource so long as the battery was charged from 100 percent renewable energy. This enabled the funding source used for solar incentives to also be used to provide the lucrative incentives for the batteries participating in the Renewable Battery Connect program in Colorado. In Minnesota, Minnesota Statute 216B.241 allows the Company to include these types of efforts as "load management" through our Energy Optimization and Conservation portfolio.

3. Through a competitive solicitation Request for Proposal (RFP) process conducted in 2019, the Company selected two vendors for the Battery Connect pilot (Tesla and SolarEdge). The bid evaluation included scoring in four categories: cost to deliver requested services, demonstrated experience, likelihood to enroll battery systems, and positive customer experience with battery technology. Within each category, bids were scored on several items ranging from a comprehensive proposal, ability to deliver and meet pilot objectives, experience in the market, existing and planned functionality around load management and demand response, customer validation, data, and cost transparency. The Company has extended both vendor contracts to support Renewable Battery Connect using the VPP software of these vendors. The product will continue to allow the Company to gain familiarity with vendor capabilities and the software in terms of management of batteries and data collection and analysis.

   The Colorado DSP DRMS Compliance Report (Proceeding No. 22A-0189E) filed on December 8, 2023, describes in detail how additional battery manufactures may be included as eligible equipment in Colorado's Renewable Battery Connect (RBC) program, specifically market expansion for RBC integration through more effective management.

4. The Company currently has several methodologies that are used to monitor the performance of our demand response efforts. These have been described at length in Docket No. E002/CI-17-401.[1] These methodologies may evolve over time as new DER types are added to the system and the Company implements operational technologies that allows us to better manage DER for various use cases. The Company views a DERMS platform as a critical technology to integrate VPPs safely and reliably on its system.

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Date:	February 15, 2024	

[1] See Information Requests Responses No. 1,2,3,4,5 in Docket No. E002/CI-17-401 submitted on January 28, 2020.

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Xcel Energy		Information Request No. 41
Docket No.:	E002/M-23-452	
Response To:	Minnesota Department of Commerce	
Requestor:	Peter Teigland, Daniel Tikk	
Date Received:	February 5, 2024	

Question:
Topic: Virtual Power Plants, FERC's January 29, 2024 Reconsideration Order to MISO regarding Order 2222 Tariff
Reference(s): Xcel Energy 2019 Integrated Distribution Plan

1. In advance of MISO's filing of a tariff compliant with FERC Order 2222, has the Company started incorporating assumptions of the impacts of ARCs and third-party DER aggregators entering the market leveraging resources connected to its distribution system? If so, please provide the Company's most up-to-date forecasting and planning assumptions for expected participation of third-party DER or DER aggregators within its Minnesota service territory.
2. Please provide an overview of the Company's expected incremental upgrades to existing grid modernization programs or technology stacks referenced in the IDP (ADMS, FAN/WAN, AMI, etc.) that would be required to support increased participation of VPPs referenced above.

Response:
1. No, due to the timing of FERC's January 29, 2024 Order and MISO's forthcoming filing, the Company could not have incorporated those assumptions into its November 1, 2023 IDP.
2. See response to subpart 1. In addition, in Appendix B1: Grid Modernization of our November 1, 2023, IDP, we discuss potential investments in various grid modernization technologies, including software and other business requirements.

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Xcel Energy		Information Request No. 42
Docket No.:	E002/M-23-452	
Response To:	Minnesota Department of Commerce	
Requestor:	Peter Teigland, Daniel Tikk	
Date Received:	February 5, 2024	

Question:
Topic: Grid modernization, cybersecurity
Reference(s): Xcel Energy 2019 Integrated Distribution Plan

1. Please provide an explanation of how the Company sets budget targets for incremental cybersecurity investments to harden grid modernization equipment and associated data (both at rest and in-transit) relative to the capital investment costs of new distribution-connected intelligent devices deployed in its Minnesota service territory to support these initiatives.

Response:
The Company has a dedicated Enterprise Security and Emergency Management (ESEM) business unit that ensures the safety, reliability, and resilience of our infrastructure. We have built a multi-layered strategy for deciding to prioritize our security investment priorities in the areas of offensive (pro-active) and defensive security. This strategy encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services.

The Company sets budget targets for any jurisdiction's cybersecurity investments through ongoing risk assessments and quantification of risk exposure. This combination of services and products is designed to cover analysis of the following for use in our budgeting process: vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption. Further, the Company is committed to protection of our customers' data and complies with regulatory and legal requirements of each state. The combination of these services provides our business leaders with insights to make evidence-based decisions about investments, partnerships, and products so they can in their budgeting process to budget wisely, improve cyber resilience, and demonstrate due diligence. These factors are incorporated into grid modernization projects from the beginning.

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Xcel Energy		Information Request No.	43
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix A1, p. 27

Given recent supply chain issues affecting the industry, please explain why it is appropriate to wait until the next annual NWA analysis update before issuing market solicitations for deferral opportunities.

Response:
Although there are supply chain issues affecting the industry, any potential risks to missing in-service dates for feasible projects due to them are largely addressed by only looking at NWA projects in years 3-5 of this IDP. Although there is an increase in lead times for procuring equipment such as substation transformers, this timeline is appropriate because the three feasible projects would not require a substation transformer. This timeline accounts for our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to procure an NWA solution. This includes issuing an RFP, obtaining responses, screening the responses, technical and sourcing reviews, and then contract negotiations, regulatory approval, and construction. In the event a solution ultimately proves infeasible (or no RFP bids are received), these timelines could allow us to still construct the traditional project (including ordering a substation transformer, if needed) and still meet the original in-service date required to address the identified capacity risk.

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Date:	February 15, 2024

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Xcel Energy		Information Request No.	44
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 3

Please explain why Xcel does not issue market solicitations for deferral opportunities for all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars.

Response:
Per IDP Requirement 3.E.1, the Company is to conduct an analysis on how NWA's compare in terms of viability, price, and long-term value. Appendix F: Non-Wires Alternative Analysis in the IDP addresses the process that the Company undergoes in conducting an initial screen that identifies this, which includes a process for identifying which projects could be a good fit for market solicitation for deferral.

Cost is not the only indicator of viability of a project for market solicitation. Due to the large quantity of projects in the five-year budget, the large number of resources required to conduct market solicitation, and their respective engineering processes, the NWA process includes a set of five filters that showcase important features of projects that fit well as deferral opportunities.

These five filters are important first steps to ensuring that an NWA project that is issued a market solicitation is capable of meeting the system needs, ensures grid reliability by meeting in-service dates, and addresses specific projects in areas that are best suited for deferral. Additional details about the five filters are highlighted on Appendix F, beginning on page 8.

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Xcel Energy		Information Request No.	45
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

<u>Question:</u>
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 15

In the referenced section, Xcel indicates that its approach is "consistent with NWA load reduction contract structures seen in the industry." Please list the utilities with NWA structures in place that Xcel reviewed to inform its approach.

<u>Response:</u>
The approach described on page 15 of *Appendix F: Non-Wires Alternatives* Analysis is for power purchase agreement (PPA) structures in general, not NWA structures specifically. The Company recently developed an NWA Services Contract for our Colorado service territory, which was approved by the Colorado Commission. We are exploring replicating that contract for use in Minnesota, but do not have anything concrete at this time.

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Xcel Energy		Information Request No.	46
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 20

In the referenced section, Xcel indicates that,

> "this payment to the NWA providers is assumed to be capitalized and recovered through rates."

Please explain why a payment to the NWA providers is assumed to be capitalized and not treated as an expense.

Response:
The NWA analysis assumes that instead of a traditional capital project, the Company is making capital investments for an NWA that defers the need for the traditional project. If payments for an NWA solution are not capitalized, they would be incurred as O&M, which would result in a different methodology for NWA analysis.

Preparer:	Paul Vaynshenk
Title:	Distribution Planning Engineer
Department:	Integrated System Planning
Telephone:	763-493-1683
Date:	February 15, 2024

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Xcel Energy		Information Request No.	47
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 15 and p. 29

In the referenced section, Xcel states "a positive or negative net impact does not absolutely determine whether a project would be cost-beneficial but instead, provides an indication of whether a project would be worth investigating further for an NWA in a market solicitation."

If a negative net impact does not absolutely determine whether a project would be cost-beneficial, please explain Please explain why Xcel does not plan to issue market solicitations for deferral opportunities for all NWA Candidate Projects as shown in Table F - 3.

Response:
All candidate projects in Table F-3 undergo an initial screen, which indicates whether a project is feasible as well as if it has a positive or negative net impact. In the process for identifying the feasibility of a project, one of the key considerations is whether the DER technology is capable of meeting the system need for more than one 24-hour load cycle during a peak event. If the technology is not capable of meeting the need, then no project, regardless of market solicitation, could be a true deferral of the traditional mitigation. Each risk within a mitigation needs to have a feasible NWA that could meet the risk, whether it is an N-0 or N-1 condition. Only three projects in Table F-3 had feasible NWA solutions that could address every risk in the traditional solution.

The three projects in Table F-3 that had feasible NWA solutions did not go for market solicitation, as they have in-service dates of 2028. This gives us time to run our NWA analysis next year, as part of our annual NWA analysis update before additional steps are taken. If any of the projects remain potentially viable and cost-effective, we would then determine next steps in the next IDP Annual Update filing in 2024. The in-service dates of these potentially viable projects are in 2028, which allows enough time for us to move forward with a project or projects after the 2024 analysis is complete.

Preparer:	Paul Vaynshenk
Title:	Distribution Planning Engineer
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Telephone:	763-493-1683
Date:	February 15, 2024

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Xcel Energy		Information Request No.	48
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 26

In the referenced section, Xcel indicates that the WACC is the appropriate rate to use in evaluating NWAs because capital is either debt or equity and WACC represents the average cost Xcel pays for that capital.

a. Does Xcel anticipate it will own and operate all NWA solutions?
b. How will Xcel recover costs of an NWA solution provided by third-party resources?
c. Does Xcel consider demand response and energy efficiency to be capital? Please explain why or why not.

Response:
a. In the initial NWA screening process, the concept of avoided revenue requirement (ARR) split is introduced. In this methodology, the Company does not necessarily own or operate the NWA solutions, but the NWA developer is required to meet the "load reduction requirement" for the magnitude and duration agreed upon in a Power Purchase Agreement (PPA). Additionally, the Company does pay the NWA developer for only the portion of the NWA project that addresses the load reduction requirement.
b. An NWA solution provided by third-party resources would be recovered via capital spend. The NWA analysis assumes that capital spend for an NWA is selected to defer a traditional capacity project that would otherwise be recovered via capital spend.
c. The Company does not consider demand response and energy efficiency to be capital. Demand response and energy efficiency costs incurred by the utility are recovered concurrently and are independent of the discount rate. Some supply-side alternatives that are avoided by demand response and energy efficiency are considered capital costs. These supply-side alternatives are avoided over the lifetime of the demand response and energy efficiency measures, making the

quantification of those costs dependent on the discount rate. The WACC has been determined to be the appropriate discount rate for supply-side alternative costs avoided by demand response, energy efficiency and other NWAs. This discount rate application is independent of whether demand response and energy efficiency are considered capital.

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Date:	February 15, 2024	

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Xcel Energy		Information Request No.	49
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 29

In the referenced section, Xcel indicates it "applied focused DR in an effort to reduce the load and followed that with energy storage and/or solar generation to make up the rest of the deficiency."

a. Does the focused DR represent additional customer participation in a DR program or existing customer enrollment? Please explain.
b. Please explain why Xcel does not apply focused or geotargeted energy efficiency, in addition to what is already included in the load forecast, for each potential NWA project.

Response:
a. The focused DR included in the NWA analysis only includes existing customer enrollment on a feeder level.
b. The Company does not have a geotargeted energy efficiency program. Such a program would require an extremely large data set with very granular customer-specific data that could be used to identify potential impacts to the outcome of an NWA project. It is simply not possible to obtain this information, as information such as customer behind-the-meter equipment and incremental energy efficiency potential for specific customers - as well as the impact it would have to the 24-hour customer demand shape on peak day - would be required. This type of information changes frequently with customer choices the Company is not privy to, such as the exact make and model of appliances. This list of details that could be required is not all-inclusive, but representative of types of data that would be needed for this to be possible.

Preparer:	Paul Vaynshenk
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Date:	February 15, 2024

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Xcel Energy		Information Request No.	50
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 49

Please provide all values, assumptions, calculations, and sources for the "levelized avoided emissions benefit." Provide all calculations in Excel format with formulae intact.

Response:
The value used for the "levelized avoided emissions benefit" was taken from the Company's 2023 Value of Solar compliance filing submitted on September 1, 2022 in Docket No. E002/M-13-867. The live Excel file is available on eDockets as Document ID: 20229-188782-03. We also provide it as Attachment A to this response for convenience.

Preparer:	Paul Vaynshenk
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Department:	Integrated System Planning
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Date:	February 15, 2024

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Xcel Energy		Information Request No.	51
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 29

Please provide the NWA initial screen and all supporting workpapers for each NWA Candidate Projects included in Table F – 3 in Excel format with all formulae intact.

Response:
On February 20, 2024, the Company met with representatives from the Department and Synapse to walk through the NWA initial screen process and workpapers for the NWA candidate projects. We understand that meeting to have largely satisfied this request. In a follow-up to that meeting, it was requested that we provide supporting workpapers for two projects as Attachment A and B to this response. In the workpapers, one project reflects a feasible NWA analysis (Attachment A: TWL065) and another reflects an infeasible NWA analysis (Attachment B: MEL089).

Please note, Attachments A and B are marked as "Non-Public in entirety. Xcel Energy maintains this information as trade secret pursuant to Minn. Stat. §13.37(1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, pursuant to Minn. Rule 7829.0500, we have excised this data from the public version of our filing.

Attachments A and B are marked as "Non-Public" in entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:
Attachment A
1. **Nature of the Material**: Workpaper for an NWA Candidate Project**.**
2. **Authors**: Integrated Distribution System Planning
3. **Importance**: The Company work product is proprietary to the Company based on its economic value from not being generally known and not being readily

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ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

4. **Date the Information was Prepared**: Fall 2023

Attachment B

1. **Nature of the Material**: Workpaper for an NWA Candidate Project**.**
2. **Authors**: Integrated Distribution System Planning
3. **Importance**: The Company work product is proprietary to the Company based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
4. **Date the Information was Prepared**: Fall 2023

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Title:	Regulatory Manager
Department:	NSPM Regulatory
Telephone:	612-337-2268
Date:	February 22, 2024

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Attachments A and B are marked as "Non-Public in entirety. Xcel Energy maintains this information as trade secret pursuant to Minn. Stat. §13.37(1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, pursuant to Minn. Rule 7829.0500, we have excised this data from the public version of our filing.

Attachments A and B are marked as "Non-Public" in entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material:

Attachment A

1. **Nature of the Material**: Workpaper for an NWA Candidate Project**.**
2. **Authors**: Integrated Distribution System Planning
3. **Importance**: The Company work product is proprietary to the Company based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
4. **Date the Information was Prepared**: Fall 2023

Attachment B

1. **Nature of the Material**: Workpaper for an NWA Candidate Project**.**
2. **Authors**: Integrated Distribution System Planning
3. **Importance**: The Company work product is proprietary to the Company based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
4. **Date the Information was Prepared**: Fall 2023

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Xcel Energy		Information Request No.	52
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: NWA
Reference(s): 2023 IDP, Appendix F, p. 29

Refer to Table F – 3: 2023 NWA Candidate Projects – Results Summary.

a. For each candidate project determined to not be feasible, please explain why it was not determined to not be feasible.
b. For each candidate project determined to not be feasible, would additional energy efficiency (beyond what is included in the load forecast) change that outcome? Please explain why or why not?

Response:
a. All projects listed as not feasible were determined to be as such due to having at least one risk for which a battery state of charge could not be high enough to address the load reduction requirement during the first hour it was needed. As discussed in Appendix F: Non-Wires Alternative Analysis, a battery is assumed to make up the remainder of the need after the impacts of existing demand response, existing solar, and incremental solar adoption potential are assessed. If a battery is not able to meet the need after incremental solar generation is maximized, then the project is not feasible.
b. Additional energy efficiency, provided that such incremental energy efficiency could be determined, could have an impact on the outcome depending on how much energy efficiency is incrementally available. However, determining incremental energy efficiency would be incredibly challenging, if not impossible, as doing so would require very granular customer-specific data that could be used to identify potential impacts to the outcome of an NWA project. Please see our response to DOC Information Request 49 for more detail on the feasibility of geotargeted energy efficiency programs.

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Department:	Integrated System Planning
Telephone:	763-493-1683
Date:	February 16, 2024

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Xcel Energy		Information Request No.	53
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

<u>Question:</u>
Topic: HAN
Reference(s): IDP, Appendix J, p. 29.

Please provide the following information regarding the lack of current third-party products which use HAN.

a. Please provide Xcel's market research for third-party products which make use of HAN capability.
b. Does Xcel think that the use of third-party products would vary by state? Is there a reason why third-party products would be available in Colorado but not available in Minnesota?
c. Please provide any internal estimates of when Xcel expects third-party products to be on the market to make use of the HAN capabilities.
d. What are the largest barriers to entry for third-party products that make use of HAN?

<u>Response:</u>

a. The Company reached out to third parties who attended Software Development Kit (SDK) workshops and requested SDK access asking if they were creating or planning to create any products. The Company has not received any responses. Furthermore, we have searched the names of companies who have requested access to the SDK in GitHub and no software applications have appeared under those company names.
b. No.
c. We are not aware of any activities of third parties. The Company is exploring vendor offerings and is open to third parties that would allow us to develop a Demand Side Management (DSM) program design that utilizes the benefits of HAN and AMI for our customers.
d. The only barrier to entry introduced by the Company is that third parties must request access to Xcel Energy's GitHub page. All requests are reviewed and if approved, granted typically within one business day.

Preparer:	Dora Irvine
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Date:	February 15, 2024

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Xcel Energy		Information Request No.	54
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: HAN
Reference(s): IDP, Appendix J, p. 8

If the maximum capabilities of HAN were used by Xcel and third-party products, what features would be available to Xcel and customers? That is, provide a summary of what Xcel envisions as a fully utilized HAN.

Response:
Current meter firmware allows energy data output via the HAN agent. These metrics are:

1. Instantaneous Demand
    a. Real-time meter data in Watts.
2. Current Summation Received (locally produced power)
    a. Accumulated kWh since the meter was installed.
    b. Indicates energy delivered from the customer back to the utility.
    c. If a customer has on-site generation, like rooftop solar, this number will increase when power is being exported back to the utility.
3. Current Summation Delivered (grid produced power)
    a. Accumulated kWh since the meter was installed.
    b. Indicates energy delivered from the utility to the customer.

Our vision is to provide solutions which leverage the energy data insights from smart meters to provide customers with the visibility into the drivers of their energy costs to enable the best choices for their lifestyle, to yield lower energy costs, improve grid reliability, sustainability and decrease centralization of generation resources.

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Xcel Energy		Information Request No.	55
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: My Energy Portal
Reference(s): IDP, Appendix J, pp. 3-15, pp. 22-23.

Please summarize how the functionality of Xcel's My Energy Portal in both Release 1 and Release 2 is dependent on the following technologies: AMI, HAN, and DI. That is, without the existence of the given technology, the functionality could not exist.

Response:
We would like to clarify that My Energy Connection and My Energy Portal are two separate products, the former of which is the primary focus of pages 3-15 and 22-23 in Appendix J: Distributed Intelligence. My Energy Connection is not a portal, it is an application that lets customers view their real-time energy usage. My Energy Portal allows customers to see their 15-minute historical data.

For Release 1, the Home Area Network (HAN) functionality is necessary for the My Energy Connection application to provide users with one-second electric usage data straight from the meter over Wi-Fi. For Release 1 and Release 2, AMI is necessary for the My Energy Connection application to provide our customers with their usage in 15-minute intervals. This can be disaggregated by appliance usage.

DI functionality is not required for either release of My Energy Connection.

Preparer:	Dora Irvine
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Date:	February 15, 2024

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Xcel Energy		Information Request No.	56
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Cost Recovery
Reference(s): IDP, Appendix J, p. 3.

Please provide clarification regarding cost recovery via the following questions.

a. Please clarify the cost recovery of the My Energy Connect application and use-cases of the application. Please also clarify if Xcel has applied for such cost recovery, been approved for such cost recovery, or both.
b. Does the My Energy Connect application have a core functionality which receives one method of cost recovery, with additional functionality receiving possibly different methods of cost recovery?
c. Please confirm that Xcel has not applied for cost recovery, nor been approved for cost recovery, for any DI or HAN investments. If not, please provide a summary of the cost recovery applied for, and/or approved of related to DI and/or HAN investments.

Response:
a. Cost recovery for Program costs will be proposed through an ECO Portfolio plan modification, while cost recovery for Capital costs will be proposed in a future rate case. Neither of these have yet been requested or approved at this time. The use cases of My Energy Connect include the mobile application providing users with real-time meter data, energy usage, and cost information. These capabilities will empower users to shift energy consumption behaviors to and expand depth and breadth of customer engagement across products and services. Additionally, users can better understand their rate during different times of the day and their second-by-second usage when connected to Wi-Fi. Users can see their usage and cost data as soon as 15-minutes after that usage time and can access Savings Tips to help them further lower their energy usage and bill.
b. No.

c. The Company has not applied for cost recovery, nor been approved for cost recovery, for any DI or HAN investments. Please see part a. for additional details regarding cost recovery.

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Date:	February 15, 2024

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Xcel Energy		Information Request No.	57
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Daniel Tikk, Peter Teigland		
Date Received:	February 8, 2024		

Question:
Topic: Distribution Financial Information, Historical Actual Expenditures
Reference(s): Appendix D, Section IV.B.2.

In Xcel's IDP, Appendix D, Section IV.B.2., Xcel provides its actual historical distribution capital profile by IDP category in Figure D-1 on p.16. Xcel also provides the tabular data in live Excel format in Attachment N. Please provide the following information using the same IDP categories and grand totals in one table via Excel spreadsheet on a Minnesota Jurisdictional basis for each year:

a. 2023 actual distribution costs;
b. 2020 to 2023 approved budgets for distribution costs; and
c. 2020 to 2023 rate recovery approved for distribution costs (if not available by IDP categories, please provide the distribution costs by Xcel budget category and total distribution costs).

Response:

a. Actuals for 2023 are not yet available. The Company will provide a supplement to this response on or before March 31, 2024 with the requested 2023 data.
b. Please see Attachment A to this response for the approved budgets for the distribution costs. Please note, the costs are provided by Xcel Energy budget categories rather than IDP categories.
c. Please see Attachment A to this response for the approved recovery of the distribution costs. The approved level of spend for 2022 and 2023 is based on the recent multi-year rate plan (MYRP) outcome with adjustments for disallowed projects (Docket No. E002/GR-21-630). The 2020 and 2021 amounts are based on the 2019 capital spend from the Company's previous MYRP (Docket No. E002/GR-15-826) since no separate proceeding changed the approved capital budget recovery level for 2020 or 2021. As that MYRP was a settlement, no adjustments were made to specific projects from the 2019 budget used in the settlement.

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Date:	February 22, 2024

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Xcel Energy		Information Request No.	58
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Daniel Tikk, Peter Teigland		
Date Received:	February 12, 2024		

Question:
Topic: Grid Modernization and Pilot Projects
Reference(s): IDP, Appendix D, p. 17

Refer to Table D-2. For the "Grid Modernization and Pilot Projects" IDP category, for each of the indicated years, disaggregate the total budget to provide budgeted spending by grid modernization project.

Additionally, for each project and year, indicate the following:

i. How much of the budgeted spending has already been approved by the Commission.
ii. The cost recovery mechanism utilized for any already approved spending.
iii. The cost recovery mechanism intended to be used for any yet approved spending.
iv. Any difference between the budgeted spending that is represented in this table and previous budgets provided for the project, indicating where any previous budgets were provided (i.e., docket/filing).

Response:
Please see Table (DOC-58) 1 below for the disaggregated capital expenditure budget for Grid Modernization by project. The dollar amounts provided in this response are shown as capital expenditures to be consistent with the IDP filing.

Table (DOC-58) 1
Grid Modernization & Pilot Projects Capital Expenditures Budget by Project
($s in Millions)

Project	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ADMS	1.7	0.9	-	-	-	-
AMI	91.0	94.9	37.9	20.2	-	-
FAN	18.1	3.9	0.7	-	-	-
FLISR	4.6	11.6	12.2	15.6	15.6	-
Grid Modernization Program	-	-	5.5	5.1	10.3	10.8
Other	-	-	-	-	7.6	-
Total	115.4	111.3	56.3	40.9	33.5	10.8

i. The Commission approved capital cost caps of $366.3 million and $98.1 million for AMI and FAN, respectively, in its June 28, 2023 Order in the Transmission Cost Recovery (TCR) Rider – Docket No. E002/M-21-814. FLISR project expenditures of $21.6 million were approved in the Company's most recent electric rate case for years 2022 through 2024 – Docket No. E002/GR-21-630 (subject to Capital True-Up). The Commission approved a soft cap of $69.1 million for the ADMS project in its December 10, 2021, Order in the TCR Rider – Docket. No. E002/M-19-721.
ii. The AMI, FAN, and ADMS projects listed in the table above are included in our TCR Rider – current Docket No. E002/M-23-467. All other items were included, if applicable, in the Company's most recent electric rate case – Docket No. E002/GR-21-630.
iii. We intend to use either a TCR rider or future rate case to recover costs not yet approved for these projects, should there be any. AMI, FAN, and ADMS will continue to be recovered in the TCR rider until such time as those projects are rolled into a rate case.
iv. AMI, FAN, and ADMS project budgets used to create Table D-2 in Appendix D: Distribution Financial Information, are the same budget used for the TCR rider in Docket No. E002/M-23-467, so there are no differences for those projects.

The following table shows the capital expenditure budget for the remaining projects in the Company's most recent electric rate case in Docket No. E002/GR-21-630. The "Other" category shown in the table below is for IVVO. IVVO was later removed from the budget and the recovery request in the rate case after the Commission declined certification in the IDP – Docket No. E002/M-19-666. All capital cost differences from the level approved in the last rate case are included in the capital true-up compliance filing submitted on November 3, 2023 in Docket No. E002/GR-21-630. The capital true-up is a one-way mechanism that requires customer refunds when actual capital-related revenue requirements are less than the capital-related revenue requirement amounts approved in the applicable year of the rate case.

Table (DOC-58) 2
Rate Case Capital Expenditures Budget by Project
($s in Millions)

Project	2022	2023	2024	Total
FLISR	3.9	8.9	8.9	21.6
Other	-	-	3.7	3.7

Preparer:	Benjamin Halama	Scott Hafner
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Department:	Revenue Requirements	System Planning and Strategy
Telephone:	612-330-5703	651-229-5537
Date:	February 22, 2024	

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
Public Comments

Docket No. E002/M-23-452

Dated this **1st** day of **March 2024**

/s/Sharon Ferguson

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Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-452_M-23-452
Megan	Hoye	megan.hoye@zefenergy.com	ZEF Energy	323 North Washington Avenue Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-452_M-23-452
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_23-452_M-23-452
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