MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**Thursday July 30, 2026**		**Agenda Item **2**
Company	Dakota Electric Association		
Docket No.	E111/M-25-139		

In the Matter of Dakote Electric Association's 2025 Integrated Distribution Plan

Issues

1. Should the Commission accept or reject Dakota Electric Association's 2025 Integrated Distribution Plan (IDP)?
2. Should the Commission require any additional information or adjust any of the IDP filing requirements for Dakota Electric Association?
3. Should the Commission take any other action related to Dakota Electric Association's IDP?

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✓**Relevant Documents**	**Date**
Dakota Electric Association – Initial Filing	November 3, 2025
Department of Commerce – Initial Comments	March 24, 2026
Dakota Electric Association – Reply Comments	April 14, 2026
Department of Commerce – Reply Comments	May 5, 2026

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I. STATEMENT OF ISSUES

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II. BACKGROUND

The Commission established IDP filing requirements for Dakota Electric Association ("Dakota Electric" or "the Cooperative") in its February 20, 2019 Order Adopting Integrated Distribution Plan Filing Requirements in Docket E111/CI-18-255. The purpose of these requirements is to ensure that the utility's IDP meets the following objectives:

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;
4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and

5. Provide the Commission with the information necessary to understand the utility'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.

On September 16, 2024, the Commission accepted Dakota Electric's 2023 IDP with modified filing requirements in its Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements in Docket E-111/M-23-420.[1] This Order began a series of working groups facilitated by Commission staff to modify the filing requirements in line with the Commission's Order and ahead of the Cooperative's next IDP filing in 2025.

On June 3, 2025, the Commission issued its Notice of Approval of Updated Filing Requirements resulting from the work groups, outlining the newly modified filing requirements for Dakota Electric's 2025 IDP.[2]

On November 3, 2025, Dakota Electric Association submitted its 2025 Integrated Distribution Plan ("IDP").

On November 13, 2025, the Commission issued a Notice of Comment Period asking parties to answer the following questions regarding the 2025 Dakota Electric IDP:

Should the Commission accept or reject Dakota Electric Association's IDP?

Did Dakota Electric adequately address the Commission's IDP filing requirements and prior Orders, as outlined in Attachment A to this notice?

Feedback, comments, and recommendations on the following areas of Dakota Electric's IDP:

a. Non-wires alternatives analysis
b. Planned grid modernization initiatives
c. Forecasted distribution budget
d. Distributed Energy Resources (DER) scenarios and forecasts

Other areas of Dakota Electric's IDP not listed above, along with any other issues or concerns related to this matter.

On March 24, 2026, the Department of Commerce ("the Department") filed initial comments.

On April 14, 2026, Dakota filed reply comments.

On May 5, 2026, the Department filed final reply comments.

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[1] Docket No. E-111/M-23-420, *In the Matter of Dakota Electric Association's 2023 Integrated Distribution Plan*, Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements, September 16, 2024 (hereinafter "2023 IDP Order").

[2] Docket No. E111/CI-18-255/M-23-420/M-25-139, *In the Matter Dakota Electric Association's 2023 Integrated Distribution Plan*, Notice of Approval of Updated Filing Requirements, June 3, 2025 (hereinafter "updated filing requirements approval").

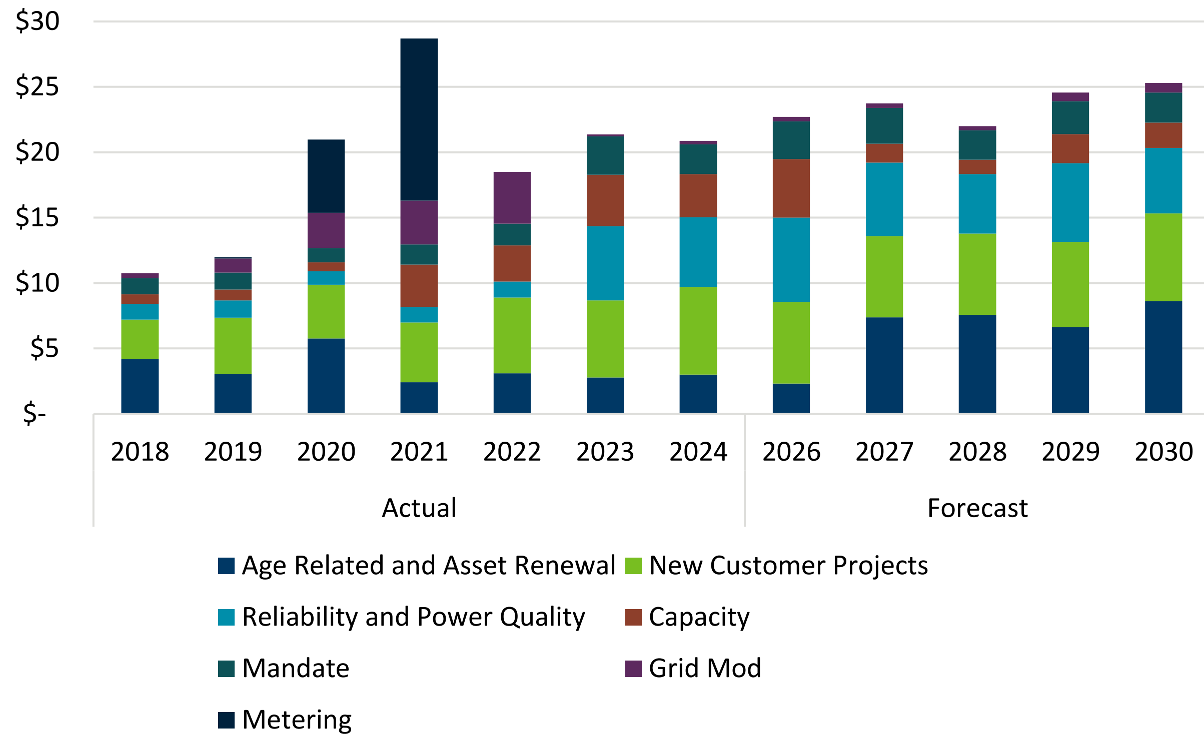
III. IDP DISCUSSION

Dakota Electric is a non-profit electric cooperative regulated by the Commission that serves around 115,000 members in Dakota County and parts of Scott County and Goodhue County.[3] Dakota Electric buys wholesale power from Great River Energy ("Great River") a generation and transmission cooperative.[4] The Cooperative is a summer peaking utility, between 450-500 MW in recent years, driven mostly by air conditioning.

A. Distribution Capital Budget

Dakota Electric outlined its distribution system capital spending for construction over a historic 5-year period (2020-2024) as well as for the next five-year period (2025-2029) broken down by each IDP category (Figure 1).[5]

Figure 1: Historical and Forecasted Capital Spending – IDP Specific Categories ($M)



The Cooperative noted that the forecasted amounts may change since its budget process is still open and must be approved by the Dakota Electric Board. It also stated that it has recently reconfigured some of its budget categories and internal codes used for construction work orders, potentially leading to increases or decreases in certain categories compared to budget

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[3] Docket No. E111/M-25-139, *In the Matter of Dakota Electric Association's 2025 Integrated Distribution Plan*, Dakota Electric Association 2025 IDP Report, November 3, 2025, at 10 (hereinafter "IDP" or "the petition").

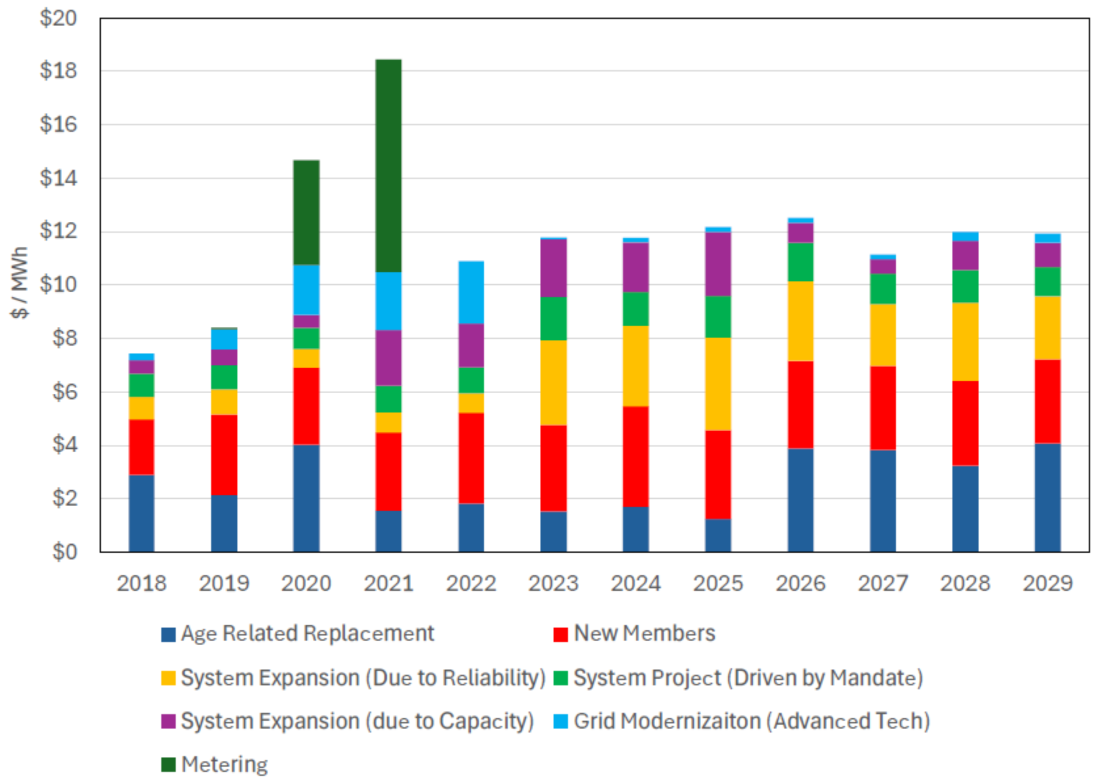
[4] *Id.*, at 11.

[5] Petition, at 86.

category costs in previous IDPs.[6]

The Department provided its graph of Dakota Electric's 5-year distribution budget financial forecast (2025-2029) and including 5 years of historic data (2018-2024), accounting for inflation and energy sales estimates.[7] The Department stated that it was not able to create the graph below with the Association's internal budget categories due to not having requested data for 2018 and 2019 in time, but aimed to perform the analysis in the 2027 IDP.

Figure 2: DEA's Distribution Capex Budget Controlled for Inflation and Energy Sales



In reply, Dakota Electric expressed its concern that the Department normalizing distribution spending to energy sales creates a metric that is not representative of how a distribution system is planned and built.[8] The Association explained that distribution systems must be planned and built to serve all system load regardless of the amount of annual sales, and that normalizing energy sales to distribution spending may draw incomplete parallels. For instance, Dakota Electric's energy sales have been flat over the past 10 years despite the number of customers increasing yearly. The Association provided the example that "maintenance intervals for replacing distribution equipment do not rely on the quantity of energy sales but rather age, lifecycle loading, and environmental conditions. These types of equipment have experienced

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[6] *Id.,* at 85-86.

[7] Docket No. E111/M-25-139, *In the Matter of Dakota Electric Association's 2025 Integrated Distribution Plan*, Comments of the Department of Commerce, March 24, 2026, (hereinafter "Department initial comments"), at 3-4.

[8] Docket No. E111/M-25-139, *In the Matter of Dakota Electric Association's 2025 Integrated Distribution Plan*, Dakota Electric Association Reply Comments, April 14, 2026, (hereinafter "Dakota reply comments"), at 4-5.

cost pressure and inflation over the past several years." The Cooperative indicated that normalizing IDP-specific budget categories of distribution spending to energy sales may miss the broader perspective of rising distribution spending.

Furthermore, the Department stated that Dakota Electric's incentive structure was the inverse of an investor-owned utility due to its duty to keep the lowest costs possible for its members.[9] The Department reasoned that as a result, the Cooperative's distribution planning process may err towards underinvestment instead of over-investment.

In response, the Cooperative cautioned that this was not necessarily true.[10] Dakota Electric stated that it had a strong incentive to pursue distribution planning and grid modernization projects that benefited its members, given that it was a not-for-profit member-owned distribution cooperative.

The Association further explained that its planning process did not err towards under-investment. It noted that it was obligated to provide safe, reliable, and affordable electric service, both by statute and by its members' expectations. Dakota Electric cited its Annual SRSQ Report as evidence of this.

1. <u>Budget Item Allocation Clarification</u>

The Department appreciated Dakota Electric's distribution budget planning, stating that in one instance, the Association lowered the spending of one budget category to increase spending in another (specifically, reducing system expansion due to reliability spending while increasing grid modernization spending, and vice versa).[11] The Department believed that Dakota Electric demonstrated a stable budget that does not put pressure on its members beyond economic inflation.

Dakota Electric answered by clarifying that it had modified its internal IDP budget categories to ease the reporting burden and not to deliberately control distribution spending amounts and in response to a modified filing requirement formulated by the Commission.[12] This reconfiguration may have resulted in some IDP-specific budget categories increasing or decreasing in value. Additionally, Dakota Electric explained that the decrease in its Grid Modernization category was due to the completion of the Cooperative's AGi metering project.

In response, the Department recommended that the Commission require Dakota Electric Association, in its next IDP, to further clarify how its reporting has changed for each of the distribution budget categories.[13] The Department recommended that the discussion include

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[9] Department initial comments, at 1-2.

[10] Docket No. E111/M-25-139, *In the Matter of Dakota Electric Association's 2025 Integrated Distribution Plan*, Comments of the Department of Commerce, May 5, 2026, (hereinafter "Department reply comments"), at 3-4.

[11] Department initial comments, at 7-8.

[12] Dakota reply comments, at 5-6.

[13] Department reply comments, at 4.

examples of the investments that have been reclassified and how the reclassification affects the characterization of the Association's IDP budget compared to the years prior to reconfiguration of its budget reporting categories (**Decision Option 4**).

a. Staff Analysis

Staff believes that there could be some benefit in a one-off compliance filing that explains anything that may have been overlooked in the transition of new budget classifications. Staff expects future budget filings to be more standard, and these explanations won't be necessary.

2. <u>Budget Formation</u>

The Department requested that Dakota Electric explain if it sets a budget limit for each year and how the number is determined and to explain how it formed its budget and made allocation decisions between different investment opportunities.[14]

The Association responded that it constructed a new budget every year and that it did not have a budget limit. However, the Board of Directors could make targeted adjustments to the budget.[15]

Dakota Electric also elaborated that it presented its 3-year construction workplan budget to its Board of Directors, which included new consumers and service rebuilds; mainlines; substations; system improvements; and distribution equipment and automation categories.[16]

Annually, Dakota stated that it analyzes its system based off a variety of categories. For example, new consumers and service rebuilds as well as distribution equipment and automatic budget categories were typically non-site-specific projects whose budgets were grounded in historical trends and forecasts. Mainlines, substations, and system improvement projects were typically site-specific projects which could provide more accuracy in terms of forecasted costs. The Association noted that it could delay an internally driven improvement project to comply with requirements to maintain the construction workplan budget.

The Department requested that Dakota Electric explain how it ensured system condition and reliability maintenance under a restricted budget.[17]

The Cooperative stated that its budgeting process accounted for the periodic maintenance schedules of most of its system equipment.[18] Dakota Electric set aside funds to complete specific ongoing projects, like its cable replacement program or its aging substation program. The Association also highlighted its meter data management system as a way to ensure

[14] Department initial comments, at 8.

[15] Dakota reply comments, at 7.

[16] *Id.*, at 6-7.

[17] Department initial comments, at 9.

[18] Dakota reply comments, at 7-8.

reliability and manage cost pressures.

In reply to Dakota Electric's explanation of its budgeting process, the Department recommended that the Commission require Dakota Electric to include, in its next IDP, a discussion of its construction and process standards that focus on reliability and how the standards are used to build the Association's construction workplan budget (**Decision Option 5**).[19]

3. Incorporating Cost-Effectiveness

The Department requested that Dakota Electric explain how it incorporated cost-effectiveness metrics into its project-level and design-standard review processes.[20]

In response, the Association stated that for its project-level designs, it considers construction feasibility, land accessibility, and future maintenance.[21] However, Dakota Electric noted that "design-standard review processes focus more on engineering analysis rather than cost-effectiveness." It noted that as its distribution system is designed to accommodate future load growth, this also reflected the cost-effectiveness in its distribution system planning process.

Furthermore, the Department requested that Dakota Electric explain how it determined switchgear replacement to be the most cost-effective option.[22]

In reply, the Cooperative explained that the only options are to replace or refurbish switchgear. Refurbishment involves replacing the breakers and relays, though some models are obsolete to the point where replacement of components is no longer a viable option.[23] In addition, Dakota Electric noted that upgrading the communications system would require significant costs and changes. The Association determined that replacing the entire switchgear building was the most reasonable approach.

The Department noted that it intended to continue the discussion on switchgear replacement in the next IDP, including evaluating the option of continuing operations.[24] The Department indicated that it would like Dakota Electric to continue considering and quantifying the tradeoffs and costs in such decisions.

4. Clarification on IDP Filing Requirement A.28

Dakota Electric requested that the Commission clarify filing requirement Section A.28 regarding information on non-Dakota Electric investments made as required for interconnection of a DER

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[19] Department reply comments, at 5.

[20] Department initial comments, at 13.

[21] Dakota reply comments, at 9.

[22] Department initial comments, at 23.

[23] Dakota reply comments, at 13.

[24] Department reply comments, at 13.

system. These are known as "make-ready" costs which the Cooperative has provided below:[25]

Table 1: Total Charges to Members for DER Generation[26]

Category	2020	2021	2022	2023	2024
Application Fees	$23,054	$48,050	$37,832	$27,394	$19,499
Metering	$0	$0	$0	$0	$0
Testing	$0	$0	$0	$0	$0
Make Ready	$870	$7,417	$15,348	$18,043	$20,305
Total	$23,924	$55,467	$53,180	$45,437	$39,804

Dakota Electric indicated that it does not track Contribution-In-Aid-of-Construction (CIAC) payments by feeder or substation.[27] The Cooperative noted that it was unsure if the following CIAC information was relevant to this filing requirement:

Table 2: Historical CIAC Payments ($000)

	2020	2021	2022	2023	2024
Age Related Replacement	$126	$169	$145	$126	$653
System Expansion (Due to Capacity)	$0	$5	$28	$0	$201
System Expansion (Due to Reliability)	$0	$0	$0	$0	$101
New Members	$1,419	$2,484	$2,330	$1,419	$2,117
System Project (Driven by Mandate)	$149	$400	$68	$149	$267
Metering	$0	$0	$0	$0	$0
Grid Modernization (Advanced Technologies)	$0	$0	$0	$0	$0
Annual Total	$1,694	$3,058	$2,572	$1,694	$3,756

a. Staff Analysis

Staff suggests that clarification filing requirement A.28 could be handled through the recommended IDP Improvement Workgroup (**Decision Option 3**) that is discussed in greater depth in the Joint Briefing Paper.

B. Distribution System Overview

All of Dakota Electric's substations are equipped with SCADA (Supervisory Control and Data Acquisition) system software for monitoring and control.[28] The Cooperative continues to add SCADA to distribution feeder equipment, including voltage regulators, reclosers, and key remote switches located on feeders. Additionally, the SCADA system can remotely curtail or

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[25] *Id.,* at 79.

[26] *Make Ready costs only include the amount which was estimated and charged to the member to the Member for the interconnection. Dakota Electric provides a fixed estimate cost for upgrades and any costs above this estimated amount are not charged.

[27] *Id.,* at 91-92.

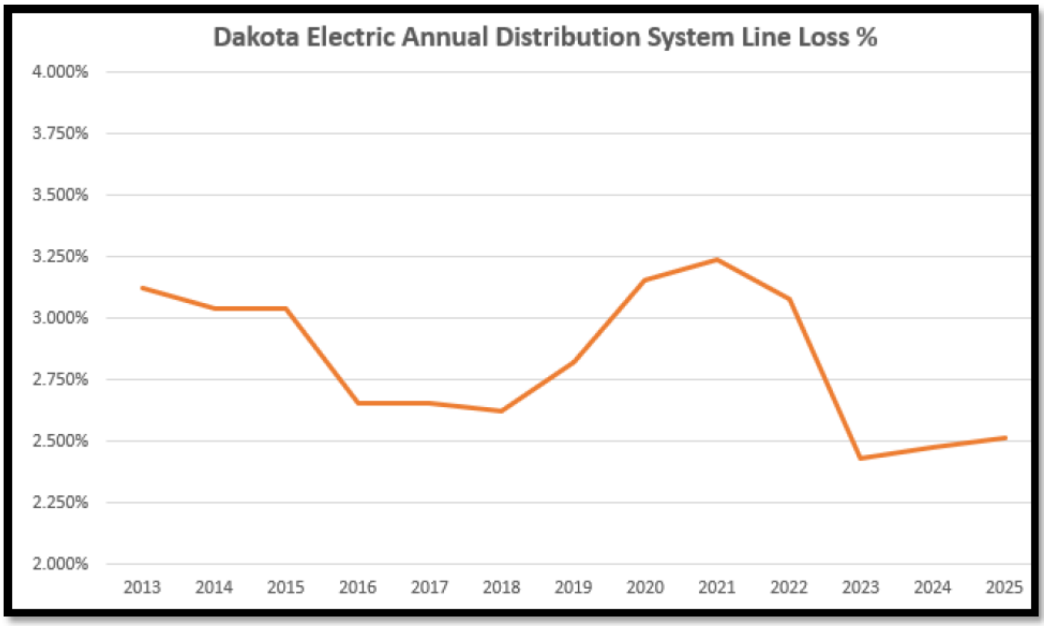
[28] *Id.*, at 66.

disconnect DER systems greater than 1 MW that are monitored through SCADA. The Cooperative has made arrangements with such DER owners to partially curtail output when needed.

1. Distribution System Losses

Dakota Electric has found that unmetered streetlight usage was being counted as part of losses and such data has been removed from the loss calculations for years 2023, 2024, and 2025.[29] The Cooperative included a graph of historic distribution system line losses:[30]

Figure 3: Yearly Distribution System Line Losses (2013-2025)



Note: 2025 data includes average losses from January through September.

2. Load Control

The Cooperative provided a summary table detailing the different types of DER load control programs:[31]

29 *Id.,* 74.
30 *Id.,* at 75.
31 *Id.,* at 85.

Table 3: Load Reduction Estimated by Program Type

Program	Number of Units	MW Connected	MW Reduction Summer	MW Reduction Winter
Air Conditioning	44,098	128	10-20	N/A
Heat Pump	2,809	8.8	3-5	2-8
Heat Device	3,291	28	N/A	5-10
Irrigation	394	24.6	0-12	N/A
Miscellaneous	596	3.5	1	1
Water Heat	7,217	32	4-8	5-10
C&I Interruptible Generation	119	75	50-65	30-50
Curtailment	24	9	2-5	2-5

3. Planned Distribution Capital Projects

Dakota Electric outlined its planned capital projects using a new threshold of $500,000 to include projects as part of the filing requirement.[32] These include projects not completed as of 2025 and those proposed for 2025-2029:

Table 4: Capital Projects by IDP Budget Category 2025-2029

IDP Budget Category	Name of Project	Type of Project	Cost	Timeline
Capacity	Project NOVA (Eagan)	New commercial member	$1.9M	Completion by 2026
	Project Oppidan (Eagan)	New commercial member	$800K	Completion by 2026
	Lakeville Substation	Mainline / Feeder installation	$1.3M	Energized by end of 2025
	Lakeville Station	Substation capacity upgrades	$2.5M	2025
Mandate	Dakota County 91 Road Rebuild	Transmission/distribution relocation	$560K	Completion in 2025
	MnDOT Highway 50 Road Rebuild	Overhead line relocation	$1.5M	Begin by 2026
Age Related Replacement	Dakota Heights	Switchgear replacement	$1.5M	2025
	Fischer Substation	Substation rebuild	$5.6M	2026
	Empire Substation	Switchgear replacement	$1.5M	2026
	Pilot Knob Substation	Switchgear replacement	$1.5M	2027
	Burnsville Substation	Substation rebuild	$6M	Unit 1- 2027; Unit 2- 2028
	Colonial Hills Substation	Substation rebuild	$6M	2029

32 *Id.,* at 92-94.

	New or Relocated Substation	New or relocated substation project	$3M	Possibly 2028–2029
	Old Pole Replacement / Line Rebuilds	System improvement / aging infrastructure replacement	$800K	2025–2029
	Single-Phase Fuse Cabinet Replacements	Equipment replacement	$600K	2026–2029

Staff notes that in the table above, under the New Members section, Project Oppidan refers to a data center project in Eagan, MN, by real estate firm Oppidan Investment Company.[33]

C. Capacity

A portion of Dakota Electric's future planning process for its distribution system involved analyzing existing feeder(s) and substation capacity.[34] Dakota Electric noted that the standard design practices used for the distribution system throughout the past decades have allowed for load growth from the Association's members.[35] The Cooperative pointed to the efficiency gains brought on by appliances such as air conditioners, LED lights, refrigerators, and more that have decreased residential electricity consumption over the past 10-20 years. Dakota Electric remarked that there is a significant portion of its system designed to operate at a higher baseline energy consumption level than currently. The Association used its new AGi meters to find that its distribution transformers were loaded at around 60% at their peak loading. Dakota Electric concluded that this meant that its system had some available capacity for additional load, such as EV charging. Dakota Electric provided data for its total distribution substation capacity for the past 5 years until this IDP filing (2021-2025).[36] The Cooperative indicated that it added 2 new substations over the past 2 years due to new load growth and improved contingency reliability.

Table 5: Historical Total Transformer Substation Capacity

Year	Total Distribution Substation Capacity (kVA)
2021	1,172,500
2022	1,211,700
2023	1,211,700
2024	1,249,030
2025	1,286,360

1. <u>Capacity Planning Standards</u>

The Department asserted that Dakota Electric has experienced relatively flat growth

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33 https://www.datacenterdynamics.com/en/news/oppidan-breaks-ground-on-data-center-in-eagan-minnesota/
34 Petition, at 50.
35 *Id.,* at 43.
36 *Id.*, at 76.

throughout most of its history.[37]

The Cooperative responded by clarifying that it has in fact experienced relatively sustained and even rapid load growth at various points in time.[38] Dakota Electric also noted that while load growth has slowed by the past 20 years and has made forecast accuracy analysis less important, the Cooperative still examined load growth, planning and design assumptions, and budget forecasts for accuracy and usefulness.

Overall, the Department reasoned that Dakota Electric's capacity planning process appeared to be "generalized and future-oriented".[39] The Department observed that during the asset replacement process, the Association sized transformers and conductors based on area-wide needs since it did not rely heavily on location-specific forecasts that can be volatile. Instead, the Department noted that other factors may play a larger role, such as the Association's design standards and the cost effectiveness thereof.

Additionally, since Dakota Electric planned for worst-case scenarios when making asset replacement decisions, the Department stated that the Association used more liberal assumptions for potential load growth and N-1 mitigation risk, which may have led it to oversize its equipment. However, Dakota Electric seemed to use its assets to the maximum potential before making long-term decisions.

D. Reliability

Dakota Electric highlighted that its most recent annual Service Reliability and Service Quality (SRSQ) Report[40] that it filed with the Commission provided a historic overview of the Cooperative's reliability indicators.[41] It included below a chart showing the CAIDI, SAIDI, and SAIFI indices:[42]

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[37] Department initial comments, at 11.

[38] Dakota reply comments, at 6.

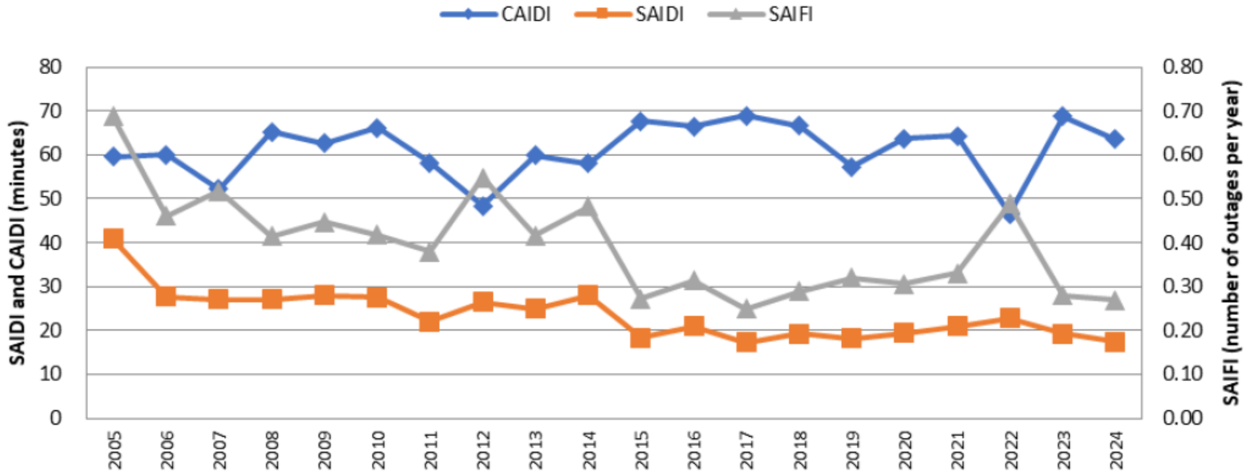
[39] Department initial comments, at 11-12.

[40] Docket No. E111/M-25-28 *In the Matter of Dakota Electric Association 2024 Annual Safety, Reliability and Service Quality Report,* Dakota Electric Association SRSQ Informational Filing, April 1, 2025, (hereinafter "DEA 2024 SRSQ Report").

[41] Petition, at 12.

[42] *Id.*, at 13.

Figure 4: DEA's CAIDI, SAIDI, SAIFI Indices



<u>CAIDI:</u> Customer Average Interruption Duration Index – indicates the yearly average duration of outages in minutes among the members who experienced outages
<u>SAIDI:</u> System Average Interruption Duration Index – indicates the yearly average duration of outages in minutes among all members served
<u>SAIFI:</u> System Average Interruption Frequency Index – indicates the yearly average number of instances in which any member served experienced an outage

In recent years, Dakota Electric has also used CEMI (Customers Experiencing Multiple Interruptions) as an indicator of members who experience multiple outages in a year.

Table 6: Dakota Electric CEMI Performance (2022-2024)

YEAR	CEMI 4	CEMI 5	CEMI 6	CEMI 7
2022	0.0054	0.0006	0	0
2023	0.0081	0.0056	0.0016	0
2024	0.003	0.0005	0	0

The Cooperative noted that vegetation is the leading cause of outages on its system.[43] In 2019, Dakota Electric updates its vegetation right-of-way policy, updated its trimming guidelines and clearance programs, and increased funding for vegetation management. It includes below a map of outages caused by vegetation in 2024.

- Blue = 1 outage
- Red = 4 outages
- Purple = 5 outages

[43] *Id.,* at 14.

Figure 5: Map of Outages in 2024 – Caused by Vegetation

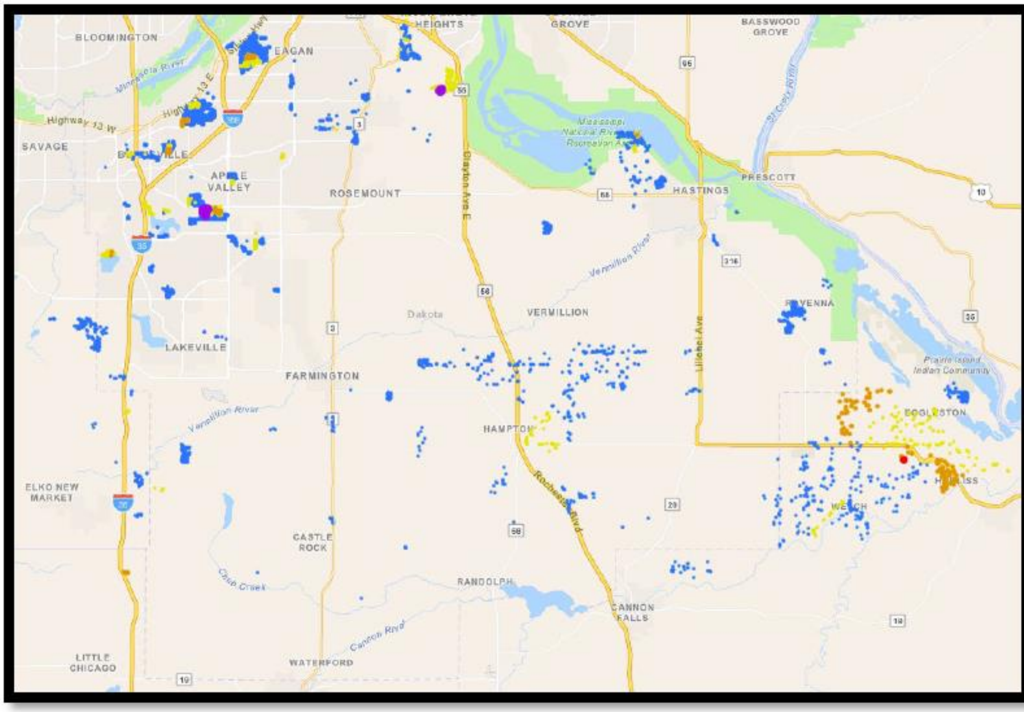
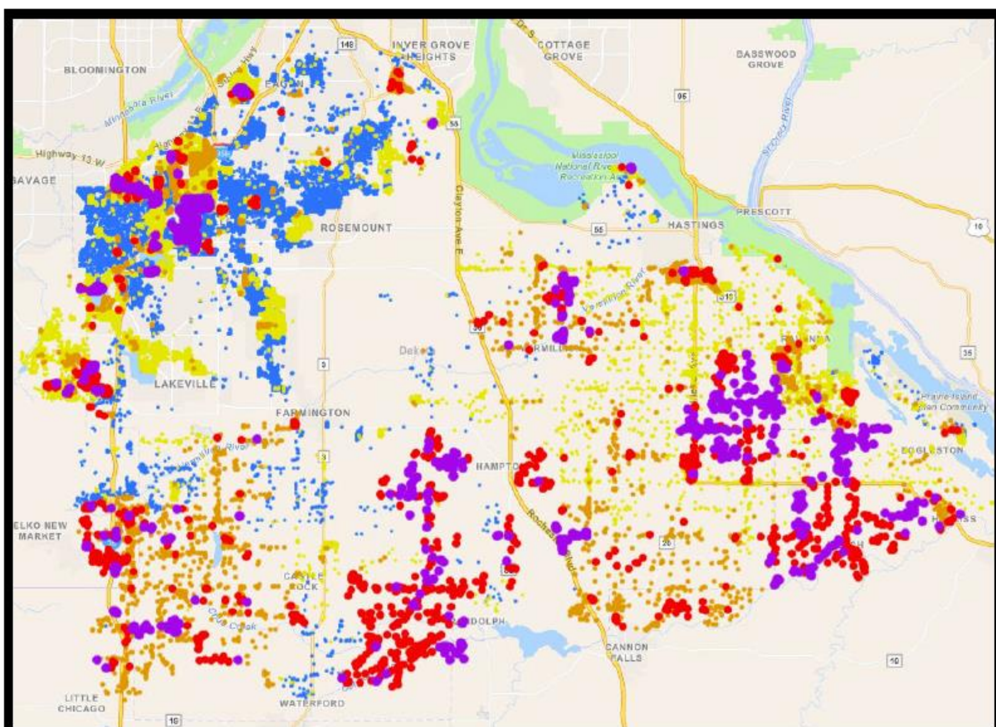


Figure 6: Map of Number of Outages in 2024 – All Causes



The Department noted Dakota Electric's substantial reliability investments, with around $27.6 million in spending over the 5-year forecast period.[44] These investments were composed of the Association's plans to replace all unjacketed underground cables by the end of 2025; strategic

[44] Department initial comments, at 13-15.

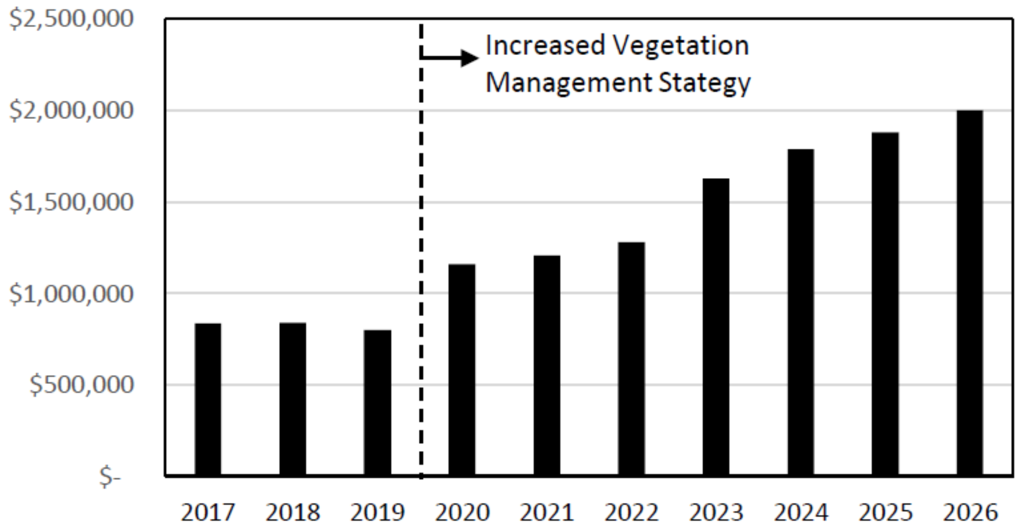
undergrounding (especially relocating back-lot overheads to front-lot underground on residential developments); and replacing overhead lines and poles over 60 years old.

Additionally, the Department highlighted that Dakota Electric's system operated with a high degree of reliability, citing the SAIDI, SAIFI, and CAIDI results from the Association's 2024 SRSQ.[45] The Department appreciated the Association's focus on localized trouble areas and the most outage-prone assets as part of its reliability work.

1. Vegetation Management

The Department remarked that Dakota Electric identified in its 2024 Safety, Reliability, and Service Quality (SRSQ) report that vegetation was the leading cause of outages on its system. The Department noted the connection between that finding and the Association's increase in spending in the vegetation management budget category:

Figure 7: DEA's Vegetation Management Strategy Budget



The Department requested that Dakota Electric explain the number of outages caused by trees in the years 2020, 2021, 2022, and 2025.[46]

In response, Dakota Electric detailed that its data did not currently reflect the reduction in the number of outages caused by trees.[47] The Association expects to take 8-10 years to finish the first cycle of overhead tree trimming. It noted that this was an increase from the 4-5 years initially expected in the 2019 SRSQ report, which was due to tree overgrowth across its system.

In reply, the Department maintained that it found the tree-outage counts "informative but not

45 *Id.,* at 16-18.

46 *Id.,* at 15.

47 Dakota reply comments, at 10.

yet sufficient to demonstrate the magnitude of reliability benefits from the program."[48]

2. Value of Reliability

The Department noted that Dakota Electric did not quantify the monetary value of a customer minutes out (CMO) and thus reasoned that the Cooperative attributed the reduction in CMO to vegetation management.[49] The Department asserted that Dakota Electric could not know the cost effectiveness of its projects if it did not use a quantitative monetized value of CMO to estimate reductions and compare costs. Without a cost effectiveness test based on monetized value of reliability, the Department reasoned that the Association could not determine if the costs justified the outcomes. The Department argued that Dakota Electric should still demonstrate the necessity, deployment, and benefits of each major reliability investment.

The Department recommended that the Commission require Dakota Electric to quantify the value of major reliability and resiliency investments, such as strategic undergrounding, using a recognized customer interruption cost approach (e.g, an Interruption Cost Estimate [ICE] calculator methodology) and to apply that value consistently in cost-benefit comparisons across alternatives (**Decision Option 6**). The ICE calculator methodology is a tool developed by Lawrence Berkeley National Labs (LBNL) and Resource Innovations, Inc used to estimate the monetary costs of electric power interruption events and the benefits provided by reliability improvements.[50]

In reply, the Cooperative disagreed with the Department's recommendation i. Dakota Electric noted that this recommendation would entail significant additional reporting and data collection by the Association.[51] Dakota Electric also believed that this recommendation is more relevant to service quality issues (provided in the annual SRSQ Report) and not distribution system. Dakota Electric added that it could include such requested information in its SRSQ Report but is doubtful of the value-add of such information.

The Department disagreed with Dakota Electric that the metrics in the Association's SRSQ Report covered the Department's value of reliability recommendation.[52] The Department explained that it called on Dakota Electric to use a consistent method to compare reliability tools before the programs are expanded, and that the metrics in the SRSQ Report are not enough to account for an "upfront evaluation of whether the chosen reliability tool is the best-value option."[53]

The Department maintained its recommendation that Dakota Electric quantify the value of major reliability and resiliency investments using a recognized customer interruption cost

[48] Department reply comments, at 9-10.
[49] Department initial comments, at 17.
[50] https://icecalculator.com/
[51] Dakota reply comments, at 11-12.
[52] Department reply comments, at 10-11.
[53] *Id.*

approach, such as an ICE methodology.[54]

The SRSQ Report covered the Department's value of reliability recommendation.[55] The Department explained that it called on Dakota Electric to use a consistent method to compare reliability tools before the programs are expanded, and that the metrics in the SRSQ Report are not enough to account for an "upfront evaluation of whether the chosen reliability tool is the best-value option."

a. Staff Analysis

As discussed in the Joint Briefing Papers, the Department has made similar recommendations related to the value of reliability across all four IDPs. While the Department did not include the decision option to open a new proceeding in its recommendations for OTP, Staff replicates it here for consistency (**Decision Option 7**). As an alternative to the Department's recommendation, Staff suggests holding a technical workshop with LBNL to learn about nationwide best practices prior to requiring utilities to develop methodologies for quantifying the value of reliability improvements (**Decision Option 8**).

3. Strategic Undergrounding

The Department remarked that while Dakota Electric increased the undergrounding of miles overhead lines in recent years, the Cooperative did not yet have a formal strategic undergrounding program.[56] As the Association planned to finish its undergrounding of unjacketed underground cables by the end of 2025, it aimed to shift to strategically underground residential back-lot overhead lines by relocating them as front-lot underground lines. The Department cautioned that more information is needed to determine whether this undergrounding initiative is the best value proposition.

The Department stated that strategic undergrounding is a new initiative that the Association is undertaking, which may increase its overall distribution expenditure. Other upgrades such as FLISR and vegetation management can also improve reliability and may be more cost effective than undergrounding.

The Department recommended that strategic undergrounding be evaluated alongside other reliability tools that can materially reduce outage minutes on targeted feeders (**Decision Option 9**).[57]

The Cooperative agreed with the Department's recommendation and noted that it intended to review and evaluate various reliability tools.[58]

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[54] Department reply comments, at 10.

[55] *Id.*, at 11.

[56] Department initial comments, at 18-19.

[57] *Id.*, at 19.

[58] Dakota reply comments, at 12-13.

E. Wildfire Risk Mitigation

Dakota Electric noted that since its service territory is largely suburban, has a high concentration of underground service, and has minimal forested areas, its overall wildfire risk is lower than that of other utilities.[59] Nevertheless, the Cooperative is taking measures to mitigate this risk, primarily through its vegetation management program and its updated right-of-way policy.

The Department asserted that the IDP is the right venue for Dakota Electric to establish the reasonableness of its wildfire mitigation plan.[60] The Department recommended the Commission require Dakota Electric to file its wildfire mitigation plan as a supplement or attachment in its next IDP. The Department specified that the filing include:

> A map of the Association's wildfire risk and its methodology for creating the map, any identified areas of particularly high fire risk, the probability and potential financial damage of these events, the proposed wildfire mitigation budget, and a full cost benefit analysis of the proposed mitigation measures.
> (**Decision Options 10** and **12**)

Dakota Electric noted that it expects its wildfire mitigation plan to be finished and ready to be implemented by the end of 2026 and agrees with the recommendation by the Department to include its wildfire mitigation plan with its next IDP as a supplement or attachment.[61]

The Department highlighted that since WMPs are quite new for planning dockets and regulatory review, hiring an outside contractor could improve the review process of each utility's WMP by bringing in additional outside insight not in-house at the Department; the Department estimates that the services of the contractor over a 2-year period would total up to $300,000 for all four rate regulated utilities (**Decision Option 13**).[62]

a. Staff Analysis

As noted in the Joint Briefing Papers, Staff recommends that WMP take place in a separate proceeding (**Decision Option 11**).

F. Grid Modernization

Dakota Electric indicated that a significant portion of its operational technology was approaching end-of-life support while the addition of more DERs on the grid required new technologies to enable them.[63] Moreover, the Association stated that many of its internal systems needed to be upgraded to maintain cybersecurity and functionality across its system.

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[59] *Id.,* at 16.

[60] Department initial comments, at 24.

[61] Dakota reply comments, at 15.

[62] Department reply comments, at 15.

[63] *Id.,* at 62.

The Cooperative identified Innovation as a key priority. A timeline of Dakota Electric provides its planned grid modernization projects can be found on page 62 of its IDP filing.

Dakota Electric noted that "Utility Scale Solar is dependent on grant funding, which is still uncertain. Utility Scale BESS is continued exploration and projects would be dependent upon future costs."[64]

Table 7: Grid Modernization Project Descriptions

Grid Modernization Type	Description
AGi Project	As of 2025, Dakota Electric has completed its Advanced Grid Infrastructure (AGi) project to install smart meters with an Advanced Metering Infrastructure (AMI) platform, Load Management platform, and Meter Data Management (MDM) system.[65] Dakota Electric replaced over 125,000 meters and over 50,000 load control receivers with devices using the AGi Radio Frequency mesh communication system.[66] The AGi system provides Dakota Electric with daily meter readings, allowing the Cooperative to align these daily readings with monthly readings to better calculate distribution losses.[67]
Customer Information System	A new CIS to replace its current aging CIS which holds relevant customer data, including usage, billing, and capital credits.[68]
Geographic Information System	Dakota Electric is exploring the feasibility of upgrading its GIS software, developed by ESRI.
Advanced Distribution Management System	Dakota Electric intends to implement an ADMS system in 2028. The Cooperative currently uses several software systems – Outage Management System (OMS), SCADA system, a Load Management System (LMS). An ADMS system would include the functionalities of these different systems within a single program while also providing other functionalities, such as support for DERMS, AGi meter integration, and GIS data integration.
Utility-Scale BESS	Dakota Electric has explored the feasibility of implementing a BESS project, but so far has concluded that the costs would be too high and uneconomic in the current market.
Utility-Scale Solar	Dakota Electric, as part of a consortium of electric cooperatives in Minnesota, has taken part in a grant request to provide funding for a 20-year solar Power Purchase Agreement (PPA).[69]

64 *Id.,* at 62.

65 *Id.,* at 16.

66 *Id.,* at 67.

67 *Id.,* at 74.

68 *Id.,* at 63.

69 *Id.,* at 63-64.

Prairie Island Net Zero Initiative	Dakota Electric agreed with the Prairie Island Community to build a 4.5 MW solar facility which became operational in early 2024.
Electric Vehicles	Dakota Electric stated that it plans to identify known or suspected EV loads on its system and possibly address distribution challenges beforehand.
Power Supply Transformation and Wholesale Power Provisions	Dakota Electric is considering the impact of wholesale power (supplied by Great River) on its distribution system planning, especially given the 2040 Carbon Free Standard (CFS).[70] Two areas where such overlapping impacts are visible are for self-generating solar or storage expansion and for demand response programming.
Aging Substation Replacement	The Cooperative plans to replace aging substation equipment, namely transformers and switchgears, that are over 30 years old.[71]

The Department drew attention to Dakota Electric's Edge DERMS category and Member-Owned ESS Integration category in its Grid Modernization projects timelines.[72] The Department mentioned that since Dakota Electric aims to upgrade its ADMS system in 2028, there was an opportunity for the Association to integrate its load management program into a broader DERMS platform.

1. AGi System

The Commission in Docket No. E111/M-17-821 approved Dakota Electric's AGi project to install Advanced Metering Infrastructure (AMI), and as of this IDP in 2025, the Cooperative has completed its project.[73] Dakota Electric's Advanced Grid Infrastructure (AGi) utilizes smart meters with an Advanced Metering Infrastructure (AMI) platform, Load Management platform, and Meter Data Management (MDM) system.[74] Dakota Electric replaced over 125,000 meters and over 50,000 load control receivers with devices using the AGi Radio Frequency mesh communication system.[75] In early 2024, all meters were replaced with AMI meters except for the few members (around 160) that had opted out. These AGi smart meters provide data in 15-minutes intervals, communicating information such as alarms and event notifications regarding voltage levels. The AGi system provides Dakota Electric with daily meter readings, allowing the Cooperative to align these daily readings with monthly readings to better calculate distribution losses.[76]

Dakota Electric's Advanced Grid Infrastructure (AGi) system has the potential to allow for Demand Voltage Reduction (DVR) allowing the Association to reduce energy consumption by

[70] *Id.,* at 65.

[71] *Id.,* at 53.

[72] Department initial comments, at 25-26.

[73] Petition, at 67.

[74] *Id.,* at 16.

[75] *Id.,* at 67.

[76] *Id.,* at 74.

lowering the voltage supplied to members.[77].

2. Load Management System:

Dakota Electric noted that its AGi system also serves as the backbone for its load management system platform.[78] Dakota Electric operates a robust demand-side load management system that can control or shed up to 100 MW during summer months and 70 MW during winter months.[79] The Cooperative has replaced its load control receivers with new receivers as part of this AGi project. It also mentions that some businesses have full capacity generation that can disconnect their entire load or business campus and redirect the load to their own generation systems. Dakota Electric explains that it worked with some members to create microgrids which isolate a local portion of the Cooperative's distribution feeder along with the member's generation to supply the member's campus during peak demand periods or weather events. The Association noted that without this demand-side management system, its peak electrical demand and costs would be much greater. Dakota Electric coordinates with Great River Energy to reduce the Cooperative's peak electrical demands when GRE's peak demands are the highest.

G. DERs and Forecasting

1. Solar

Dakota Electric has over 1,500 member-owned solar systems, most of which were installed in the past five years.[80] The Cooperative noted that DER installations peaked in 2021 and the number of annual interconnections has declined since then. It includes below a chart of its solar forecast as well as the charts indicating the low, medium, and high percent growth of its members' solar systems.[81]

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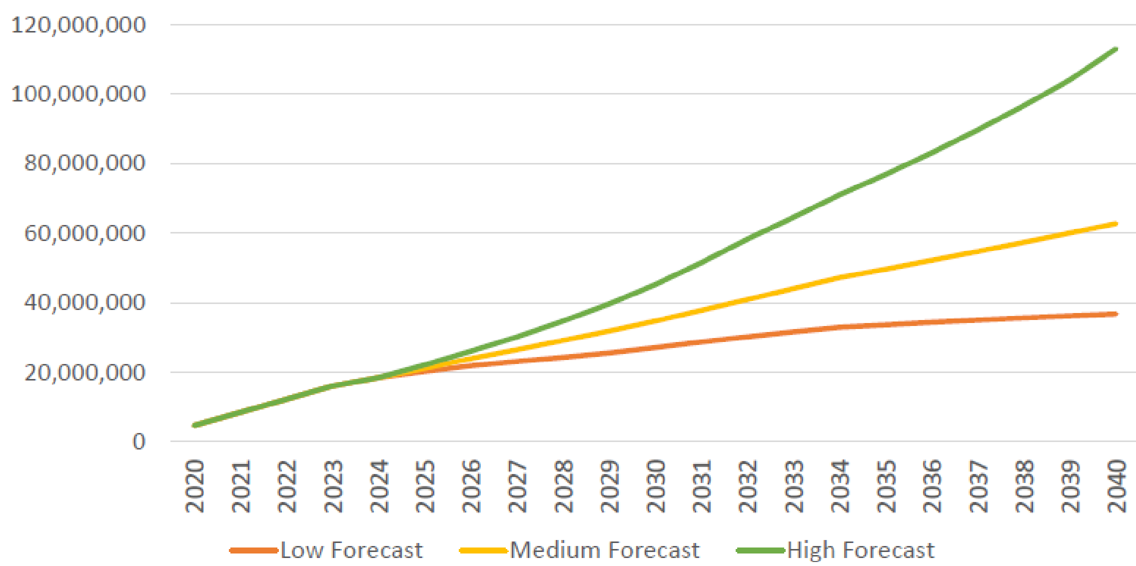
[77] *Id.,* at 17.
[78] *Id.,* at 62.
[79] *Id.,* at 17-18.
[80] Petition, at 25.
[81] *Id.,* at 26-28.

Figure 8: Forecasted Total Energy Production – Member-Owned Solar (kWh)



2. DER Integration

Dakota Electric noted that as the number of DER systems increases, it will need to develop 8,760-hour modeling and incorporate data from the AGi smart meters into that modeling.[82] The Cooperative stated that it will also need to implement an Advanced Distribution Management System (ADMS) to provide more real-time insight into system operations. Dakota Electric expects that as the overall level of DER penetration increases, the aggregate output from DER generators can partially reduce demand at the substation level, and the Cooperative has been using AGi metering data to observe this.

Based on the data collected, the Cooperative mentioned that DER output loss among members is common due to snow coverage in the winter, cloud coverage in the summer, and other environmental conditions.[83] Dakota Electric works with Great River to implement demand side management/load control programs to reduce billing peak demands for members, meaning that DER systems such as member-owned solar produce little to no output during periods of distribution peak demand.

3. Electric Vehicles

Over the past few years, from 2022-2024, Dakota Electric stated that the number of EVs participating in one of its off-peak charging programs has nearly doubled, from 941 to 1,876 EVs.[84] The Cooperative provided below a graph of the total number of EVs forecasted in its service territory, noting that the high forecast is closest to its actual sales over recent years. The top line is the total number of EVs forecasted, and the second line shows the vehicles expected

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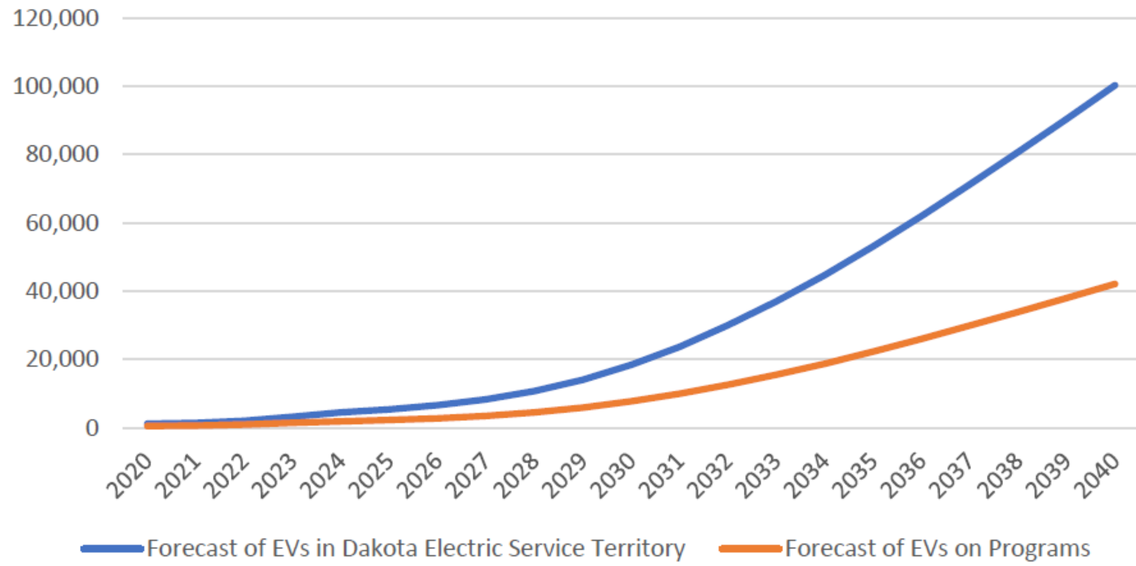
[82] *Id.,* 32.

[83] *Id.*

[84] *Id.,* at 39.

to be on one of the Cooperative's off-peak rates:[85]

Figure 9: Forecast of EVs Charging on the Dakota Electric System (KW)



Dakota Electric stated that in 2025, it had over 1,400 members on its Time of Use (TOU) EV charging rate.[86]

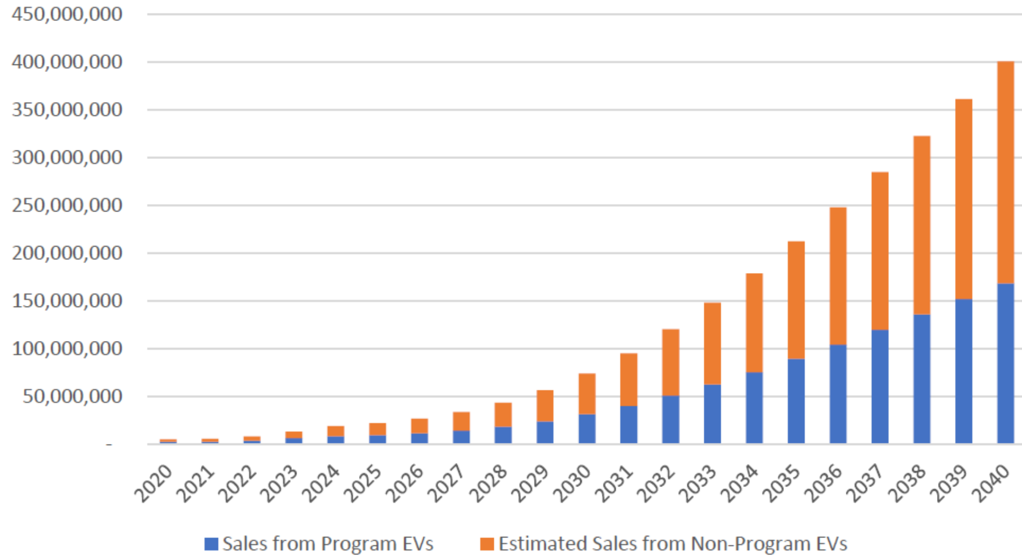
Dakota Electric noted that its average residential household (without an EV) is approximately 700 kWh per month.[87] The 300-400 kWh increase in electrical consumption due to EV charging amounts to a roughly 50% increase in electrical consumption for that residence. The Cooperative provided Figure 10 showing the forecasted increase in electricity consumption due light duty EV adoption. This does not include larger vehicle consumption, such as fleet charging and over-the-road vehicle charging.

85 *Id.,* at 40.

86 *Id.,* at 42.

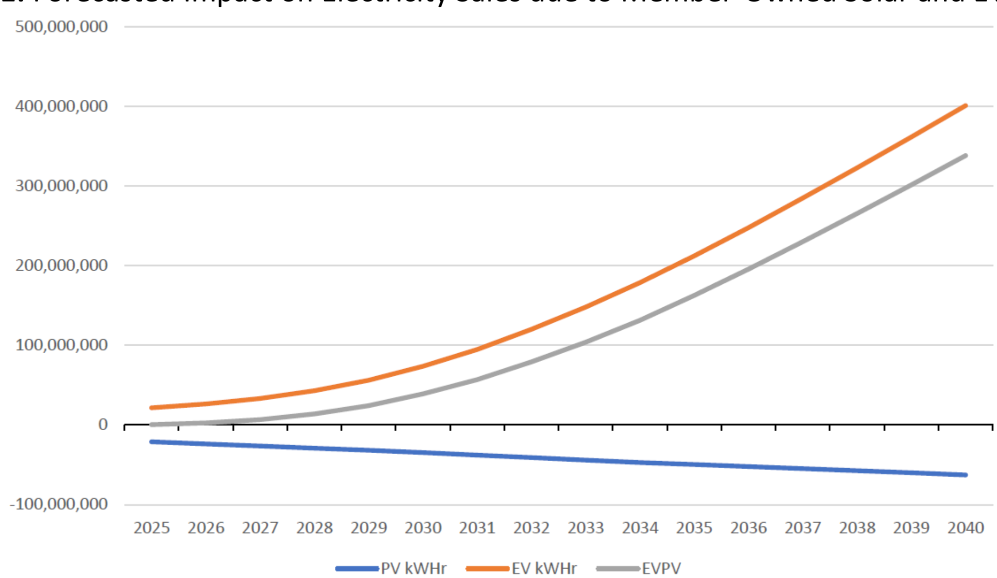
87 *Id.,* at 43.

Figure 10: Forecast of Electrical Consumption by EVs (kWh)



Dakota Electric has developed a new forecast per the updated filing requirements detailing the impact of both EVs and member-owned DER solar on electric retail sales.[88] This forecast is a combination (gray trend line) of the high EV sales forecast with the medium member-owned solar forecast.

Figure 11: Forecasted Impact on Electricity Sales due to Member-Owned Solar and EVs (kWh)



Dakota Electric noted that given the addition of EV charging, the Association has started to observe a shift in when peak demand occurs on the distribution system. The time of distribution peak demand has started to occur periodically in the morning, especially during the winter. Moreover, evening demand peaks are starting to shift later into the day, coinciding with

[88] *Id.,* at 51.

when people charge their EVs and when Dakota Electric's off-peak rates become available. These two changes are moving the high demand energy periods outside of the timeframe when member-owned solar can provide energy to support the system.

4. Battery Storage

Dakota Electric mentioned that at the time of this IDP filing, it did not know of any battery storage units interconnected to its distribution system that export power.[89] Instead, they are all utilized for backup protection. As of October 2025, the Cooperative had 40 BESS interconnected to the distribution system, 11 of which are under review or approved, and all of which are member-owned behind-the-meter. Dakota Electric does not have any utility-scale interconnected BESS.

5. Staff Analysis

Staff appreciates the DER forecasting the Association provides in its IDP. Staff notes that also having DEA's overall load forecast could provide additional context that would assist in the evaluation of future IDPs. For example, Xcel Energy includes their load forecasting separated from DER forecasting. Refinement of the existing scenario and forecast filing requirements to also include the overall load forecast could be considered as part of the IDP improvement workgroup under **Decision Option 3**. Staff anticipates aligning any new material with information that the Cooperative already has to avoid creating any new workload.

H. Load and DER Interconnection Barriers

The Cooperative stated that the interconnection process has been lengthened by the spate of new transmission interconnections, noting that the interconnection study and approval process used to last 1-2 years and has now increased to 3-6 years.[90] Dakota Electric noted that when large load customers, including data centers, express interest in the Cooperative's service territory, the Cooperative must give them long lead times due to the current interconnection timelines. Moreover, Dakota Electric identified two main potential barriers to DER interconnection below:[91]

1. MISO Transmission Injection (Back-feeding) Requirements

MISO (Midcontinent Independent System Operator) has created a process for reviewing the injection of energy from the distribution system back into the transmission system (known as "back-feeding" or "transmission injection").[92] If DER penetration increases to the point where DER output exceeds native load at a distribution substation, leading to back-feeding, then the new MISO rules require that various screens be conducted depending on DER back-feeding. The area transmission utility conducts the first screen while MISO conducts the following screens. In

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[89] *Id.,* at 81-82.

[90] Petition, at 19.

[91] *Id.* 36.

[92] *Id.*, at 36-37.

the context of Dakota Electric, Great River is the transmission service provider and either Great River or Xcel Energy ("Xcel") may be the area transmission utility (ATU) depending on where Dakota Electric's distribution is located (e.g. most of Dakota Electric's distribution system is in Xcel's transmission area, where Xcel would be the ATU in those areas).

> Screen #1: is performed if the DER Net Injection[93] will surpass 1 MW. If it is below 1 MW, then no formal MISO DER Affected System Study (AFS) is required. In the new process, the area transmission utility may still require a Transmission System Impact Study (TSIS). Great River requires a TSIS for aggregated existing and proposed DERs that exceed the daytime minimum load (DML) at a substation and requires a study downpayment of $10,000.
>
> Screen #2: determines if proposed DER causes a greater than 1% change in usage of a transmission facility. If the usage level is greater than 1%, then the DER would fail the screen, and a MISO DER AFS is required.
>
> Screen #3: is performed if the existing and proposed DER combined surpass 5 MW of DER Net Injection onto the system or if the proposed DER fails the second screen. Reaching the 5 MW threshold automatically triggers the MISO DER AFS and requires a $60,000 study downpayment.

These studies are complex and can cause costly and lengthy studies.

2. Residential Solar Installation Costs

Dakota noted that it saw a trend of increasing price per watt costs of installed distributed solar and provides a table below.[94] This can act as a barrier because installers are asked to provide total installation cost without any incentives when submitting applications. The Cooperative was unsure of the exact drivers of these cost increases but pointed to the Covid-19 pandemic and its supply chain constraints. It speculated that the increase in interest rates negatively impacted residential solar applications in 2024 while the federal tax credit changes also decreased demand for solar applications in 2025.

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[93] *Id.,* at 37. DER Net Injection = Native minimum load minus nameplate capacity of all existing and proposed DER at a substation.

[94] *Id.,* at 39.

Table 8: Residential Solar Installation Costs

Year	# of Residential Solar Applications	Sum of kW AC Capacity	Sum of Total Installation Cost	Cost per Installed Watt
2014	3	18.76	$79,300	$4.23
2015	22	264.64	$972,557	$3.68
2016	22	177.67	$584,599	$3.29
2017	37	323.17	$1,038,440	$3.21
2018	50	465.33	$1,481,335	$3.18
2019	110	952.95	$3,408,057	$3.58
2020	219	1,590.39	$6,999,258	$4.40
2021	440	3,580.89	$16,221,839	$4.53
2022	314	2,976.89	$14,138,733	$4.75
2023	257	2,263.93	$11,463,316	$5.06
2024	187	1,794.50	$7,331,858	$4.09

I. Non-Wires Alternatives (NWA)

Dakota Electric has several projects planned for construction over the next five years that surpass two million dollars.[95]

The first set of projects involve the replacement of aging substation equipment, which is discussed later in this briefing paper. Among these substation renewal projects are several that Dakota Electric deems not suitable for an NWA analysis. These are:

- Increase capacity at Lakeville Substation
- Fischer Substation Rebuild
- Burnsville Substation Rebuild
- Colonial Hills Substation Rebuild

The Cooperative elaborated that over the next 10 years, it planned to replace the transformers and switchgears at several substations. The existing equipment is over 30 years old, including many pieces of equipment over 40 years old (the life expectancy of the equipment is 30-40 years). Dakota Electric indicated that as the equipment ages, the risk of failure increases. However, given supply chain issues, the Association cautioned that replacement timelines now stretch into years instead of months. Moreover, Dakota Electric noted the difficulty or inability to procure replacement parts for older switchgear. Coupled with the long lead times for equipment replacement, Dakota Electric highlights that this dual contingency can lead to higher reliability risk for its members. To rectify this problem the Cooperative began its substation rejuvenation projects to replace older substation equipment with new equipment to reduce reliability risk on its system.

The NWA analysis in the IDP looked at the economics and reliability of NWA solutions to replace or delay the capital expenditures for Dakota Electric's substation equipment replacements.

[95] Petition, at 53.

Dakota Electric noted that the main consideration is whether an NWA solution can be installed which meets the system capacity needs if a transformer or substation switchgear fails and whether that NWA solution is able to meet the reliability and capacity needs during the time required to repair or replace the failed substation equipment.

The Department stated that Dakota Electric's NWA timeline reflected long lead times and supply chain issues that have grown with respect to the Association's non-traditional equipment, such as solar and battery energy storage systems.[96] The Department noted that it supported the Association further evaluating strategies that increased the value of NWA benefits, such as delaying capital-intensive distribution projects as well as finding ways to move and reuse NWAs in different locations.

The Department concluded that Dakota Electric satisfied its NWA requirements.

1. Battery Energy Storage System (BESS) Opportunity to Address Transmission Capacity Constraints

Dakota Electric stated that in northeastern Eagan, there is an opportunity for additional growth, wherein the Cooperative could defer transmission and substation voltage upgrades by using an 8 MW/32 MWhr 4-hour BESS to address peak demand periods while serving the rest of the load with the existing infrastructure.[97] Dakota Electric noted that this scenario is of particular interest, as there are two substations in northeastern Eagan served by 69 KV transmission lines, meaning that an upgrade to one substation would trigger an upgrade to the other as well. Dakota Electric estimated that the current infrastructure can sustain 11 MW of additional load until upgrades are needed.

Dakota Electric outlined the cost estimates of either making substation upgrades or deferring the upgrades using the proposed BESS:[98]

i) Upgrade to 115 kV Substation Equipment:

Table 9: Cost Estimates for Upgrading both Substations to 115 kV

Project Year	Description	Cost 2025 Dollars	Present Value @ 5% Rate
Year 1	Substation Transformer (qty 3)	$4,500,000	$4,500,000
	2000A Circuit Switcher (qty 3)	$300,000	$300,000
	Substation Construction / Misc Equip.	$500,000	$500,000
	Total Cost	$5,300,000	$5,300,000

These cost estimates are specifically for upgrades to the substation within the distribution

[96] Department initial comments, at 27-28.

[97] Petition, at 56.

[98] *Id.,* at 58.

system.[99] Potential upgrades to the transmission line to 115 kV would be handled by Great River as part of its transmission budget.

ii) Deferring Transmission Voltage Upgrades With a BESS:

Table 10: Estimated Cost for BESS

Project Year	Description	Cost 2025 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land (1-2 acres)	$600,000	$600,000
	Permitting and Site Development	$100,000	$100,000
	Energy Storage (8 MW - 32 MWHr)	$13,688,000	$13,688,000
Year 10	Substation Transformer (qty 3)	$4,500,000	$2,631,000
	Circuit Switcher (qty 3)	$300,000	$175,404
	Substation Construction / Misc Equip	$500,000	$292,340
	Total Cost	$19,688,000	$17,486,800

Dakota Electric expects that the BESS would be collocated with one of the 69 kV substations to be charged by the grid during the evenings and export capacity during the day to address peak demand.[100] This scenario is based on the assumption that evening and overnight demand would be very low in order to allow the BESS to be recharged by nearby substations. Dakota Electric assumed a 10-year lifespan of the BESS and that the BESS would defer substation upgrades for 10 years.

The Cooperative highlighted two risks associated with the usage of a BESS instead of traditional substation buildout:[101]

- The repair timeframe to replace a failed component within the BESS is unknown and can lead to long outage periods. Such spare parts for BESS are not readily available within hours as are traditional substation parts.
- The Cooperative also assumed that if a neighboring substation is lost, the BESS could still be charged in the evening and overnight given existing redundancy and capacity in the system. The Cooperative noted that this may be a risky assumption, since existing infrastructure is not always available due to storms and other failures.[102]

J. IDP Acceptance and Process

DEA and the Department both recommend acceptance of the Associations' 2025 IDP (**Decision Option 1**).

As discussed in the Joint Briefing Papers, since their inception IDPs have grown and scope,

[99] *Id.*

[100] *Id.,* at 58.

[101] *Id.,* at 59.

[102] *Id.,* at 58-59.

which has strained stakeholder resources. The Department recommended staggering the filings to help alleviate this issue. Staff recommends having Dakota, along with Minnesota Power and Otter Tail Power, file its IDP in even numbered years with the next IDP due in 2028 (**Decision Option 2**).

Staff also recommends the creation of a standing IDP Improvement Workgroup for Dakota, as discussed in the Joint Briefing Papers (**Decision Option 3**).

IV. DECISION OPTIONS

IDP Acceptance and Process

The Commission must select Decision Option 1 or reject Dakota Electric's IDP. It may also select Decision Options 2 and/or 3

1. Accept Dakota Electric Association's 2025 IDP Report as in compliance with IDP Filing Requirements and order points. Acceptance of the 2025 IDP has no bearing on prudency nor certification under Minn. Stat. § 216B.2425, subd. 3.
   (DEA, Department)

2. Require Dakota Electric Association to file its next Integrated Distribution Plan on November 1, 2028 and every 2 years thereafter. Require Dakota Electric Association to file an interim update on November 1 of odd numbered years consisting of Baseline Financial Data (IDP Filing Requirements A.26-A.29).
   (Staff modification of Department)

3. Delegate authority to the Executive Secretary to establish standing IDP Improvement Workgroup for Dakota Electric Association. Delegate authority to the Executive Secretary to approve via notice amended IDP filing requirements if agreement among stakeholders is reached.
   (Staff)

Forecasted Distribution Budget

The Commission may select Decision Options 4 and/or 5.

4. Require Dakota Electric Association, in its next IDP, to further clarify how its reporting has changed for each of the distribution budget categories. The discussion shall include examples of the investments that have been reclassified and how the reclassification affects the characterization of the Association's IDP budget compared to the years prior to reconfiguration of its budget reporting categories.
   (Department)

5. Require Dakota Electric Association to include, in its next IDP, a discussion of its construction and process standards that focus on reliability and how the standards are used to build the Association's construction workplan budget. All recommendations shall be written in bulleted list format in this section.
   (Department)

Reliability

The Commission may select Decision Option any combination of Decision Options 6 through 9.

6. Require DEA to quantify the value of major reliability and resiliency investments, such as strategic undergrounding, using a recognized customer interruption cost approach (e.g, an Interruption Cost Estimate [ICE] calculator methodology) and to apply that value consistently in cost-benefit comparisons across alternatives.
   (Department, DEA)

7. Delegate authority to the Executive Secretary to initiate a new proceeding to discuss the appropriate value of reliability. The initial comment period should address:
   a. The valuation of the cost of unserved energy;
   b. The use of price caps for the cost of unserved energy;
   c. Forecasting methodologies for reliability benefits;
   d. Appropriate uses cases for the value of reliability; and
   e. The potential to employ different values of reliability by customer class.
   (Department)

OR

8. Delegate authority to the Executive Secretary to hold one or more technical workshops facilitated by Commission Staff on how to value reliability in distribution proceedings.
   (Staff)

9. Require that Dakota Electric Association evaluate strategic undergrounding alongside other reliability tools that can materially reduce outage minutes on targeted feeders.
   (Staff interpretation of Department, DEA)

Wildfire Mitigation Plan

The Commission may choose Decision Options 10 or 11. If it does so, it should select Decision Option 12 and may adopt Decision Option 13.

10. Require Dakota Electric to file its wildfire mitigation plan as a supplement or attachment to future IDPs, starting in 2028. *(Department)*

OR

11. Require Dakota Electric Association to file a Wildfire Mitigation Plan in a new docket by [insert date].
    (Staff)

12. Require DEA to include the following information in its Wildfire Mitigation Plan.
    a. A map of the Association's wildfire risk and its methodology for creating the map,
    b. Any identified areas of particularly high fire risk,
    c. The probability and financial damage of these events,
    d. The proposed wildfire mitigation budget,
    e. A full cost benefit analysis of the proposed mitigation measures.

    (Department)

13. Pursuant to Minn. Stat. § 216B.62, subd. 8, request that the Commissioner of the Department of Commerce seek authority from the Commissioner of Management and Budget to incur costs up to $300,000 for specialized services to assist with any proceedings related to the review of wildfire mitigation plans for Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association.
    (Department)