



November 3, 2025

Sasha Bergman, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Subject: Dakota Electric Association 2025 IDP Report

***In the Matter of Distribution System Planning
for Dakota Electric Association
Docket No. E-111/M-25-139***

Dear Ms. Bergman:

On February 20, 2019, the Minnesota Public Utilities Commission (Commission) issued an *Order Adopting Integrated Distribution Plan Filing Requirements* (February 20 Order) in Docket No. E111/CI-18-255. This February Order outlined, in relevant part, the following distribution system plan requirements for Dakota Electric Association (Dakota Electric or Cooperative):

1. Filing Date: Require Dakota Electric to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. 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.

On November 2, 2020, the Commission issued an *Order Accepting Integrated Distribution Plan and Modifying Filing Requirements* (November 2 Order) in Docket No. E111/M-19-674. Ordering Point No. 5 stated:

The Commission delegates authority to the Executive Secretary to convene a process to engage representatives from each of the rate-regulated utilities and stakeholders to review and discuss the Commission's IDP orders for the next round of IDP reports to help ensure that data included in future IDPs is efficiently gathered and presented.

On September 16, 2024, the Commission issued an *Order Accepting 2023 Integrated Distribution Plan and Modifying Filing Requirements* (September 16 Order) in Docket No. E111/M-23-420. In the September 16 Order, the Commission delegated authority to the Executive Secretary to address various filing requirements associated with IDP filings. In addition, Ordering Point Nos. 2 and 5 stated:

The Commission direct Dakota Electric Association to include an Action Plan showing the anticipated timing of grid modernization projects over the next five years in future IDPs.

The Commission delegates authority to the Executive Secretary to work with Dakota Electric Association and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data. The Commission delegates authority to the Executive Secretary to approve via notice a stakeholder agreement on amended filing requirements if one is reached.¹

Dakota Electric notes that we previously submitted two filings regarding the required stakeholder process in Docket No. E111/M-23-420 in this docket. Our September 4, 2025 letter was an invitation to potentially interested stakeholders and a list of discussion topics for the stakeholder meeting. Dakota Electric held a stakeholder meeting on September 30, 2025 where we presented the preliminary findings of our IDP Report. This meeting was attended by other utilities and stakeholders. We filed our presentation material on October 20, 2025 in this docket.

¹ Dakota Electric notes that updated budget categories based on discussions with stakeholders are used in this report.

Dakota Electric Compliance

Dakota Electric submits its 2025 IDP Report in response to the Commission's February 20 Order in Docket No. E111/CI-18-255, its November 2 Order in Docket No. E111/M-19-674, its September 9, 2022 Order in Docket No. E111/M-21-728, its September 16 Order in Docket No. E111/M-23-420, and its June 7, 2023 Order in Docket No. E999/CI-20-800. The 2025 IDP Report also includes the updated filing requirements that were filed by the Commission in its *Notice of Approval of Updated Filing Requirements* in this docket on June 3, 2025.

This filing responds to requirements identified above, and in the Commission's previous IDP orders and other relevant regulatory filings. Dakota Electric has undertaken a substantial effort (through internal staff) to prepare this fourth biennial Integrated Distribution Plan. The attached plan covers the detailed filing requirements outlined in the Commission's previous orders. Dakota Electric notes that the various filing requirements noted in the September 16 Order (Ordering Point Nos. 3 and 4) are currently under review and will be considered in future IDP reports.

Conclusion

Dakota Electric looks forward to comments from interested parties and continuing refinement of this, and future, Integrated Distribution Plans.

Sincerely,

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Certificate of Service

I, Nicole McEathron, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket No. *E-111/M-25-139*

Dated this 3rd day of November 2025

/s/ Nicole McEathron

Nicole McEathron

Dakota Electric Association Integrated Distribution Plan (IDP) Report November 2025



Provided in response to the Minnesota Public Utilities Commission dockets:

E-111/CI -18-255, E-111/M-19-674, E-111/M-21-72, E-111/M-23-420, and E-999/CI-20-800

Filed in Docket No. E-111/M-25-139

2025 Integrated Distribution Plan



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Abbreviations and Common Terms

To assist the reader of Dakota Electric's Integrated Distribution Planning (IDP) report, the following is a list of common terms and abbreviations that are used throughout this report. Other abbreviations may also be explained within the report.

Advanced Distribution Management System (ADMS): Software platform that supports the operation of a distribution system. This includes software such as: Outage Management System (OMS), SCADA system, DERMS, and Load Management systems.

Advance Grid Infrastructure (AGi): This is Dakota Electric's grid modernization project that involved the installation of digital two-way communicating meters and load management infrastructure, integrated with a meter data management system. Additional details can be found in Minnesota Public Utilities Commission (Commission) Docket No. E111/M-17-821.

Advanced Metering Infrastructure (AMI): This is the system which includes an RF mesh communication network coupled with digital meters which are connected to the network. The digital meters can communicate energy information back to the Dakota Electric headquarters in support of energy billing and identification of metering and power quality issues.

Behind-the-Meter (BTM): Refers to a device that is located on the load (consumer) side of Dakota Electric's main service's electric meter.

CAIDI: Customer Average Interruption Duration Index. This is a term used by electric utilities to report on the average outage duration that any given member would experience. CAIDI is equal to SAIDI divided by SAIFI. This index is typically calculated per year.

CEMI: Customers Experiencing Multiple Interruptions. This is a term used by electric utilities to report on instances where individual members are experiencing multiple outages per year. CEMI is based strictly on the number of outages per member/customer in a year and it is not weighted against revenues, sales, or demand.

Demand-side Management (DSM): Also known as Load Management or Load Control. It is a program where Dakota Electric can turn off and on different types of loads using communication systems such as the AGi RF mesh or start/stop member-owned generation using the SCADA system.

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

Distributed Energy Resource Management System (DERMS): Software platform which helps utilities manage consumer loads on their grids. This is to reduce overall and localized electrical demand during peak periods. The DERMS system allows the utility to optimize electrical consumption to reduce the system capacity required to supply the consumer loads.

DER Generation: For this report, DER generation refers to a distributed energy resource that produces or produces or distributes. This term includes energy storage systems but does not include energy efficiency and Demand-side Management.

Energy Efficiency: Measures or programs that target member behavior, equipment, processes, or devices and are designed to reduce the consumption of electricity on either an absolute or per unit of production basis.

Energy Storage Systems (ESS): A system which can store energy to be released for use later, typically using a battery, which is charged by either the distribution grid or distributed generation source.

Electrical Vehicle (EV): A vehicle which uses batteries to provide energy to the vehicle motor. For purposes of this report, EV refers to a vehicle that is licensed to operate on roads of have characteristics similar to a road going vehicle (*i.e.*, not a golf cart or other small vehicle).

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

Kilowatt (kW): This is a unit of electric power. One kilowatt is equal to 1,000 watts and is typically used as a measurement of either capacity available or demand requirements.

Kilowatt-hour (kWh): This is the measurement of energy over a period of time. One kilowatt-hour is equal to 1,000 watts of power for one hour. kWh is often referred to as usage or consumer usage.

Load Control Receiver (LCR): A device installed at a home or business which has a relay (switch) that can turn on or off an appliance upon receiving a command from the utility's Demand-side Management system.

Meter Data Management (MDM): Computer system and database which takes in the data from the AMI meter and stores that information. The MDM provides Dakota Electric with a platform to use the data provided from the AMI meter for billing, identifying metering issues and to identify power quality issues. As part of the overall AGi project, Dakota Electric has integrated the load control receivers (LCR), so that they also provide information to the MDM database platform.

Non-Wires Solutions (NWS): Also referred to as non-wires alternative. This is a type of distribution system solution that is different than the traditional wired solution commonly used today.

Operational Management System (OMS): System that supports the efficient management of the electrical distribution system topology and restoration of outages.

Supervisory Control and Data Acquisition (SCADA): Computer system for gathering and analyzing real-time data. SCADA systems are used to monitor and control a plant or equipment in industries such as energy, oil, telecommunications, and gas refining and transportation.

SAIDI: System Average Interruption Duration Index. This is a system wide average outage duration for an average customer. This index is typically calculated per year.

SAIFI: System Average Interruption Frequency Index. This is a system wide average number of interruptions that an average consumer would experience. This index is typically calculated per year.

1) Introduction

This Integrated Distribution Planning (IDP) report was authorized by the Minnesota Public Utilities Commission (Commission) in its February 20, 2019 Order (IDP Order) in Docket No. E002/CI-18-255. The Commission's IDP Order was subsequently updated on November 2, 2020 in Docket No. E111/M-19-674 and on September 9, 2022 in Docket No. E111/M-21-728, and on September 16, 2023 in Docket No. E111/M-23-420. The Commission's IDP Order requires each regulated electric utility in Minnesota to file an IDP every November 1 of odd numbered years. This is the fourth Integrated Distribution Plan (IDP) report submitted by Dakota Electric. This 2025 version of the IDP report is based upon the Commission's Orders in previous IDP Reports and other regulatory dockets. Dakota Electric Association's (Dakota Electric) approach and philosophy in the IDP, when responding to the questions contained within the Commission's IDP Orders, is to provide information looking at the big picture with an engineering perspective. In some areas, Dakota Electric has added additional information to help the reader understand the topic or provided additional data to help illustrate the issues. Dakota Electric strived to be responsive to the questions and issues raised within the Commission's IDP Orders and in other regulatory dockets.

a) Distribution Planning

Before reviewing or studying an IDP it is important to ask the question, what is Integrated Distribution Planning? The general intent of the IDP reporting process is to provide more visibility into the distribution planning process and provide information on expected or potential distribution system developments for an electric utility. The overall understanding of what an Integrated Distribution Plan includes can be quite different, depending upon the audience. The IDP Orders provided several planning objectives for future IDP reports and included specific data requests and questions which must be answered within the report.

The IDP report also serves as an educational platform which allows Dakota Electric to educate parties on how we conduct distribution planning and provide insight into Dakota Electric's future vision for the electrical distribution system. The creation of this report and the continued bi-annual process for future reports is expected to support greater interaction between Dakota Electric and stakeholders.

Once the idea or principle of integrated distribution planning is introduced, it is important to examine the overall concept of planning and, for an electric distribution system, planning is the process of preparing the distribution system to meet the future electrical requirements of consumers. Unlike many other consumer products, the utility or distribution planner has limited influence on consumer demand. Rates and fees established in utility rate design can have an impact on consumption, but, overall, the distribution planner does not have the ability to shape the electrical profile of the changes to the consumer requirements. The usage profile and consumer requirements are shaped largely by many other influences such as technology and changes to governmental incentives or regulations.

It is imperative that distribution planners are cognizant of these outside influences and are able to incorporate them into their planning assumptions. Failure to adequately account for these influences has the potential to increase system costs and negatively impact consumers or, in the worst-case scenario, impact the overall reliability of the distribution system. Inadequate preparation can result in increased costs from over-forecasting demand that lead to stranded investments that are not needed due to the lower demand levels. Increased costs can also result from equipment damage, emergency construction, or lower reliability and outages resulting from under-forecasting consumer electrical peak demands and not having sufficient capacity to supply the needs of consumers.

These risks underscore the unique requirements of distribution planning. The general belief is that utilities plan their system based on decade timelines and, while this is true for generation and transmission planning, a distribution planner must take a more nuanced approach. Although the distribution planner considers, and prepares, for these long-term trends and consumer influence, it must also be prepared to respond to unexpected consumer demand. An example of these unexpected developments was several years ago when the price of propane was extremely high and many Dakota Electric members switched to electric heating within their homes. These high propane prices were unexpected and the resulting shift to more electric heat increased electrical demand and caused localized equipment overloads and power quality problems for many of our members. As beneficial electrification and electric vehicle (EV) penetration rates increase, there is a risk that similar, fast-moving demand changes (*e.g.*, unexpected changes in EV prices, tax credit modifications) could negatively impact distribution plans. As the energy market continues to evolve, overall planning of the electrical distribution systems is getting more complex, especially with forecasting future electrical requirements.

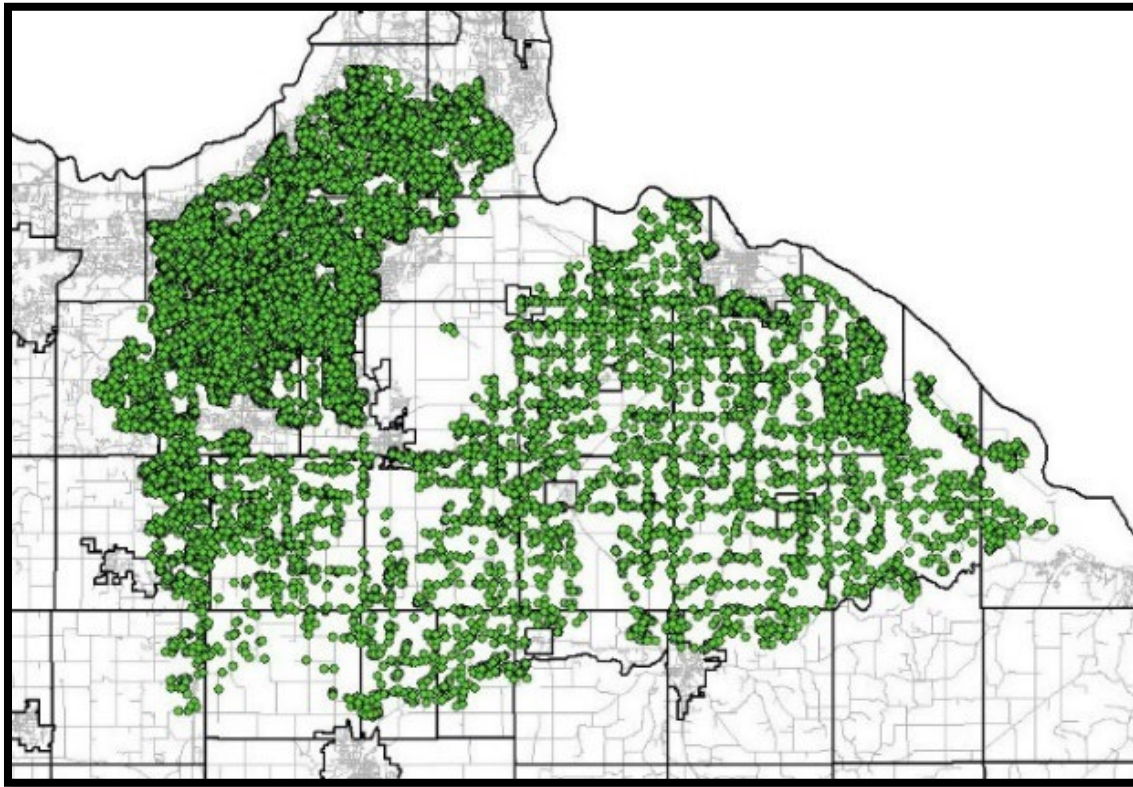
Distribution system planning today includes challenges such as double or triple lead times for receipt of major equipment, increased variability in consumer demand profiles due to the installation and operation of distributed energy resources, and increased localized usage due to electrification. This IDP Report provides insight into what Dakota Electric is doing to mitigate and face these challenges and includes discussion about several issues and topics which are a concern for Dakota Electric and our membership. Dakota Electric highlights some of these issues in the introduction of this report and provides additional, detailed discussion in the body of this document. Dakota Electric also provides additional background and system information in this section.

b) Background Information

Dakota Electric Association is a not-for-profit electrical cooperative, serving the electrical needs of approximately 115,000 members. Dakota Electric was formed in 1937 by local citizens to provide electricity to the homes, farms, and businesses of Dakota County. Dakota Electric has grown since its founding to be a highly reliable supplier of electricity to members located in Dakota County and portions of Scott, Goodhue, and Rice Counties.

Figure 1 shows Dakota Electric's services within its service territory. Our 500 square mile service territory is located mostly within Dakota County, Minnesota and each of the small green dots represents a member's service.

Figure 1. Dakota Electric's Service Territory



As shown in Figure 1, most of the electric services are concentrated in the suburban portion of Dakota County. This area includes the cities of Apple Valley, Burnsville, Eagan, Lakeville, Farmington, and Rosemount. Except for the service territory around the City of Hastings, much of the remaining service territory is less populated and more rural, similar to Dakota Electric's original service territory characteristics.

As a not-for-profit, member-owned cooperative, Dakota Electric is focused on providing safe, reliable, and economical electrical energy to our members. This member focus drives everything Dakota Electric does as a cooperative. Dakota Electric is the second largest electric distribution cooperative in Minnesota and ranked among the 35 largest electric distribution cooperatives in the nation. Dakota Electric is also the only electric cooperative utility which is rate regulated by the Commission.

Dakota Electric purchases wholesale power and transmission services from Great River Energy (GRE), a generation and transmission (G&T) cooperative, that is headquartered in Maple Grove, Minnesota. The Dakota Electric distribution peak demand has been between 450-500 MW in recent years and occurs in the summer months. This summer peak electrical demand is driven mainly by air conditioning.

In the 1970s, the Minnesota Legislature determined that the orderly development of economical statewide electric service required granting electric utilities exclusive service rights within designated service areas.¹ Because of assigned service territories, the utilities have agreed to supply electricity to anyone obtaining electrical service within their service territory. This is known as the utilities' requirement-to-serve.

While each electric utility has individual requirements and processes for connecting new electrical services, they all have a requirement-to-serve. This requirement-to-serve includes the installation and maintenance of distribution facilities with enough capacity to supply the electrical needs of customers within their assigned service territory. Included in this requirement-to-serve is an expectation that the utility can extend service to new areas within its service territory in an acceptable amount of time.²

The requirement-to-serve drives the utilities to ensure that they not only have sufficient facilities to meet the expected electrical demands of their existing members, but also have options to supply the electrical demands during reasonable expected failures of existing equipment or during periods of maintenance when equipment is required to be out of service. Consumers expect a few short electrical outages due to storms and other events.³ Electrical outages due to insufficient planning, and/or building insufficient facilities, would not be acceptable to the consumers and may be considered a failure to provide safe and reliable service, which is required by Minnesota Statute. The risk of not being able to reliably serve the consumer's electrical requirements is a key issue with incorporating non-wires solutions and other new forms of energy solutions.

c) Highlights of Key Items

i) Reliability

The reliability of the electric service supplied by Dakota Electric ranks us among the most reliable electric utilities in the United States. When comparing Dakota Electric's reliability key indices with other utilities, few perform better. The graph below is from our most recent annual Service Reliability and Service Quality (SRSQ) report filed with the Commission and is a historical look at Dakota Electric's reliability indices.

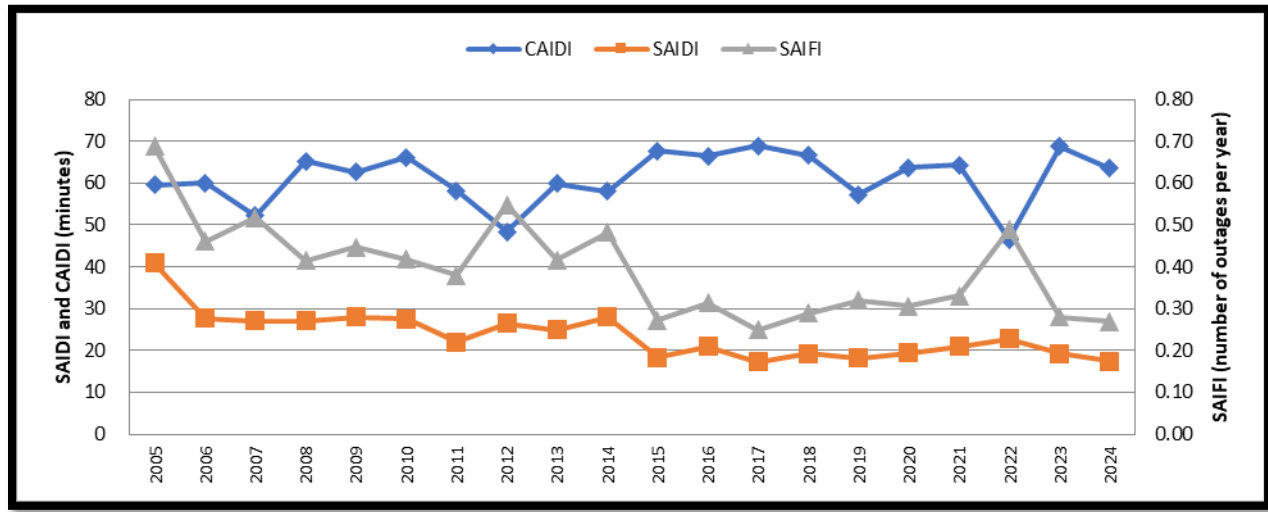
¹ Minnesota Statutes 216B.37 & 216B.39

² This expectation is included in Minnesota Statute 216B.04, which states:

Every public utility shall furnish safe, adequate, efficient, and reasonable service; provided that service shall be deemed adequate if made so within 90 days after a person requests service. Upon application by a public utility, and for good cause shown, the commission may extend the period for not to exceed another 90 days

³ Dakota Electric provides information on customer outages and other service quality related metrics in its annual Service Reliability and Service Quality filing (SRSQ).

Graph 1. Dakota Electric Historical Reliability Indices



The CAIDI, or Customer Average Interruption Duration Index, is a duration index which indicates the average annual minutes per outage for Members that lose power.

The SAIDI, or System Average Interruption Duration Index, is a duration index which indicates the average annual minutes a Member was without power.

The SAIFI, or System Average Interruption Frequency Index, is a frequency index which indicates the average annual number of times an average Member was without power.

In recent years, Dakota Electric’s Board of Directors and the Commission have started using CEMI (Customers Experiencing Multiple Interruptions) to track instances where individual members are experiencing multiple outages per year. Dakota Electric uses CEMI as part of its process of identifying members with a higher number of outages per year. CEMI is a useful metric from an equity standpoint because it is based strictly on the number of outages per member/customer in a year and it is not weighted against revenues, sales, or demand.

Table 1. Dakota Electric CEMI Performance (2022-2024)

YEAR	CEMI ₄	CEMI ₅	CEMI ₆	CEMI ₇
2022	0.54%	0.06%	0.00%	0.00%
2023	0.81%	0.56%	0.16%	0.00%
2024	0.30%	0.05%	0.00%	0.00%

The information in the above table shows Dakota Electric’s CEMI performance since 2022. Overall, Dakota Electric’s data is favorable and, in 2024, it shows that less than one percent, or approximately 360 members, had four separate outages during the years. That being said, Dakota Electric is committed to improving and maintaining these performance metrics because all our members expect, and deserve, the same level of service and reliability.

As discussed above, reliability is a key component of member equity and identifying the causes of outages and characteristics that may contribute to inequities in service are of the upmost importance to a cooperative organization like Dakota Electric. One of the key causes of outages is storms and animals affecting overhead wires and this is especially true when there are trees growing close to the overhead wires. Prior to the 1970s and 1980s,

most residential and business developments were supplied electricity using overhead wires. In the 1980s, many communities in our service territory requested or required utilities to install all new electrical services underground. Based on these policy changes, the newer residential developments in our service territory tend to have underground cables which, on average, have better reliability.

Since older, and rural, areas of our service territory tend to have overhead equipment, we typically find that areas with older homes have the most outages. Beyond the fact that these areas have above ground equipment, the infrastructure (poles, insulators, and wires) was installed at the same time the homes were built and those facilities are aging and naturally become less reliable as the equipment reaches the end of its designed life. In many cases, the older parts of our service territory are also the most affordable and have communities with lower incomes. Unfortunately, since these areas also have a greater percentage of overhead equipment, these are areas of our system that tend to have comparatively lower reliability ratings. Dakota Electric continues to identify pockets of homes experiencing more than normal number of outages, and where economically feasible, identifies projects to move the back lot line overhead wires to underground electrical supply that is more accessible.

In 2024, Dakota Electric worked with the Prairie Island Indian Community to apply for a grant for “Strengthening the Reliability and Resiliency of MN’s Electrical Grid 40101(d)”. This project would enable Dakota Electric to convert the residential services at the Prairie Island Indian community from older overhead service to underground service. Dakota Electric’s application was selected for the grant award; however, the project is unable to proceed at this time due to federal funding uncertainty.

Vegetation is the leading cause of outages on the Dakota Electric system. Prior to 2018, Dakota Electric had no formal documented tree trimming cycle or strategic vegetation management plan. Crews and contractors trimmed/pruned trees to promote tree health, maintain safe clearances from overhead lines, and resolve member tree concerns as resources allowed. Priority was driven by member concerns, safety, and localized reliability concerns. In 2018, Dakota Electric contracted a consulting firm specializing in vegetation management to perform an evaluation of our vegetation management strategy. In 2019, Dakota Electric updated our vegetation right-of-way policy, updated trimming guidelines and clearance diagrams, and aligned our tree contractor agreements with industry best practices. We also updated our internal and external communications, increased our overall vegetation management funding level, and developed a strategic plan to work through member tree concerns and the distribution system trimming to promote safety and resilience to the entire membership. Since 2019, the Cooperative has continued to increase the funding annually to promote and continuously improve overall vegetation management.

Below is a picture of outages on the Dakota Electric system caused by vegetation in 2024. The blue color is a single outage, and the different colors represent areas with more outages with red representing four (4) outages and purple representing five (5) outages. There is a concentration of outages caused by trees in areas in Burnsville and Apple Valley, which are older developments and are supplied by back lot line overhead power lines, and a concentration, in the southeastern portion of the service territory, which is more rural and has many valleys with trees. Outages caused by trees and vegetation is a top outage cause on the Dakota Electric system and is a point of emphasis at the organization. Dakota Electric has embarked on an aggressive vegetation management strategy and is beginning to see improvements in metrics associated with these types of outages. The goal is to continue to reduce the overall impact of outages caused by trees.

Figure 2. Map of Quantity of Outages in 2024 – Caused by Vegetation

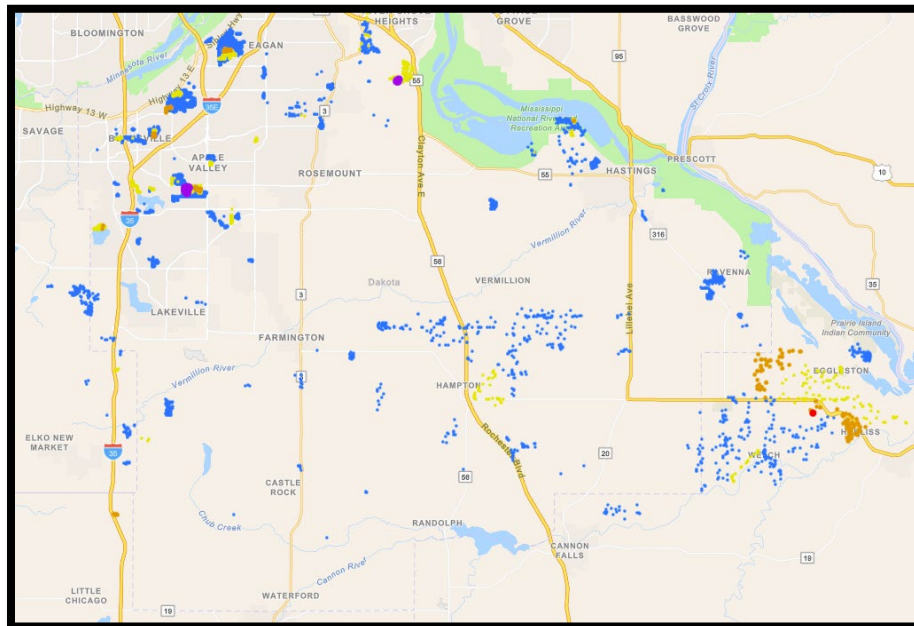
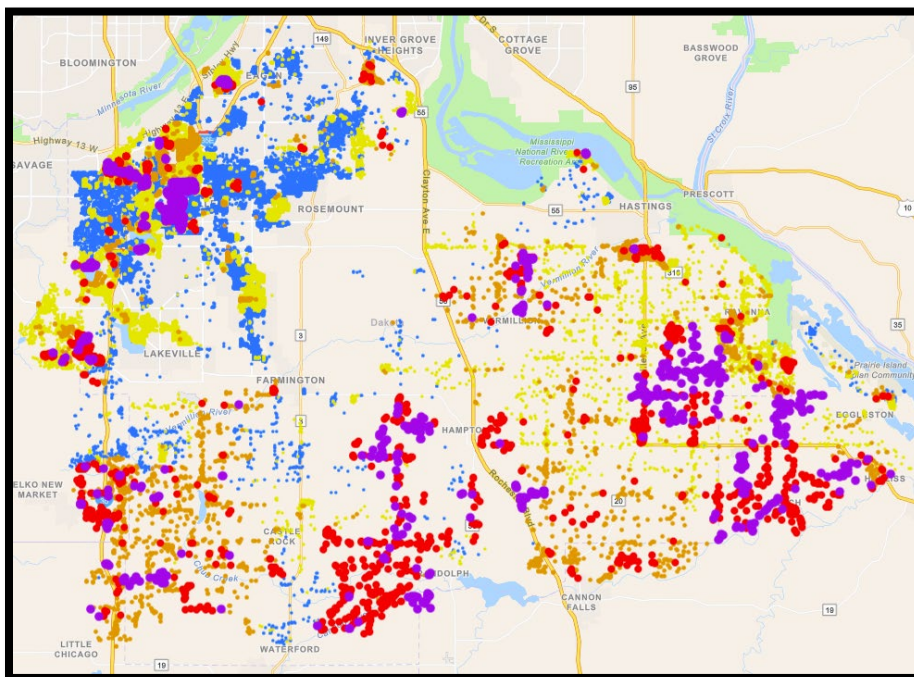


Figure 3. Map of Number of Outages in 2024 – All Causes



Note: The blue color is a single outage, and the different colors represent areas with more outages with red representing 4 outages and purple representing 5 outages.

Overall, the Cooperative seeks to provide a homogeneous reliability experience for all our members. Continuing to identify and improve those portions of the system with the poorest reliability will improve overall reliability performance and help achieve a level reliability experience.

ii) Wildfire Mitigation

Negative impacts from wildfires on a utility system and to the general public have increased in recent years and represent a significant risk to a utility and the general public. Given the characteristics of Dakota Electric's service territory (*e.g.*, largely suburban, high concentration of underground service, minimal forested areas), the overall risk from wildfires is lower than for other utilities, but the Cooperative is mindful of these risks and has implemented, and is considering additional, strategies to further reduce this risk. As discussed in the previous section, the most tangible way Dakota Electric is addressing wildfires is through our vegetation management program. Through our emphasis on vegetation management and a strategy to move toward a standardized right-of-way management program, Dakota Electric is working to reduce the risk of wildfires by identifying and removing trees and other debris that could start a fire if it were to come in contact with energized equipment. In addition, Dakota Electric's extensive use of SCADA and remote monitoring devices provides the Cooperative with visibility into when, and where, outages or potential incidents occur. Dakota Electric is investigating other operational strategies and equipment to determine whether there are additional ways that we can effectively, and efficiently, decrease wildfire risk in our service territory. These devices include remote operated switches, electronic reclosers in lieu of oil filled reclosers, and remote communicating fault indicators. Additionally, Dakota Electric is currently developing a wildfire mitigation plan which likely will include changing reclosing settings on breakers and devices, during times of increased wildfire risks, which will help reduce the likelihood of a wildfire starting if combustible materials were to contact the electrical lines.

iii) AGI Utilization

Dakota Electric has invested in, and received Commission approval for, an Advance Grid Infrastructure (AGI) project which utilizes smart meters with an Advance Metering Infrastructure (AMI) platform, Load Management platform, and a Meter Data Management System (MDM). As part of Dakota Electric's AGI project, the vast majority of the existing meters were replaced with smart meters that communicate through a radio frequency mesh network. Dakota Electric's AMI system and smart meters, including how they work and benefit Dakota Electric, are discussed in more detail in Section 5.d. The meter information then feeds to the MDM system where Dakota Electric can make use of it in various ways such as reports, historical data, and developing scripts to analyze data in new ways that was not previously possible. One example report is line losses. With new smart meters, Dakota Electric can sync the time of member usage at the meter with SCADA and metering information at the substation. Using this data, Dakota Electric can more accurately determine line losses on the grid which allows further insight into troubled areas of the grid and review optimization strategies. Line Losses are discussed in more detail in Section 5.h.

AGI has also allowed Dakota Electric to conduct additional analysis into transformer loading. This transformer analysis tool provides insight into the history of any transformer's load history based on member usage. A user can specify a time period and transformer ID; then the tool will pull all usage data from the meters that are being served from the specified transformer. This allows Dakota Electric to review if a transformer is overloaded or underloaded. Identifying overloaded transformers helps to spot issues before a failure and identifying underloaded transformers can spot areas where we can replace a lightly loaded transformers with a proper sized one and reuse the larger transformer in other areas instead of purchasing new. The following figure shows a sample of the data that can be used to help optimize or determine issues on the grid.

Figure 4. Transformer Analysis Tool



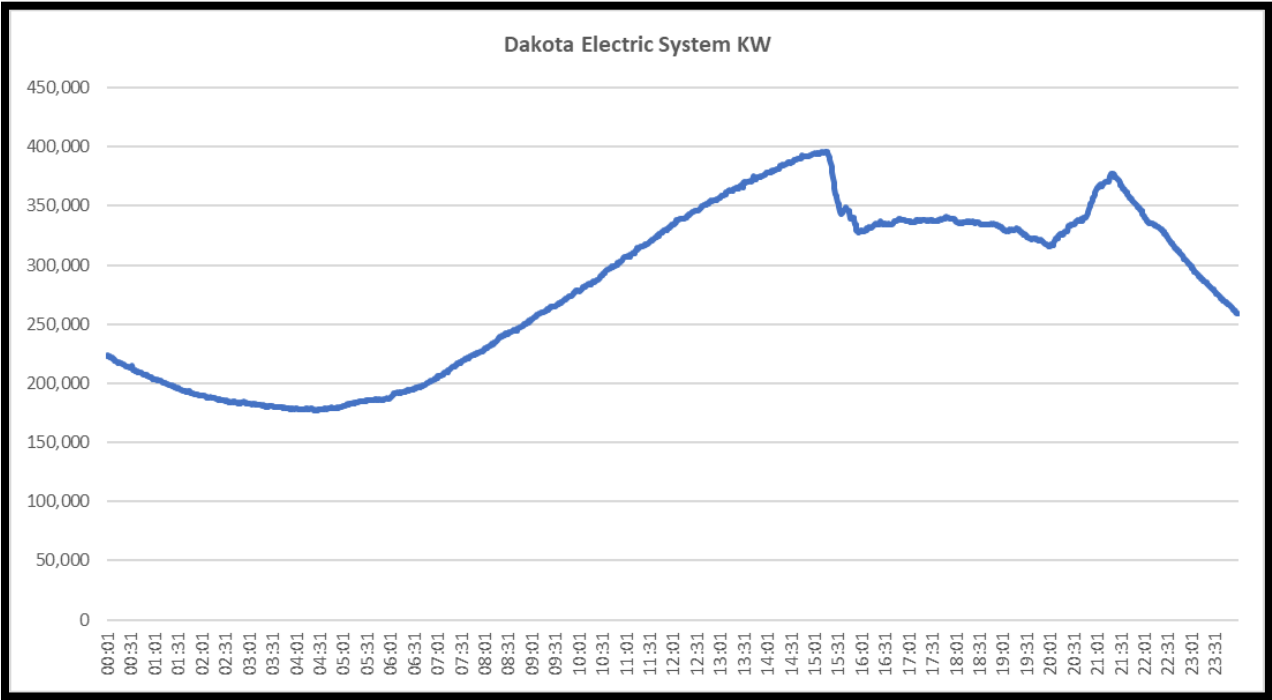
Another tool that the AGi system can offer is Demand Voltage Reduction (DVR). DVR is a grid management strategy used to reduce energy consumption by slightly lowering the voltage supplied to members. This voltage reduction typically occurs during times of peak loading. Since many electrical devices consume less power at lower voltages (within acceptable limits), DVR helps decrease system load without significantly impacting customer service or equipment performance. Dakota Electric has used the AGi to perform tests to determine if DVR is viable on our system. A portion of the smart meters used bring back data every five (5) minutes. This allows the system operators to monitor the voltage at the member level instead of just at substations during these tests to ensure the members are still being provided with adequate voltage. The MDM system was also utilized to perform analysis at the member and service transformer level. Dakota Electric is still developing a DVR program but believes this will be another demand management tool that will be further enabled by the implementation of the AGi system.

Dakota Electric has an extensive demand-side load management system and can control (shed) as much as 100 megawatts (MW) during the summer months and around 70 MW during winter months. Through this demand-side management system, Dakota Electric has a significant amount of load which can be controlled. Dakota Electric is unique among utilities with the ability to control a large percentage (about 20% or more) of its total system demand. Within the IDP report, the demand-side management system may also be referred to as the demand response or load management system. The demand-side management system includes over 40,000 air conditioners and heat-pumps, over 7,000 water heaters, and various other loads under control system. Dakota Electric has installed load control receivers (LCRs) at each of these loads to allow positive control of the loads. As part of Dakota Electric's AGi project, all the existing LCRs were exchanged with new devices. The new LCRs use the same radio frequency mesh network as the AGi meters use to communicate. In addition, some of the businesses have full capacity generation which can disconnect their entire load of the business or the entire business campus and carry that load on their own internal generation system. In support of the member-owned generation installations, Dakota Electric has worked with certain members to create campus micro-grids. The micro-grids isolate a local portion of the Dakota

Electric distribution feeder along with the member’s generation to supply their campus during peak load periods or during weather events. Without this demand-side management system, the Dakota Electric system’s peak electrical demand would be greater, and the power costs charged to our membership would be significantly higher. Dakota Electric, in coordination with Great River Energy (GRE), who is Dakota Electric’s power supplier, operates a load management system to reduce Dakota Electric’s electrical peak demands when GRE’s peak demand is the greatest and likely the costliest. Most of the time this corresponds to when Dakota Electric’s system would have naturally experienced its peak demand. The load management system saves the Dakota Electric membership collectively millions of dollars in wholesale power costs each year.

The following graph shows the total Dakota Electric load curve for a summer load control day in 2024. This day was not our system peak day likely due to the extensive load control and generation which significantly reduced the system peak. This graph clearly illustrates the amount of load control which was achieved on this day. The amount of load which is available to be controlled varies each control day depending upon many factors (*e.g.*, day of the week, the temperature of the proceeding day). This graph illustrates the robustness and importance of Dakota Electric’s load management programs.

Graph 2. Summer Day (June 2024) with Load Management



iv) Increasing Distribution Costs

Distribution costs were noted through review in our pending general rate case as a significant driver of the proposed rate increase. Over the past several years, Dakota Electric, like much of the utility industry, and the general economy, has experienced significant supply chain issues that placed pressure on our general plant, including distribution costs. In addition to supply chain issues, overall demand in the electrical industry placed additional pressure on plant prices. These pressures have resulted in increases to new transformers of over 100% in recent years and increases in new wire of nearly 100%.⁴ Since Dakota Electric has an obligation to serve new members, and

⁴ <https://www.dakotaelectric.com/rates/reasons-for-a-rate-increase/>

maintain its existing system, these are costs that the Cooperative manages but there are minimal mitigation options available. Dakota Electric is mindful of these cost impacts and with increasing demand for electrical service, we are continually evaluating plant costs and potential supplier and equipment options. This continual evaluation includes coordination between Dakota Electric's engineering and purchasing departments which has included visits to new and existing supplier's plants to evaluate alternative sources. Additionally, Dakota Electric's engineering department and purchasing department work extensively together to review new member line extension requests and verify adequate material is procured to ensure minimal delays for our members.

v) Transmission Interconnection Timelines

The fundamental key to the distribution system is its interconnection to the electrical grid, or bulk power system, where it obtains energy. Except in rare, or unique circumstances, the connection to the bulk power system is the foundation that allows a distribution system to provide power to its end use consumers. The point of interconnection between the transmission system and the distribution substation is where responsibility for the flow of energy is transferred from the transmission operator to the distribution operator. A distribution substation provides the conversion from the high voltage transmission (69kV, 115kV, or 161kV) to the medium voltage (12.5kV) local distribution system. The distribution system, as the name implies, is connected to, and supplied by the substation and distributes energy to the local area. The distribution of energy is completed through what are referred to as feeders (circuits). Much like the distribution panel in a home, the distribution substation provides the location where the individual circuits connect with the main source of electrical supply.

Dakota Electric works with Great River Energy to obtain the energy and transmission services required to supply our members with electricity. The two cooperatives work closely together to plan and operate the transmission and distribution systems to ensure safe and reliable energy, with reasonable rates. Engineers from each of the organizations are involved with long-range planning to meet the electrical needs of our membership.

The process to interconnect new distribution substations with the transmission system has been greatly impacted by the volume of new transmission interconnections. Just a few years ago, it was possible to learn about a large new load and obtain a transmission interconnection to supply that new load with electricity within 14-24 months. For interconnections which did not require new transmission lines, the local permitting process was typically the longest lead time and biggest variable within the new distribution substation process. Now, with the significant volume of pending changes to the transmission system (e.g., new distribution substations, retiring existing generation, new transmission lines, interconnection of new generation), the lead times for review and approval of new distribution substations have become very lengthy. The previous 1-2 year process is now a 3-6 year process. These longer planning horizons are illustrated by a local transmission provider requiring 5 years minimum notification to support any new substation interconnection.

Manufacturing facilities and data centers are large loads that have been in the news lately and have expressed interest in Minnesota. When these types of loads express interest in the Dakota Electric service territory, they are asking when they can realistically expect power. Due to current interconnection timelines, Dakota Electric provides these potential loads with longer lead times unless we can realistically serve these prospective loads using existing distribution infrastructure, if the load is requesting service in Dakota Electric's service territory. We continue to work with Great River Energy on this issue, especially because Great River Energy does not own or operate much of the transmission system that Dakota Electric's substations are interconnected to. Dakota Electric is concerned that absent further improvements to the supply chain environment, this will continue to impair the ability of the communities we serve to achieve their economic development goals and, potentially, our ability to swiftly add substation capacity for major electrification efforts.

vi) Future Power Supply Capacity

As noted in the previous section, Dakota Electric is a distribution only utility and relies upon Great River Energy (GRE) for the supply of electricity and the transmission system to get energy to Dakota Electric's distribution system. Over the past few years, Great River Energy has transitioned its power supply portfolio from a primarily fossil fuel baseload portfolio to a generation portfolio based more on renewable energy sources. Great River Energy's electrical supply is forecasted to utilize mostly renewable energy resources and GRE expects full compliance with the State's 2040 Carbon Free Legislation.

As a distribution only utility, Dakota Electric must be acutely aware of changes in its power supply because, even though it has an obligation to serve its end user members, it also has limited abilities to mitigate or manage power supply changes. Although GRE has proactively started transforming its power supply portfolio, as with any change, there are concerns and the potential for unknown outcomes. The transition to more intermittent resources has unknowns associated with it and NERC has voiced concerns recently on the topic. Although these concerns are beyond the scope of a distribution planner, Dakota Electric is responsible for ensuring that there is sufficient physical capacity on the distribution system to deliver that energy, so we attempt to incorporate these concerns into the system and operational plans. While the trends are concerning, Dakota Electric must trust that Great River Energy, and the rest of the utilities which are partners within the Midcontinent Independent System Operator (MISO), are working to ensure the necessary generation capacity is available 24/7 to meet the electric needs of our members. Dakota Electric is confident that Great River Energy, the Commission, and MISO will ensure overall system reliability in Minnesota.

d) Discussion of how IDP meets Commission's Planning Objectives

From the Commission's Notice of Approval of Updated Filing Requirements,⁵ the Commission provided the following IDP report objectives:

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:

- 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;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand Dakota Electric's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of rate payer cost and value.

As a follow-up from the 2023 IDP, changes were made to the filing requirements for 2025 to increase discussion regarding electrification. From Dakota Electric's perspective, the IDP Orders seek information that focuses on the integration of DER and electrification at Dakota Electric in the past, present, and future. Within this IDP report, and already touched upon in this introduction, Dakota Electric provides discussion on topics such as:

- Future modernization plans and capital spending;
- Dakota Electric's forecasted penetration levels for DER systems;

⁵ Docket No. E111/M-25-139, Commission Notice (June 3, 2025).

- A discussion about possible issues which could occur that would affect higher DER levels of integration;
- Impacts from and how Dakota Electric is planning for additional electrification, which includes electric vehicles; and
- Information being learned using Dakota Electric's new AGI metering system.

Dakota Electric crafted its report in a manner that is topic focused, and which aims to answer the filing requirements and questions but also hopes this format is helpful to the Commission and other stakeholders who review this Integrated Distribution Plan. Dakota Electric also would like to note that in the Commission's Nov. 2, 2020 Order (19-674), it was clarified that the review of the IDP is *not* a prudency determination. Dakota Electric sees the IDP strictly as a planning document and an opportunity to educate the Commission and other stakeholders on distribution planning. Dakota Electric encourages stakeholders to ask questions or clarifications but to keep in mind the planning objectives of the Integrated Distribution Plan as set by the Commission.

Dakota Electric has provided a table in Appendix C with locations where the planning objectives are discussed within this IDP.

e) Stakeholder Engagement

As part of the IDP Report development, the Commission encouraged Dakota Electric to engage with its stakeholders. As a cooperative utility, Dakota Electric regularly engages with stakeholders and members to improve processes and operations. Dakota Electric is governed by a 12-person Board, made up of members, which are elected by the membership. The Board provides direct feedback to Dakota Electric staff from the membership. It is also a part of Dakota Electric's normal business practice to engage with its members. This two-way communication between the membership and Dakota Electric staff results in Dakota Electric being naturally, and consciously, responsive to the members.

There were several events which Dakota Electric sponsored over the past year to engage with our stakeholders (members). Many events are aimed at our membership to provide them with information and time to ask questions. Some of the events are aimed at different trades which interact with Dakota Electric to add or modify existing services. Below are summaries of some of these events.

Member Appreciation Event – Minnesota Zoo

Dakota Electric's Member Appreciation Event, hosted annually at the Minnesota Zoo, is a vital platform for enhancing member engagement. The event consistently draws thousands of Dakota Electric members for an evening focused on entertainment and community connections.

In addition to enjoying the zoo, attendees can visit employees at the Dakota Electric booth to receive temporary tattoos and take photos with their family and friends at the co-ops photo booth. The event also highlights the cooperative's electric vehicles, like the Ford All-Electric F-150 Lightning, and provides information on electric vehicle programs and other offerings and services from Dakota Electric. CEO Ryan Hentges and Dakota Electric staff actively participate, addresses attendees, and emphasize the Cooperative's community involvement.

Figure 5. Dakota Electric Member Appreciation Event - Minnesota Zoo



Beyond the entertainment, the Member Appreciation Event underscores the Cooperative's commitment to community involvement. Members regularly contribute non-perishable food items to local food banks and provide monetary support for community organizations, reflecting their ongoing dedication to community well-being. This consistent engagement reinforces Dakota Electric's strong connection with its members, promoting a sense of community and shared values year after year.

Energy Fest

Dakota Electric's Energy Fest is an annual event for its members and the local community. Typically held in September, this expo serves as a platform for exploring the latest developments and innovations in the energy sector. The event saw strong participation with over 300 attendees, 10 dealers offering EV test drives, and 14 vendors sharing information on beneficial electrification and energy-saving practices.

Attendees not only had the chance to test drive various electric vehicles but also engage with EV owners gaining valuable insights from those who have already made the switch to electric. For those curious about electric bikes, the event also provided an opportunity to test ride this equipment.

Figure 6. Dakota Electric Energy Fest



The following is a list of other ways Dakota Electric engages with its membership:

- Apple Valley Music in the Park – Each June, Dakota Electric hosts the Apple Valley Arts Foundation’s Music in the Park.
- Sustainability Commissions - Many of the cities Dakota Electric serves have a sustainability commission focused on achieving specific municipal goals. Dakota Electric had staff present at these commissions and participated in workshops which aim to assist the cities in meeting their goals.
- Solar and Wind Energy Rate options. (Wellspring) – Beyond residential members, businesses and cities have become increasingly interested in powering their facilities with renewable energy. The Wellspring program has been a cost-effective solution to achieve business and municipal goals of offsetting all, or a portion of their carbon emissions. The Wellspring program allows any member, regardless of their service type, to obtain some, or all, of their energy from renewable energy sources. When talking with our membership about this rate option, this is a great chance to get feedback from our membership about renewable energy.
- Greensteps Cities data collection - Many of the cities Dakota Electric serves participate in Minnesota Greensteps Cities.⁶ Dakota Electric supports the cities’ participation in this program through the collection of various pieces of information related to the cities’ sustainability efforts.
- Lakeville Landscape & Home Expo – Each March, Dakota Electric board members and staff participate in the Lakeville Landscape & Home Expo at Lakeville North High School featuring over 100 local vendors including home improvement, landscaping, building, remodeling, windows, siding, flooring, and more.
- Apple Valley Home & Garden Show – Each April, Dakota Electric board members and staff host a vendor booth at the Apple Valley Home and Garden Show. About 2,500 people attend the show, which featured about 90 local businesses.
- Crops Day at Dakota Electric - For the 17th year, Crops Day brought The University of Minnesota and Dakota County Soil & Water Conservation District experts to Dakota County to share local research results and crop management strategies with producers and other agricultural professionals. Crops Day is held each March at Dakota Electric’s headquarters.

⁶ <https://greenstep.pca.state.mn.us/>

- Dakota County Fair – Dakota Electric staff were available to talk with members each day of the Dakota County Fair. This is an excellent opportunity for our members to ask questions and learn ways to save energy. Many questions about appliance selection and energy efficiency are received each year.

Figure 7. Dakota Electric Staff at Dakota County Fair



2) Distributed Energy Resource and Electrification Scenario Analysis

Section C.1. In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER service types, dispersed geographically across the Dakota Electric distribution system in the locations Dakota Electric would reasonably anticipate seeing DER and electrification growth take place first and how the Association would anticipate the combined impacts of simultaneous DER and electrification growth.

Section C.2. Include information on methodologies used to develop the low, medium, and high scenarios, including the DER and electrification adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER and electrification 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.

Section C.3. Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER and electrification 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 and electrification adoption, potential barriers to DER and electrification integration, and the types of system upgrades that may be necessary to accommodate the DER and electrification at the listed penetration levels

With the recent changes to this, and other filing requirements, Dakota Electric believes it is important to have a discussion around ‘Electrification’ and ‘Energy Efficiency’ as was defined in the filing requirements:

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

Energy Efficiency: measures or programs that target consumer behavior, equipment, processes, or devices and are designed to reduce the consumption of electricity on either an absolute or per unit of production basis.

Electrification, as defined, includes all devices such as, but not limited to, electric heating and cooling, electric cooking appliances, and electric vehicles. All these devices converting to electric will have an impact on the distribution system, but Dakota Electric believes specifically, electric vehicles represent the single biggest and most significant concern, and opportunity, for organic load growth to Dakota Electric. The Cooperative reaches this conclusion because electric vehicle's load profile is distinctly unique from the other devices contained in the electrification definition and they represent a completely new alternative "fuel" for the transportation industry and load for the electric industry. Electric vehicles introduce a highly variable, and large, demand profile that varies widely based on user habits, time of day, and location. Other devices included in the definition of electrification, such as electric cooking devices and heating & cooling appliances, do not present as significant as a threat/opportunity to the distribution grid as their demand is not as significant as electric vehicle charging and their timing and demand impacts are much more predictable and better understood. Additionally, these devices have been converting to electric from previous fuel sources for several decades now. Electric vehicles have been around for multiple decades, but the recent technology improvements and popularity growth have been significant.

In 2012, the average usage was 9,843 kWh per Dakota Electric residential member per year. In 2023, the average usage was 9,187 kWh per Dakota Electric residential member per year. Over the past decade, there has been a significant push for increased energy efficiency in devices such as heat pumps, water heaters, electric cooking appliances, and other residential appliances. When considering just lighting, the transition to LED bulbs and fixtures is a serious reduction in demand, a previous 60-watt incandescent bulb can easily be replaced with a 7-10 watt LED bulb. That's almost a 90% reduction in wattage in just a single bulb. This drop in average usage may be counter intuitive when considering the electrification that has occurred over the past decade. Electrification and overall decreases in electricity consumption, at a system level, underscores the complexity of planning for electrification because micro-level or locational impacts of new loads may impact system design while at the same time overall system consumption decreases or remains relatively static.

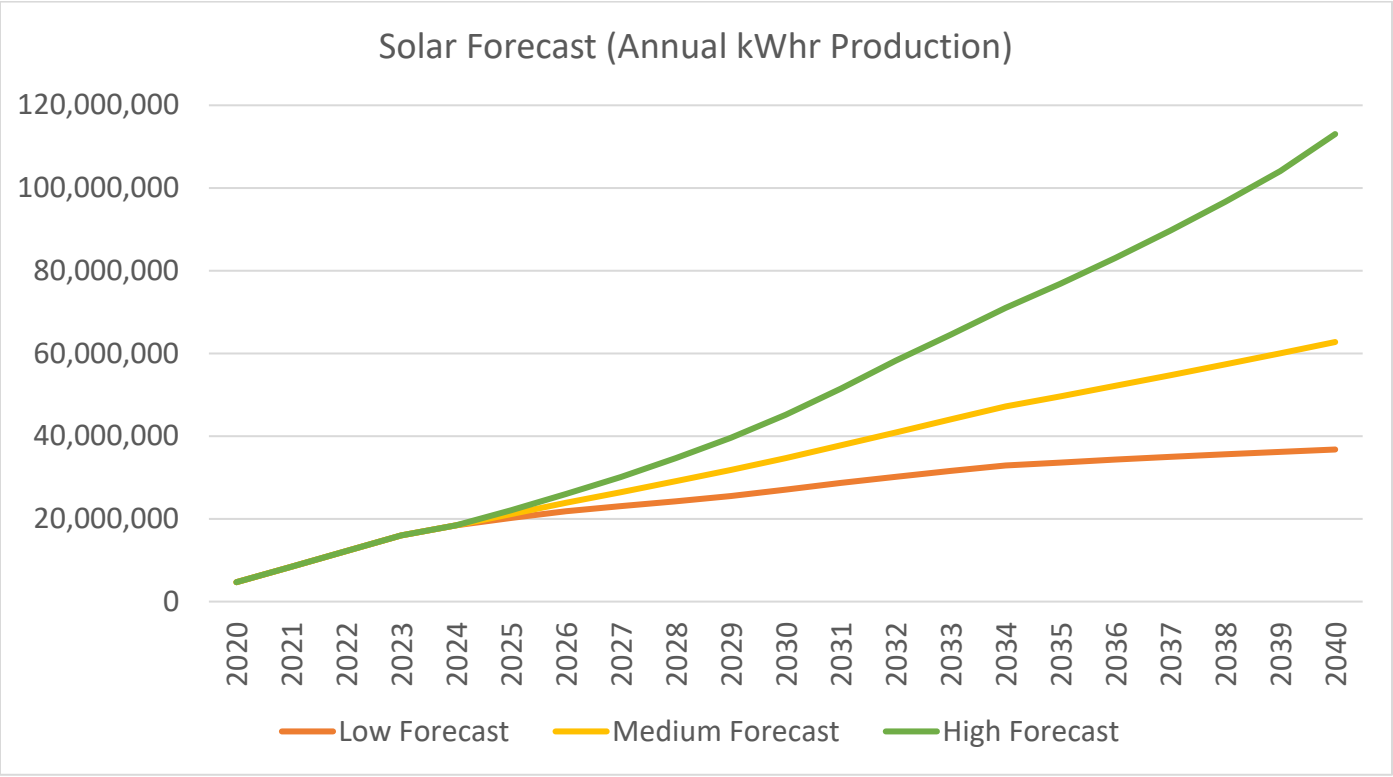
a. Forecast of Member-Owned Solar Interconnections

Over the past two decades, Dakota Electric has gone from a handful of member-owned solar systems interconnected with the distribution system to over 1,500 member-owned solar systems. Most of these member-owned systems have been installed in the past 5 years. While preparing this report, Dakota Electric observed that DER installations on the Dakota Electric system peaked several years ago and have since shown a downward trend in recent years. There may be various reasons for this slowdown, which are discussed below.

As with the 2021 & 2023 IDP solar forecast, Dakota Electric again used the EIA Solar energy growth forecast numbers as the basis for forecasting member-owned solar interconnections. A low, medium, and high forecast were created. Dakota Electric does note that recent legislation related to tax incentives are *not* factored into this forecast as the latest EIA Solar energy growth forecasts. These forecasts were prepared prior to legislative changes. Dakota Electric does believe that the recent legislative changes will have a significant impact on the adoption rate of member-owned solar installations.

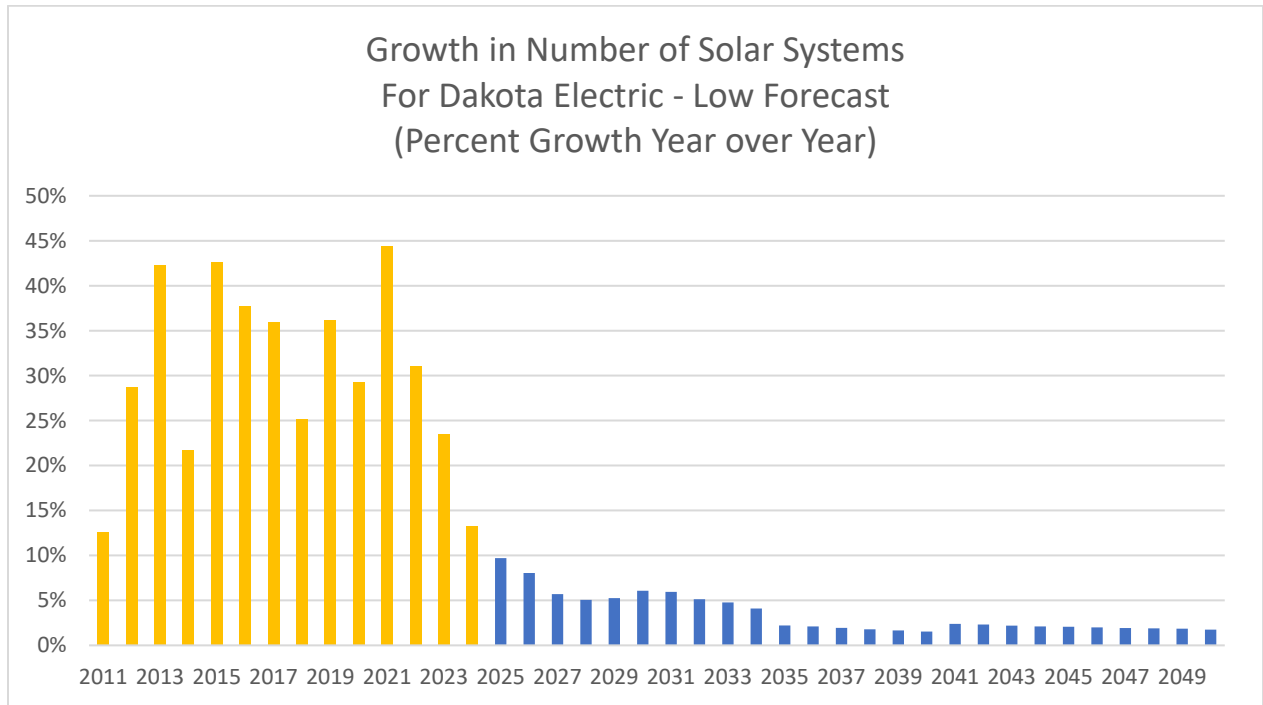
The graph below represents the forecast of total energy generated by the member-owned solar.

Graph 3. Forecast of Total Energy Production - Member-Owned Solar

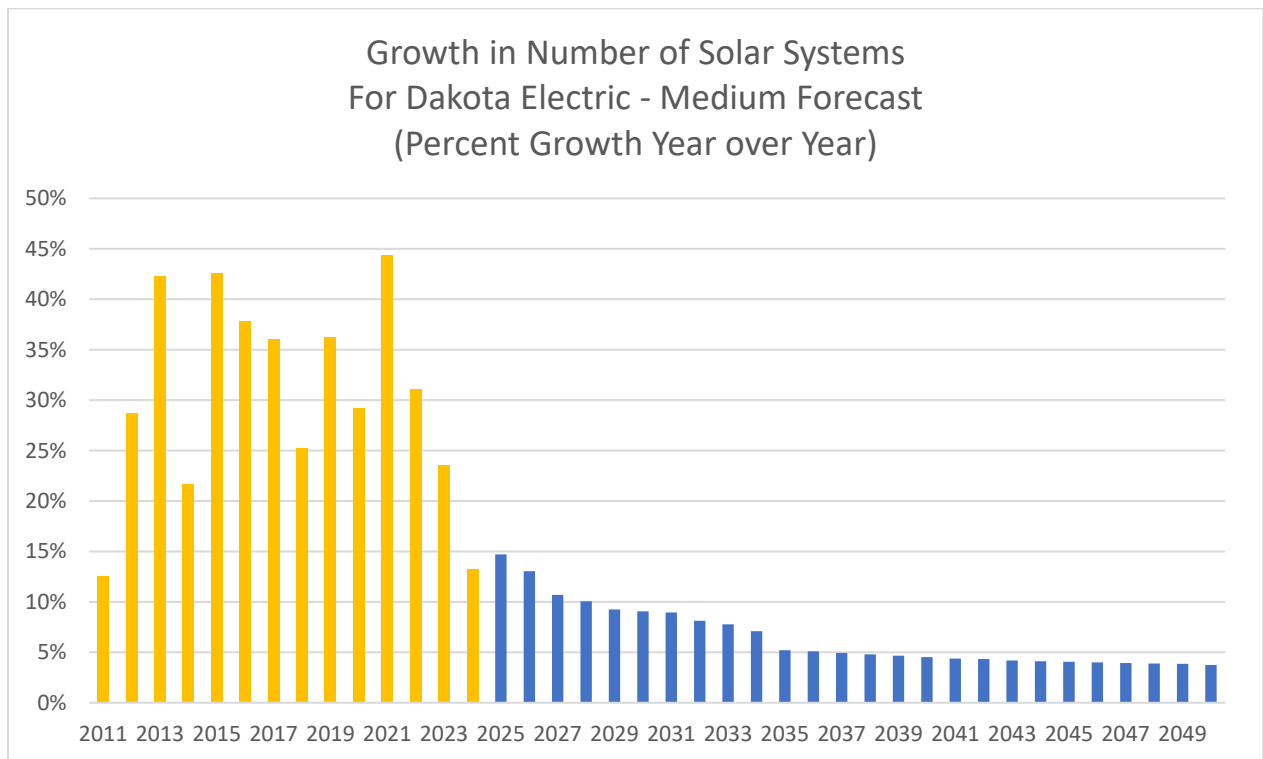


The following graphs show the different annual percentage growth rates for the three levels (Low, Medium, High) of member owned solar forecasts.

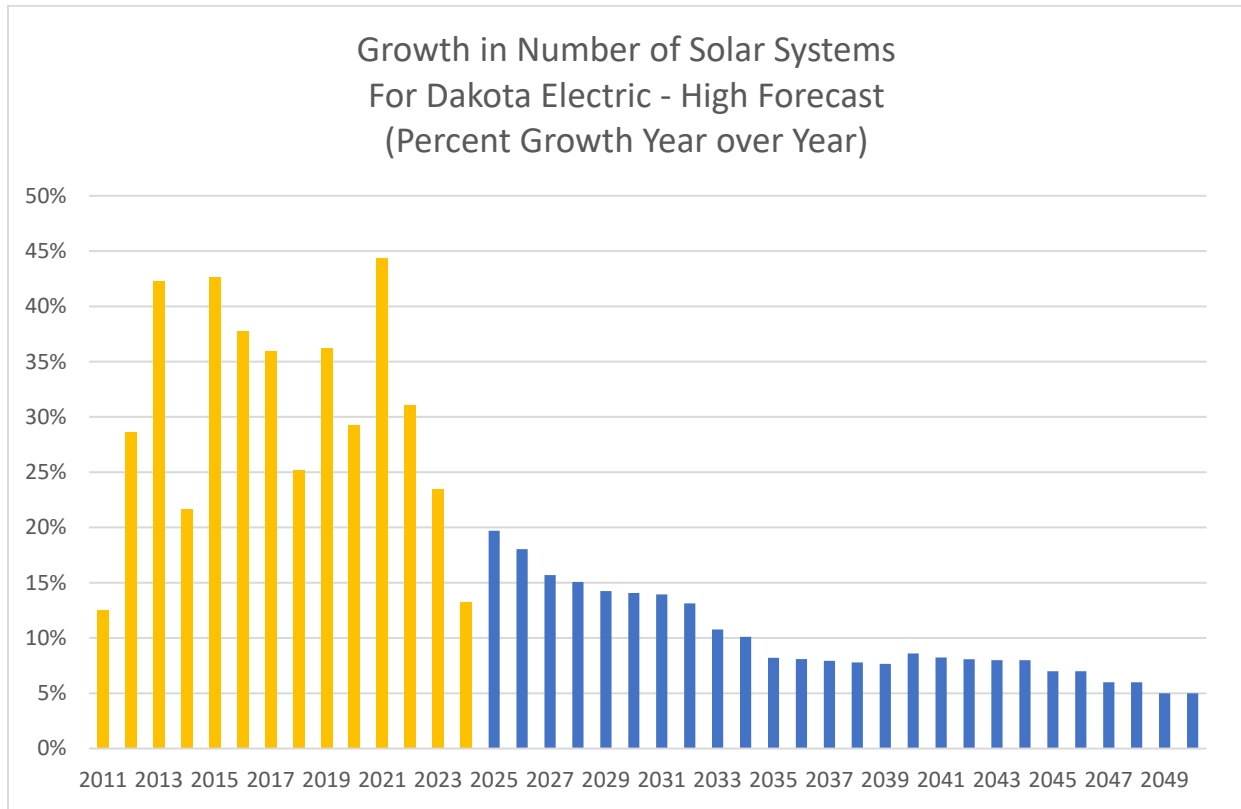
Graph 4. Forecast (Low) Annual % Growth of Member-Owned Solar Systems



Graph 5. Forecast (Medium) Annual % Growth of Member-Owned Solar Systems



Graph 6. Forecast (High) Annual % Growth of Member-Owned Solar Systems



The table below provides the supporting data for the LOW forecast of member-owned solar generation interconnections. The areas in yellow are historical data. The columns include the number of individual installations, the total rated kW of those installations, the expected total energy generated by those installations, and the percent growth over the prior year for the number of new installations.

Table 2. Member Solar - Low Forecast

		Low Forecast	15% capacity factor	
Year	# of Units	Total kW Capacity	Total Solar Energy (kwhr)	% Growth
2006	2	11	14,717	
2007	6	20	26,280	44%
2008	8	28	36,792	29%
2009	14	52	68,446	46%
2010	20	78	102,085	33%
2011	22	89	116,749	13%
2012	26	125	163,685	29%
2013	31	216	283,601	42%
2014	34	276	362,073	22%
2015	54	480	630,937	43%
2016	77	772	1,013,981	38%
2017	118	1206	1,584,139	36%
2018	158	1612	2,117,642	25%
2019	255	2526	3,318,967	36%
2020	393	3570	4,690,620	29%
2021	759	6420	8,436,006	44%
2022	1071	9309	12,232,517	31%
2023	1408	12172	15,994,008	24%
2024	1589	14027	18,431,478	13%
2025	1743	15388	20,220,241	10%
2026	1883	16626	21,846,478	8%
2027	1991	17574	23,091,663	6%
2028	2092	18464	24,261,225	5%
2029	2201	19433	25,535,201	5%
2030	2335	20612	27,084,003	6%
2031	2474	21838	28,695,026	6%
2032	2601	22958	30,166,371	5%
2033	2725	24053	31,605,057	5%
2034	2836	25039	32,900,852	4%
2035	2899	25591	33,626,938	2%
2036	2960	26128	34,332,233	2%
2037	3017	26635	34,997,953	2%
2038	3071	27112	35,625,755	2%
2039	3123	27564	36,219,485	2%
2040	3170	27986	36,773,387	2%
2041	3246	28653	37,650,632	2%
2042	3321	29320	38,526,228	2%
2043	3394	29963	39,370,844	2%
2044	3466	30593	40,199,243	2%
2045	3537	31224	41,028,980	2%
2046	3608	31849	41,849,900	2%
2047	3678	32465	42,658,811	2%
2048	3747	33080	43,467,168	2%
2049	3817	33695	44,274,954	2%
2050	3884	34282	45,046,472	2%

The table below is for the MEDIUM forecast of member-owned solar generation interconnections. The areas in yellow are historical data. The columns include the number of individual installations, the total rated kW of those installations, the expected total energy generated by those installations, and the percentage growth over the prior year for the number of new installations.

Table 3. Member Solar - Medium Forecast

	Medium Forecast		15% capacity factor	
Year	# of Units	Total kW Capacity	Total Solar Energy (kwhr)	% Growth
2006	2	11	14,717	
2007	6	20	26,280	44%
2008	8	28	36,792	29%
2009	14	52	68,446	46%
2010	20	78	102,085	33%
2011	22	89	116,749	13%
2012	26	125	163,685	29%
2013	31	216	283,601	42%
2014	34	276	362,073	22%
2015	54	480	630,937	43%
2016	77	772	1,013,981	38%
2017	118	1206	1,584,139	36%
2018	158	1612	2,117,642	25%
2019	255	2526	3,318,967	36%
2020	393	3570	4,690,620	29%
2021	759	6420	8,436,006	44%
2022	1071	9309	12,232,517	31%
2023	1408	12172	15,994,008	24%
2024	1589	14027	18,431,478	13%
2025	1823	16090	21,141,815	15%
2026	2060	18188	23,899,261	13%
2027	2281	20134	26,456,412	11%
2028	2510	22161	29,119,214	10%
2029	2743	24211	31,813,057	9%
2030	2991	26406	34,697,024	9%
2031	3259	28768	37,801,799	9%
2032	3524	31107	40,874,150	8%
2033	3798	33523	44,049,733	8%
2034	4067	35904	47,177,247	7%
2035	4279	37773	49,633,716	5%
2036	4497	39698	52,163,749	5%
2037	4719	41659	54,740,144	5%
2038	4945	43656	57,364,291	5%
2039	5176	45693	60,041,238	5%
2040	5411	47763	62,760,683	5%
2041	5648	49858	65,513,079	4%
2042	5892	52014	68,346,901	4%
2043	6139	54195	71,212,218	4%
2044	6391	56419	74,134,833	4%
2045	6651	58712	77,147,718	4%
2046	6917	61061	80,234,267	4%
2047	7189	63463	83,389,790	4%
2048	7469	65934	86,637,768	4%
2049	7757	68478	89,980,585	4%
2050	8048	71041	93,348,162	4%

The table below is for the HIGH forecast of member-owned solar generation interconnections. The areas in yellow are historical data. The columns include the number of individual installations, the total rated kW of those installations, the expected total energy generated by those installations, and the percentage growth over the prior year for the number of new installations.

Table 4. Member Solar - High Forecast

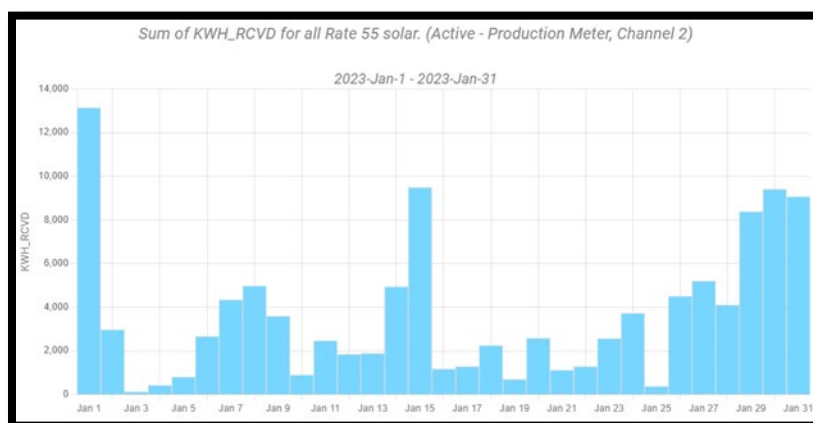
Year	# of Units	High Forecast	15% capacity factor	% Growth
		Total kW Capacity	Total Solar Energy (kwhr)	
2006	2	11	14,717	
2007	6	20	26,280	44%
2008	8	28	36,792	29%
2009	14	52	68,446	46%
2010	20	78	102,085	33%
2011	22	89	116,749	13%
2012	26	125	163,685	29%
2013	31	216	283,601	42%
2014	34	276	362,073	22%
2015	54	480	630,937	43%
2016	77	772	1,013,981	38%
2017	118	1206	1,584,139	36%
2018	158	1612	2,117,642	25%
2019	255	2526	3,318,967	36%
2020	393	3570	4,690,620	29%
2021	759	6420	8,436,006	44%
2022	1071	9309	12,232,517	31%
2023	1408	12172	15,994,008	24%
2024	1589	14027	18,431,478	13%
2025	1902	16791	22,063,389	20%
2026	2245	19821	26,044,202	18%
2027	2598	22932	30,133,065	16%
2028	2989	26387	34,672,571	15%
2029	3415	30147	39,613,787	14%
2030	3896	34388	45,185,609	14%
2031	4439	39184	51,488,208	14%
2032	5022	44328	58,247,336	13%
2033	5562	49102	64,520,092	11%
2034	6124	54061	71,036,597	10%
2035	6627	58498	76,866,493	8%
2036	7163	63235	83,090,688	8%
2037	7732	68255	89,687,300	8%
2038	8335	73575	96,677,372	8%
2039	8974	79216	104,089,215	8%
2040	9746	86032	113,046,279	9%
2041	10548	93115	122,352,689	8%
2042	11400	100633	132,231,381	8%
2043	12312	108683	142,809,891	8%
2044	13297	117378	154,234,682	8%
2045	14228	125594	165,031,110	7%
2046	15223	134386	176,583,288	7%
2047	16137	142449	187,178,285	6%
2048	17105	150996	198,408,982	6%
2049	17960	158546	208,329,431	5%
2050	18858	166473	218,745,903	5%

b. Impact of DER on Dakota Electric Peak Demands

With the variable nature of DER generation, the energy output cannot be counted upon to be available 100% of the time to offset an individual member's electrical demand. Therefore, it cannot be assumed the DER will be providing energy coincident with peak loads, which are the events that Dakota Electric plans for when conducting distribution system studies. As the amount of DER systems increases, Dakota Electric will need to develop 8,760-hour modeling of the distribution system and incorporate data from the AGI system's advanced meters within that modeling. Dakota Electric will also need to implement an Advanced Distribution Management System (ADMS) with real-time modeling to support engineering analysis and to provide a tool for its system operators. This additional data and system functionality will be required to support the day-to-day operation of the system as the multitude of possible system modes of operation (given the variable load, variable generation, and variable distribution system configurations). Thus, a robust, real-time model will be required to provide the system operators with visibility of what is occurring on the system. This real-time view of the distribution system can also be used by the engineers to identify potential contingency issues and help them plan a robust, reliable, and resilient distribution system.

The current expectation is that as the overall level of DER penetration increases, the aggregate output from many DER generators will provide a reliable partial reduction in electrical demand at the substation level. Dakota Electric has been using its AGI metering data to see if the aggregated output from solar DER systems does provide a reliable level of energy to support the distribution system.

Graph 7. Solar DER Output January 2023 – Production Meters



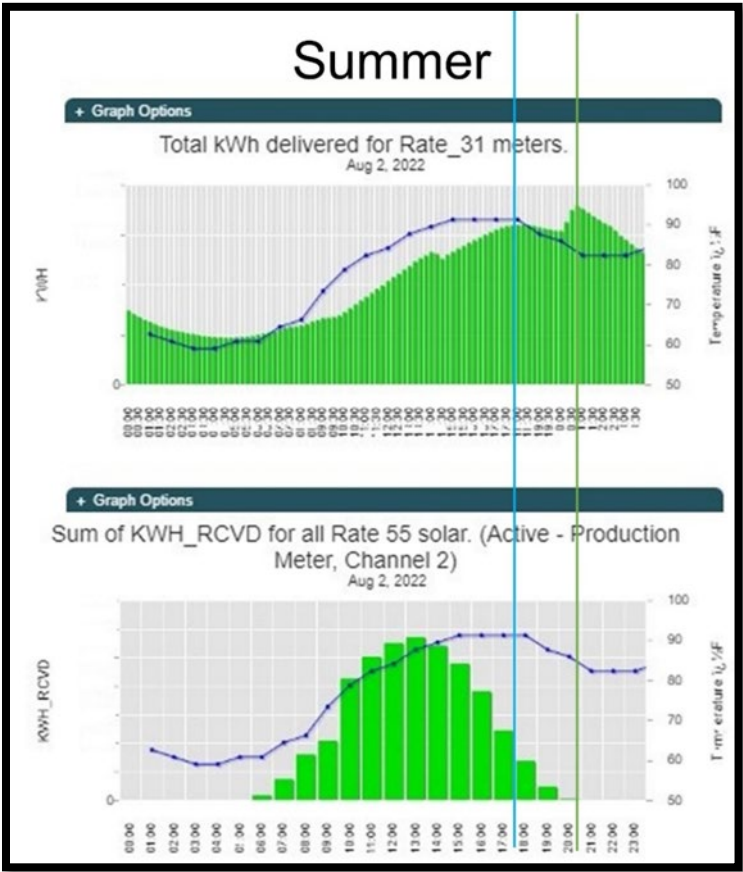
Thus far, the data captured above shows that even with many aggregated solar installations, there is a common loss of output due to snow cover in the winter, cloud cover in the summer, and other environmental related conditions. The variability of solar output can be seen in the above graph from January 2023. This graph represents over 1,000 individual solar installations on member homes, which are located across the Dakota Electric distribution system.

Dakota Electric uses demand side management/load control to reduce billing peak demands. Working in conjunction with Great River Energy, our wholesale power supplier, there are many programs developed to provide our members with options to reduce their cost of energy. In terms of DER systems, such as member owned solar, these systems are generating little or no energy during periods of distribution system peak demands.

Below are two graphs, the top graph shows the total load curve for all the residential members on the Dakota Electric system, and the second graph is the sum of all the energy produced by the member owned solar systems. The top graph is a hot summer day where load control was implemented to reduce the peak demand. That load graph shows the dip in the demand, starting around 2 pm when load control began, and restoration occurring

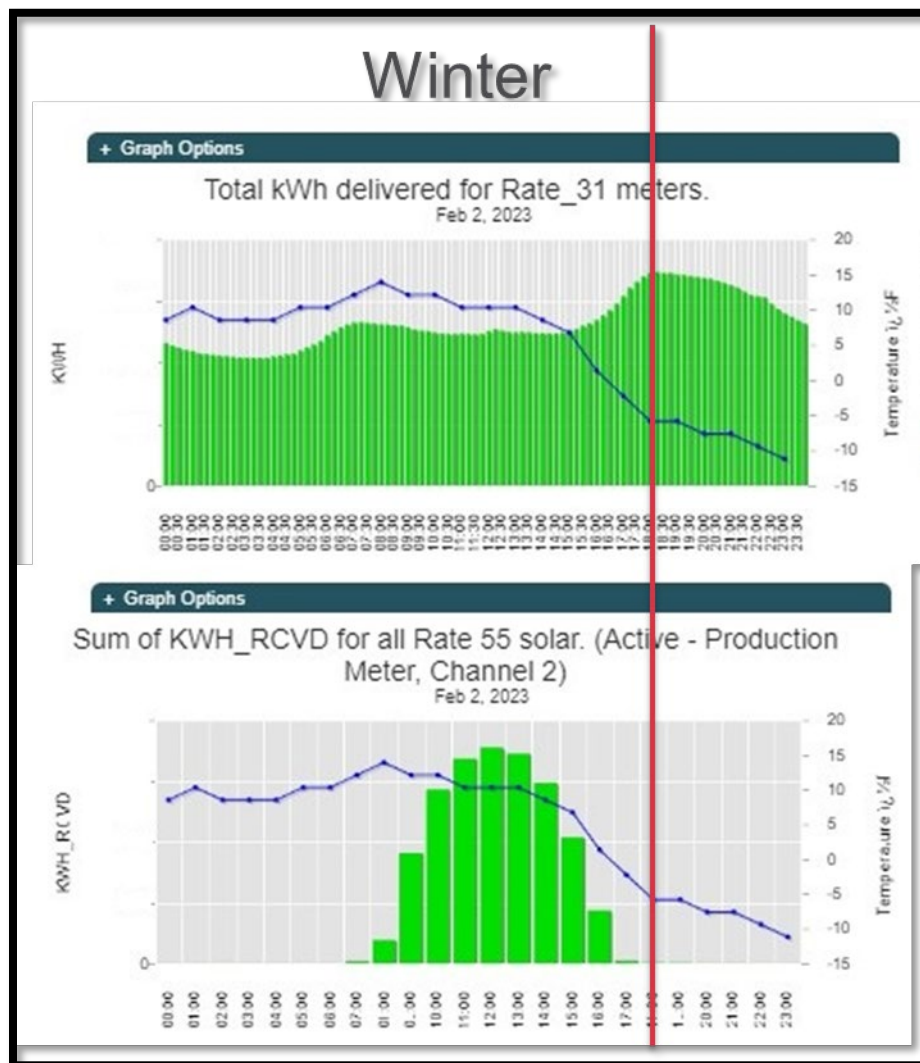
around 8:30 pm when load control was lifted. In the bottom graph, the blue line coincides with when the distribution peak would have been without load control, and the green line coincides with the actual distribution peak demand. Unfortunately, the solar output at the time of the normal peak demand (blue line) is minimal and at the time of the actual peak demand there is no production.

Figure 8. Solar Summer Production During Distribution System Demand



The next two graphs show the same relationship but during a winter peak day. During a typical winter peak, the peak load occurs after the sun has set and no energy is being produced by the solar system (red line) to help support the distribution system.

Figure 9. Solar Winter Production During Distribution System Demand



During the summer months, there is a small amount of energy being produced by the member-owned solar which can help offset a member's peak load. During the rest of the year, there is little support provided by member-owned solar coincident with their peak demand.

c. Planning & Tools to Accommodate DER

On June 7, 2023, the Commission issued an Order in Docket No. E999/CI-20-800 adopting Dakota Electric's internal DER screening tool and requiring Dakota Electric, Otter Tail Power, and Minnesota Power to provide information and discussion in the 2023 IDP Report about providing discrete interconnection data to developers. Ordering Point No. 1 stated:

The Commission adopts and applies to Dakota Electric Association, Otter Tail Power, and Minnesota Power, the Dakota Electric Association proposal outlined in its June 30, 2021 Reply Comment to provide discrete sets of information on-demand, in the context of other existing DER interconnection tools and improvements being considered to maintain an orderly, efficient, and cost-effective deployment of DER in Minnesota. Utilities implementing this process shall make a

compliance filing, to be filed with their IDPs, providing a narrative report on their implementation of this policy.

As discussed in Docket No. E999/CI-20-800 and previous IDP reports, Dakota Electric developed a tool within our GIS to allow our engineering department to quickly review the remaining capacity of the distribution system to support additional DER interconnection. This tool is used internally to review DER interconnection applications. Given a specific existing service on the distribution system, the GIS tool scans the distribution system upstream of the service and reports the remaining capacity of each of the facilities to support new DER interconnections. As the tool scans the circuit upstream within the GIS, it identifies all the devices in the path back to the substation. At each device along the circuit, the tool records the device rating and then it adds up the total DER kW capacity of all existing and approved downstream DER systems. The tool then has the device rating and the total DER capacity which could back feed that device. For multi-phase devices, Dakota Electric's analysis is completed on a per phase basis as most of the interconnected DER systems are single phase. The tool then calculates the percentage of the device's rating (capacity) which is already "reserved" for the existing DER downstream of that device. The tool currently does the capacity analysis to see if there is spare capacity on each device for the new DER interconnection. The tool does not currently conduct any voltage analysis. Overall, this tool allows engineering staff to review and quickly identify conflicts between the proposed new DER interconnection and existing DER.

The figure below presents an example of the study results. In this example, the transformer supplying the home studied is TRN22395, and it is a 37.5 kVA transformer. There are 19 kW of existing DER interconnected at homes which are also supplied by this same transformer; as such, the existing transformer is about 50% loaded with interconnected DER. Tracing further upstream on the electrical circuit, the program finds a fuse (FUS11974). This is a 100E fuse which has a capacity of 720 kW. There is 25kW of existing DER already connected to this fuse on the same phase. The fuse is around 3% loaded with existing DER. This is a simple, and effective, screening tool for the engineer who is reviewing applications.

Figure 10. Results from GIS Hosting Capacity Tool

FacilityID	Length (ft)	Size	Phase	Rating (amps)	Total Capacity (kW)	Existing DER (kW)	Available Capacity (kW)	Loading (%)
	64	2/0 Triplex	A					
	67	4/0 Triplex	A					
	132	350 MCM Triplex	A					
TRN22395		37.5	A	0	37.5	19	18.5	50.67
	1644	#2 URD	A					
FUS11974		100E	ABC	100	720	25	695	3.47
	1915	500 MCM URD	ABC					
	3967	750 MCM URD	ABC					
BRK25FB06		600	ABC	600	4320	57.44	4262.56	1.33

Given the low penetration of DER on the Dakota Electric system, this tool is working well and allows quick review of a DER interconnection application. As members contact Dakota Electric, this tool enables Dakota Electric engineers to easily review capacity issues with their potential DER interconnection.

With the Commission directing the Distribution Generation Working Group (DGWG) to investigate how battery storage systems should be evaluated under the MN DIP,⁷ Dakota Electric expects direction from the DGWG to help shape how to continue to improve this internal screening tool in the future. Additionally, with future grid modernization projects, Dakota Electric believes the AGI project allows more visibility into our system and, combining with a future ADMS system, will provide additional tools that will likely be required to operate a significant amount of increased DER on the distribution grid.

d. Discussion on Potential Barriers to DER Interconnection

Dakota Electric provides discussion on two potential barriers to DER interconnection below. Although these barriers have been identified, there may be other barriers that have not been identified yet.

i) MISO Transmission Injection Requirements

MISO has created a process for reviewing the injection of energy into the transmission system due to back-feeding caused by distribution interconnected DER. MISO has worked to develop a consistent set of rules and processes for when and how injections (back feeding) from distribution substations are studied and approved. The goal was to create a set of rules which are applied to all DER interconnections and a clear process for how these injections are studied and approved.

New distribution DER interconnections will be impacted once there are sufficient levels of DER interconnected to a substation to cause back feeding into the transmission system. Once this back feeding level is reached, this new MISO process will affect the interconnection of additional DER to the distribution system supplied by that substation. The impacts will include the costs of the required transmission studies and the lead times required for the study process to be completed.

Long transmission study lead times are the result of the large volume of proposed transmission changes. These transmission changes include new transmission lines, new transmission level DER interconnections, removal/retirement of existing base load generators, additions of new loads and the resulting new distribution substations, and injection studies in support of distribution interconnected DER. All these proposed changes require detailed studies and analyses. Transmission studies are complex and lengthy as the engineers must study all potential operating modes of the transmission network. They must look at many different variables, such as: generation configurations and output levels, varying levels of energy exchange among the utilities, different seasonal load levels, and contingencies involving loss of individual transmission components. In most cases, there are thousands of different probable operational combinations for these independent factors. From just new DER interconnections, MISO is reporting significant growth in requests for new transmission level interconnections. All these proposed changes impact the flow of energy on the transmission system and, given the very tight physical constraints which the transmission system is required to operate in, the study and analysis process is not simple. Many of these studies, for a given region, cannot be done in parallel due to the interactions among modifications to the transmission system. Thus, the available staff and systems used to study and analyze these changes are overwhelmed and the queue is long.

As part of the new transmission injection rules, MISO will require screening for any proposed back feeding to the transmission system. There are several possible screens which may apply depending upon the magnitude of the

⁷ Docket No. E999/CI-16-521, Commission Order (April 15, 2024).

expected transmission injection. The first screening will be performed by the area transmission utility, with subsequent screens to be performed by MISO. For Dakota Electric, Great River Energy is the transmission service provider, and the majority of Dakota Electric's distribution system is in the Xcel Energy transmission area. The load level used for screening varies by generation type, but, for solar, summer peak loading will be used. Using these assumptions, "DER Net Injection" will be determined by subtracting the nameplate capacity of all existing and proposed DER at a substation from the native minimum load level.

The purpose of the first screen is to identify if the "DER Net Injection" will exceed 1MW. If "Net DER Injection" remains below 1MW, then no formal "MISO DER Affected System Study (AFS)" will be required. The AFS threshold was recently changed from 0MW to 1MW of "DER Net Injection." The assumption is that these existing processes could adequately capture impacts of smaller DER Net Injections in shorter timeframes, and at lower cost; whereas, MISO is better suited to study impacts and allocate upgrade costs as the "DER Net Injection" increases. Under the new process, the area transmission utility may still require a Transmission System Impact Study (TSIS) to identify local reliability issues that would otherwise not be captured. Great River Energy does require a transmission study for any aggregation of existing and proposed DER that exceeds the daytime minimum load at a substation. Great River Energy requires a study downpayment of \$10,000. If the actual cost for the study is less than the downpayment, the excess funds are returned.

The second screen, which is part of the same local transmission utility study noted above, is undertaken for a proposed DER if the existing DER, along with the proposed DER, will not exceed 5MW of new injection onto the transmission. The second screen will determine if the proposed DER causes a greater than 1% change in utilization of a transmission facility. For example, if a DER with 3MW of "DER Net Injection" caused the flow on a 100MVA transmission line to change from the current 40MVA to 42MVA, under normal operating conditions, the proposed DER would fail the second screen due to a 2% change in transmission facility utilization. As a result of failing the second screen, a MISO DER AFS would be required.

The final screen is triggered if existing DER plus the proposed DER has greater than 5MW of "DER Net Injection" to the transmission system or if the proposed DER fails the second screen. Once the 5MW threshold is reached, it automatically requires a MISO DER AFS. The deposit for the MISO transmission study is expensive and requires a \$60,000 study downpayment. MISO has indicated the potential to adjust this deposit amount after determining actual costs from the first cycle of studies. The MISO transmission studies are run in batches and on a fixed schedule. To be included in the next round of MISO studies, a formal application and study downpayment is required to be submitted by a specific time frame. Missing this deadline results in the application being delayed until the next study period.

It is important to note that once a substation, has been studied and approved for "DER Net Injection" into the transmission system, each time an aggregation of additional DER exceeding 1MW is proposed, there will be a new MISO DER AFS required along with a new \$60,000 study deposit. As the amount of DER which is interconnected to the local distribution system reaches the level where the output of the DER exceeds the native load on the distribution system, the required transmission studies will impact the DER interconnection costs and application approval timeframes. It will also increase the chance that DER interconnections will trigger transmission studies. Currently, the costs for completing these transmission studies will be incurred by each of the DER systems which are causing additional transmission injections.

An issue faced by the local distribution utility with transmission injection is if there is a loss of native load on a substation that results in injection of energy into the transmission system. The MN DIP interconnection review process assumption is that new DER systems, which are interconnected to the distribution system, are approved without any transmission studies, because the existing native load on the distribution system is greater than the

output of all the interconnected DER. As the number of DER systems interconnected to the distribution system increases, eventually the output of all DER may be greater than the existing native electrical load and the excess energy generated by the DER must flow into the transmission system. The problem with this study assumption is that the existing electrical loads are not static and will vary over time. As more DER is added to homes and businesses, the existing load is naturally reduced. As energy efficient appliances and LED lights replace older appliances and lights, the electrical load level is also reduced. It is also important to consider an impactful potential change which occurs when an area business closes or significantly reduces its load and there is a large loss of native electrical load on the substation. Over time, with energy efficiency or immediately after a large loss of load, injections from distribution interconnected DER can cause unplanned and unapproved injections onto the transmission system.

This type of scenario is best illustrated by examining the feeder minimum loading levels for the substation River Hills West, as reported in Appendix A. The minimum load at this substation has decreased over the past few years; in particular, the daytime minimum load has decreased since 2020 (highlighted in blue).

Figure 11. Example of Negative Load Growth in Feeder and Substation Minimum Loads

Feeder Minimum Loading Levels										
Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
River Hills West (9)	Substation	10,919	11,824	11,849	2,536	2,601	2,644	3,098	3,421	3,471
	1				410	478	298	676	478	756
	5				721	775	653	721	1,033	653
	6				720	708	756	1,047	919	1,051
	7				383	411	12	529	533	117

If transmission injection occurs, and is above existing approved injection levels, the local distribution utility is required to reduce the injections to a level below the approved amount. If this back feeding occurs without warning, the utility may be required to immediately curtail existing interconnected DER output or find a way to quickly add more load to the existing substation to offset the DER output. After any surprise occurrence, or if there are longer term trends for loss of load, the utility will need to review the probability of future transmission injections from that substation. If the future injections are probable, then the utility will be required to: pay for transmission studies to obtain approval for those future injections, pay for required transmission upgrades, or develop run back or curtailment schemes with the existing DER systems. In anticipation of these possibilities, distribution utilities will need to develop methods and procedures to deal with this future issue and not allow unapproved back-feeding of the transmission system.

ii) Residential Solar Installation Costs

Another potential barrier to DER Interconnection is the average cost of residential solar installations. When submitting applications, installers are asked to provide total installation cost without any incentives. A chart with the average price per watt of installed solar is shown below. This data was obtained from Dakota Electric’s annual Distributed Energy Resource (DER) Interconnection Report⁸ and includes only residential solar application costs.

⁸ Docket No. E-999/CI-16-521. Dakota Electric Distributed Energy Resource Interconnection Process Filing (March 3, 2025).

Table 5. 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

From the table above, there is a trend from 2018-2023 of steadily increasing price per watt of installed distributed solar capacity. Dakota Electric is unsure of the exact reasons for the price increases but the COVID-19 pandemic and affects to supply chain were likely drivers. In 2024, there was almost a full \$1 drop in the price per watt which may mean that the supply chain is recovering. Dakota Electric also notes a declining trend in residential solar applications since 2021. The significant decrease in applications in 2024 was likely driven, in part, by increases in interest rates which negatively impacted the economics of solar facilities. The Cooperative also notes that recent tax changes may put further downward pressure on DER interconnections as tax incentives expire.

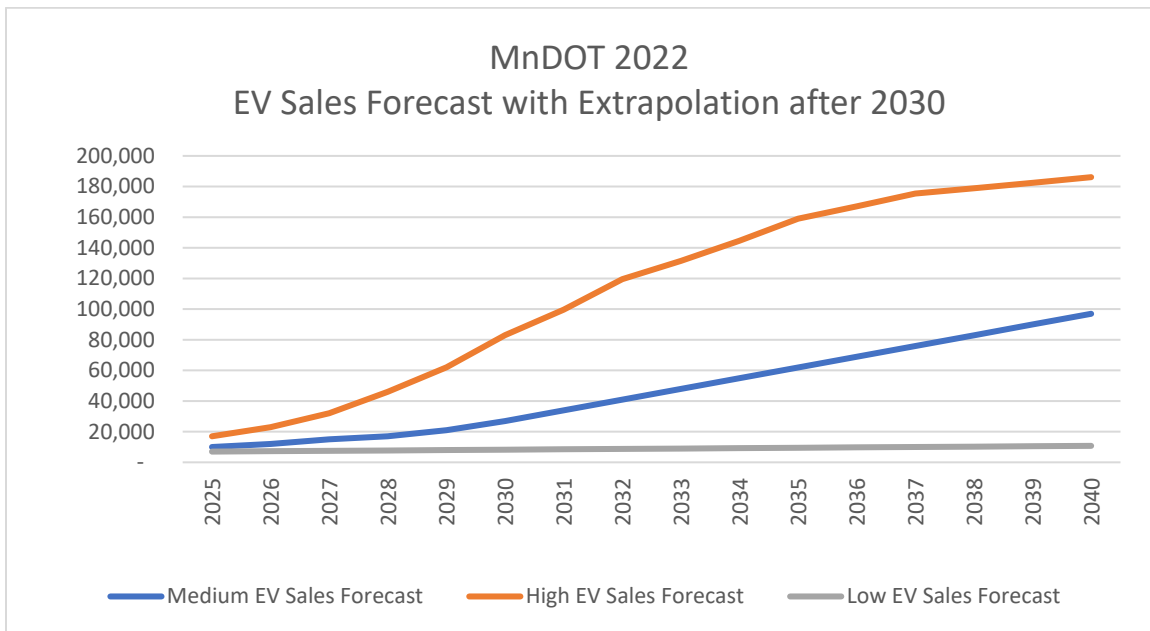
a. Forecast of Electric Vehicles

The bulk of the EV sales in Minnesota have occurred in and around the Twin Cities metro area, which includes Dakota Electric's service territory. As a result, Dakota Electric has experienced many members purchasing EVs. There are several forecasts available for how many EVs there will be in Minnesota over the next few years. Since there are significant differences between EV adoption rates across Minnesota, a more detailed forecast for Dakota Electric's service territory is required. In just the past 7 years (2018-2024), Dakota Electric has seen the number of EVs on our off-peak programs grow significantly. Specifically, from 2022 to 2024, the Cooperative saw the cumulative EVs on an Off-peak program grow from 941 to 1,876 EVs, which is almost double.

The following EV forecast for the Dakota Electric service territory was created using the growth rates in the MnDOT EV forecast based provided in the 2022 MnDOT Electric Vehicle Infrastructure Plan.⁹ The MnDOT forecast provided EV sales numbers up to 2030. This forecast was then extrapolated through 2040. Below is a graph showing the Low, Medium, and High EV sales forecast. The High forecast was tapered off due to the number of annual sales of passage and light duty vehicles reaching 100% of all sales. Dakota Electric notes that recent federal tax incentive changes are *not* considered in these forecasts as the data was prepared prior to the legislative changes. Dakota Electric believes there will be an impact on the adoption rate of electric vehicles due to legislative changes but also believes electric vehicle growth will continue to be strong over the next decade.

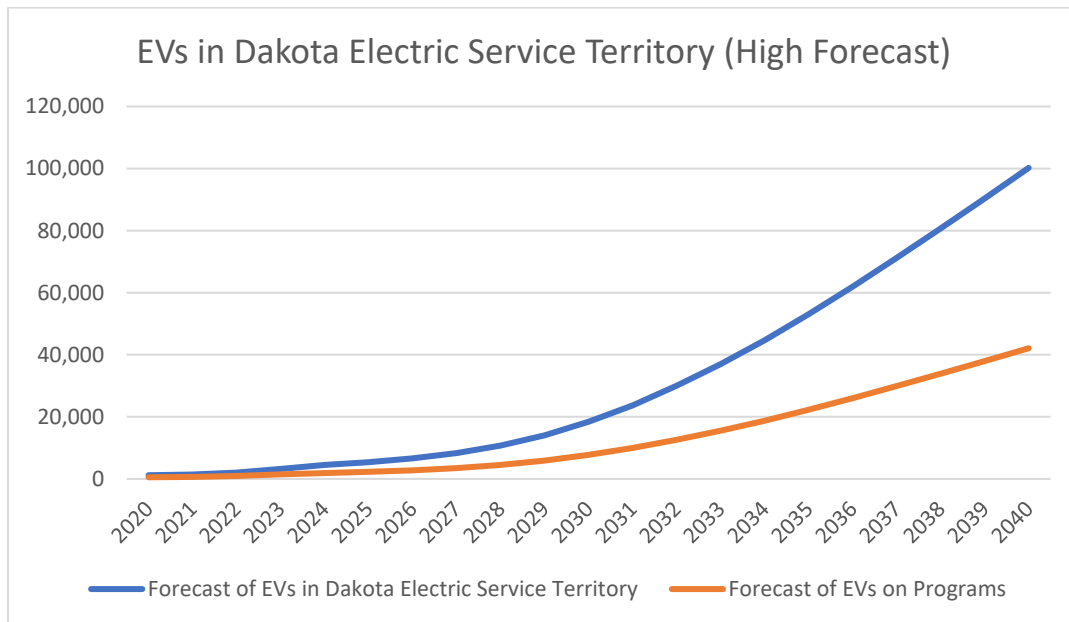
⁹ 2022 Minnesota Electric Vehicle Plan, MN Department of Transportation (July 2022) <https://mdl.mndot.gov/items/m16893>

Graph 8. Annual EV Sales Forecast



Based on its review of EV data in its service territory, Dakota Electric believes that the statewide 2022 MnDOT high prediction is a reasonable starting point to forecast EV sales for the Dakota Electric service territory as the high forecast is the closest forecast to actual sales over the recent years. The following graph shows the total number of EVs forecasted for the Dakota Electric service territory. The top line is the total number of EVs forecasted, and the second line is the vehicles expected to be on one of the Cooperatives' off-peak rates. For planning purposes, the amount of "off-peak" EVs is forecasted to remain around 40% of the total number of vehicles. This participation rate is based on a comparison of the Commission's EV registration counts in the Dakota Electric service territory versus the number of members currently on one of the Cooperatives' special EV rates. Although this participation rate has declined in recent years, Dakota Electric notes that this participation rate is still very high compared to other utilities and remains strong with the increased number of EVs on system. Dakota Electric is optimistic that it can continue to innovate new, and improve our existing, EV programs to attract more members to join these programs which will help reduce the impact of the EVs on the distribution system and wholesale power costs.

Graph 9. Forecast of Electric Vehicles Charging on the Dakota Electric System



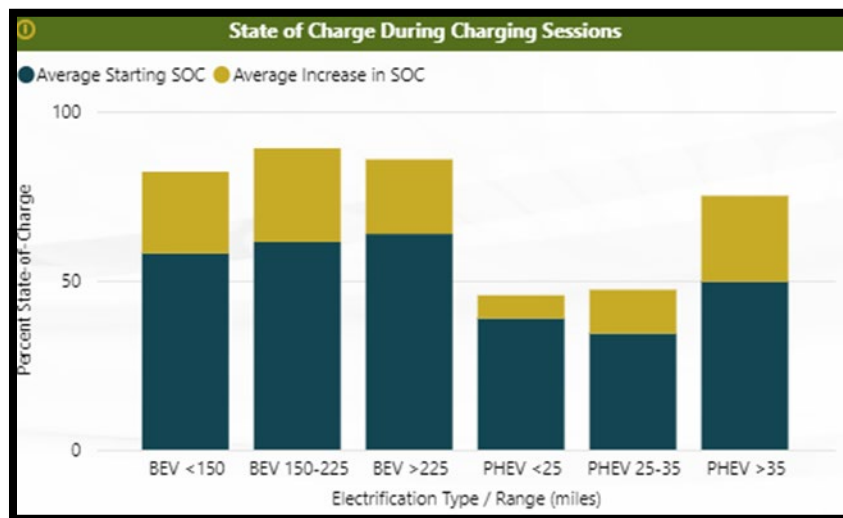
Given the growing importance of EVs, there are regular questions in the news media and regulatory circles about EVs and the electric grid, including whether the grid is capable of supporting all the new EV charging. As part of Dakota Electric’s distribution planning process, this question has been studied and, as we learn more about how EVs are being used, this issue continues to be reviewed. How EVs are charged can have a significant impact upon the distribution system. As with all electrical utilization, diversity is critical. For example, if every person in the United States, or even just Minnesota, would turn on a light switch at the exact same time, the electrical system would likely collapse. However, in practice, there is diversity in how we use electricity and the impact to the electrical grid is moderated because when one person turns on a light switch there is likely another individual that is turning off a light switch somewhere else. Since charging EVs is energy intensive, providing programs and systems to help diversify when charging occurs will be critical to reducing the impacts of electrical vehicles. Forecasting how much energy is required to charge a vehicle, and associated demand requirements (when during the day they will be charging), are important factors to understand. Being able to forecast and control these parameters is important to ensure the distribution system will have enough capacity to support the growth in member ownership of EVs.

Using our new AGi meters, Dakota Electric engineers continue to learn how our membership is charging their EVs. In 2025, with over 1,400 members on our TOU EV charging rate, we can see how the membership utilizes that rate to recharge their vehicles. Given this detailed information, the engineers have learned that most residential EVs only need to charge for around 2.5 hours per day. In addition, the data shows that many users do not charge their vehicle every day and that some only plug in their EVs for recharging every 3 or 4 days.

The figure below is from Energetics “EV Watts” website and supports the thought that consumers are plugging in every few days as they are trying to keep their vehicle battery operations within the 20-80% capacity band.¹⁰ This approach limits the amount of time where the vehicle is totally charged. Using this approach, the battery is expected to have a longer useful life if the battery is not fully recharged to 100% or totally discharged to 0% and is operated within 20-80% capacity range.

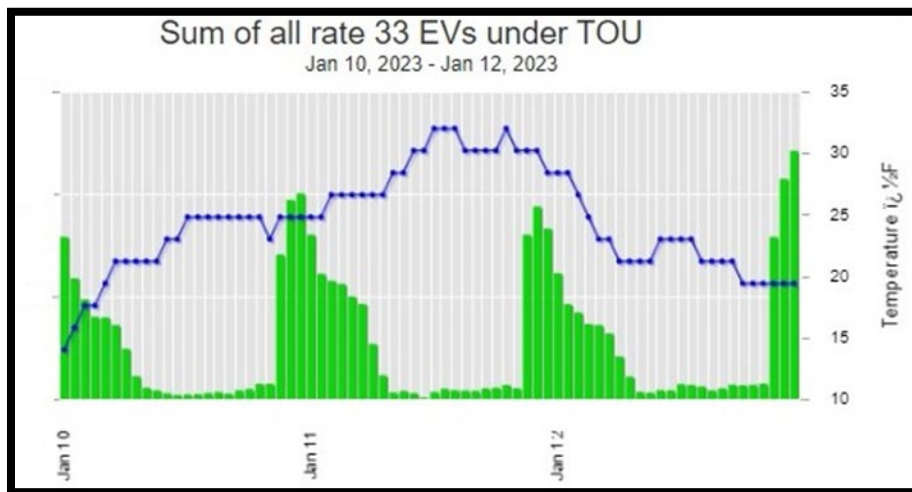
¹⁰ www.energetics.com/evwatts-vehicle-dashboard

Figure 12. State of Charge During Charging Sessions



The chart below from Dakota Electric’s AGi MDM shows an hourly interval energy use profile for electric vehicles charging under Dakota Electric’s Time-of-Use rate (Rate 33). From this chart, it is clear that many EVs are recharged within the first couple of hours of off-peak charging.

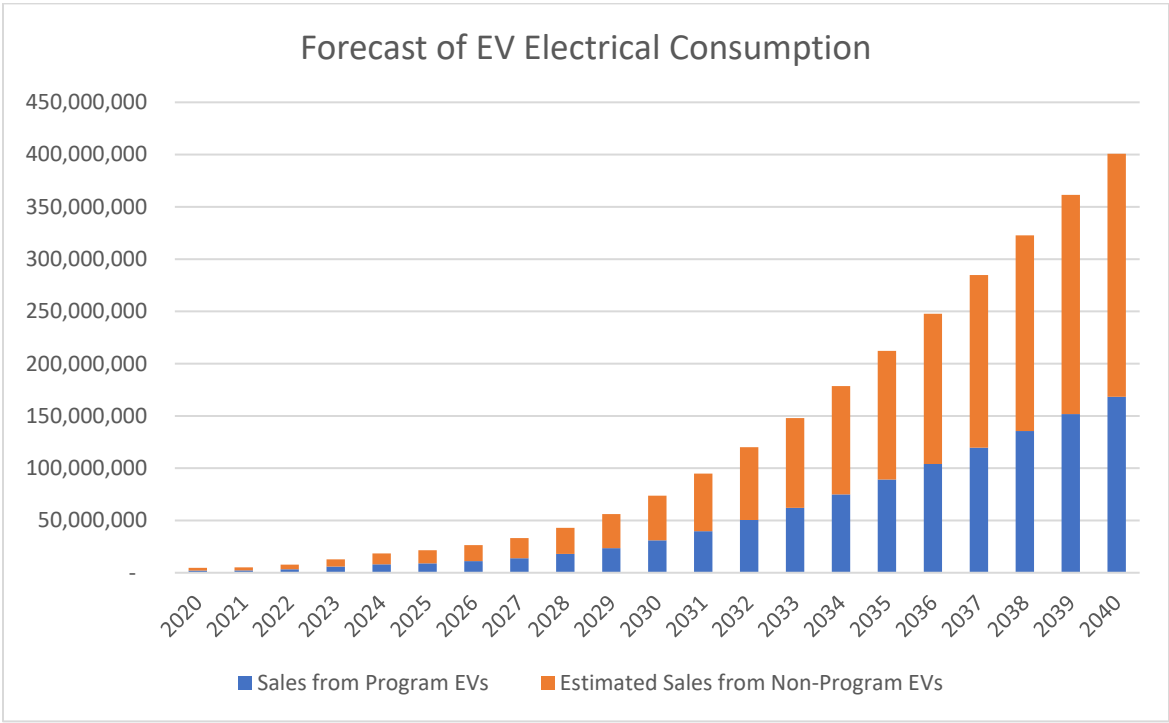
Graph 10. Daily Recharging Pattern for EVs on TOU Rate



For residential members, typical charging duration is one parameter for which we already have useful historical per vehicle data. This data can be used to forecast future consumption patterns. Looking at our existing fleet of over 1,000 residential vehicles which are enrolled on our EV programs, the average residential consumer recharges their vehicle for around 2.5 hours per day. Using interval and usage data from our TOU EV rate, we can isolate EV charging energy, and we see that the average monthly electrical usage is between 300-400 kWh. The average is closer to 400 kwh during the colder winter months and lower during the summer months. This seasonal difference is believed to be partially due to the need for heating the vehicle cabin and conditioning the battery during the winter. There may also be seasonal impacts related to lower use of the EV in the summer months due to vacations from work and longer-range travel using a non-EV.

Dakota Electric’s average residential household (without an EV) is approximately 700 kWh per month; as such, the 300-400 kWh increase in electrical consumption due to EV charging amounts to a roughly 50% increase in electrical consumption for that residence. Below is a graph forecasting the increase in electricity consumption due to automotive and light vehicles. By 2030, Dakota Electric is forecasting over 70 million additional kWh consumption. This does not include larger vehicle electrical consumption, such as fleet charging and over the road vehicle charging because there is insufficient historical data to project consumption from these uses.

Graph 11. Forecast of Electrical Consumption by EVs

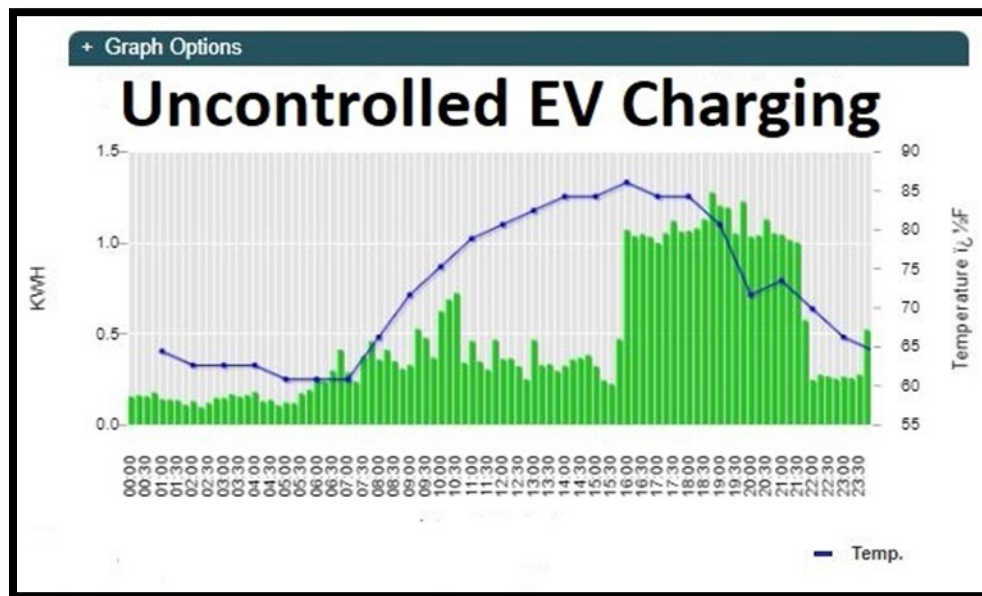


Dakota Electric is fortunate that standard design practices used over the past decades for the distribution system allow for growth in the electrical demand from our members. As discussed above, the average monthly kWh residential consumption has decreased over the past 10-20 years due to efficiency improvements in appliances, such as air conditioners, refrigerators, LED lighting, etc. There is a significant portion of Dakota Electric’s service territory that was originally designed to operate at a higher baseline energy consumption level which is similar to residential consumption with the addition of an EV. Using the new AGi advanced meters, Dakota Electric engineers have looked at the distribution transformers and found that, on average, they are loaded to around 60% at their peak loading. Thus, the existing local Dakota Electric distribution system does have some available capacity for adding additional energy consumption such as EV charging.

While, in general, the existing distribution system has available capacity, the concerns with EV charging arise given the magnitude of electrical demand with Level 2 EV charging. A residential home normally ranges from 2-5kW peak demand, while the range of typical Level 2 EV charger demand can be as high as 19 kW. Placing this large demand on top of the existing residential demand will result in a significant increase in electric capacity requirements. A practical limitation on EV charging demand is the capacity of the existing electrical wiring. A residential EV charger’s installation can be limited by the capacity of the existing electrical service installed in the home. Because of this limitation, and to limit the overall installation costs, many of the EV chargers installed are rated around 32-amps. This limitation is made so that equipment can be installed using a standard 40-amp circuit, which results in

peak electrical demand for an EV charger in the 7-9 kW range. Even with this installation limitation, 7-9kW is double or even triple the existing demand of a typical residential home.

Graph 12. Example Residential Daily Energy Consumption of Uncontrolled EV Charging



The figure above illustrates a typical home that has Level 2 EV charging. This graph shows an EV that is being charged during evening hours after the member arrives home. The usage information in this graph clearly shows that the EV is basically doubling the maximum electrical demand for this home. This graph illustrates why it is important for Dakota Electric and other utilities to incentivize consumers to shift EV charging to lower cost periods.

b. Planning for Electric Vehicles

The shift from internal combustion engine (ICE) powered transportation to electric powered vehicles (EVs) represents one of the greatest changes to how consumers in this region use the electric power system since the widespread adoption of air conditioning. This shift is complicated by a concurrent change in other consumer goods as the electrification of consumer appliances, such as water heating from primarily gas to electrical, occurs at roughly the same time. This change in the electrical power system is not isolated to the demand side of the equation. While demand for electricity is changing, the supply side of the market is also changing as electrical generation sources evolve to meet environmental and carbon regulation realities. The move from firm, largely fossil fueled, baseload generation to intermittent renewable resources is adding complexity to how we meet instantaneous electrical needs. The relocation of some generation resources from interconnection on the more robust transmission system to interconnection with the distribution system also creates additional operational constraints that must be considered. All these changes to the electrical system, such as how we use electricity, how energy is generated, and how that energy gets to the consumer, represent significant transitions to the electricity market and must be considered as part of the planning process for EVs.

This section of the IDP report focuses on how Dakota Electric is preparing for, and responding to, the shift from ICE vehicles to EVs by our members and how our membership charges these vehicles. Over the next 10 years, most forecasts expect a large shift from the use of fossil fuel to utilization of electric energy for transportation. The magnitude of this shift is unknown and may be negatively impacted by such items as supply issues for raw material for batteries, the overall higher cost of electric vehicles, and change in taxing and government policies. However,

even if the shift is slow and gradual, it will be significant because EVs represent a completely new load source. Overall, utilities need to identify and develop plans to deal with potential impacts to the electrical system. In the simplest sense, the distribution system needs to be ready to supply this new, additional load not only from the EV charging, but from other electrification sources noted above.

When planning the distribution system, Dakota Electric has developed the following classifications for how EVs are charged and used. For planning purposes, Dakota Electric sees the following distinct classes:

- Residential EV Charging. This represents vehicles purchased by our residential members and charged at their residence. The residential vehicles are expected to be mostly charged at home, in the evening and overnight hours. For single family houses and townhome units, the method of charging is very developed, and the profile of vehicle charging is well known. However, it is important to note that this classification also includes multi-family units, which is a somewhat unique subset, where the charging methods have yet to be fully developed and the resulting usage profiles are not clear. EV charging for multi-family housing, such as apartments, is a subcategory of residential EV charging and has its own set of challenges which will be discussed later in this section. The charging profile for individual vehicles remains like individual residential homes but, in multi-family installations, the chargers are more concentrated and may result in a large spot load. Further, depending upon the nature of the installation, the daily load profile will be quite different from a residential development with similar numbers of electrical vehicles being recharged.
- Light Commercial and Small businesses. This category envisions a situation where one to a handful of vehicles are associated with a company/operation. These vehicles are used during the day for driving from the business office to their customers. This could be to provide deliveries of material to multiple customers or in support of services, such as in the case of appliance repair or construction activities (e.g., contractors). These vehicles are expected to be in use during the day and recharged during the evening and nighttime hours. Just like with residential vehicles, the recharging window will be 8-12 hours each night and will likely be consistent and predictable.
- Retail Charging. Vehicles are charged at retail locations or other public locations. Locations such as shopping malls, restaurants, theaters, parks, and schools are all locations where people will naturally spend time with their vehicle parked. EV chargers located in these areas are expected to be used by individuals to “top off” their vehicle’s battery. Much of this EV charging is expected to be concurrent with the electrical demands of the business and with little electrical usage overnight. The charging is expected to have a relatively smaller demand and will be using Level 2 chargers. However, this retail charging does include a subset of applications related to DC Fast Charging (DCFC). These are high-capacity retail charging events where the charging consumer’s event is related primary to “filling” the vehicle. The charging and load dynamics of this subset of retail charging is different than typical Level 2 applications (in many respects it is like fleet and over-the-road charging) and is discussed in greater detail below.
- Fleet and Over-the-Road Charging. This class of EV recharging is expected to be 24/7 to support immediate vehicle recharging and support quickly returning the vehicle to the road. These systems are also expected to be a large consumer of electricity to support many vehicles with large batteries. Locations for this class of electrical vehicles will be concentrated in pockets of the service territory and will require the greatest energy levels of all the classes. Much of the

distribution system infrastructure for this is not in place and will need to be built using the same methods as any new consumer with a large load is connected to the distribution system, following Dakota Electric’s guidelines for new commercial loads.

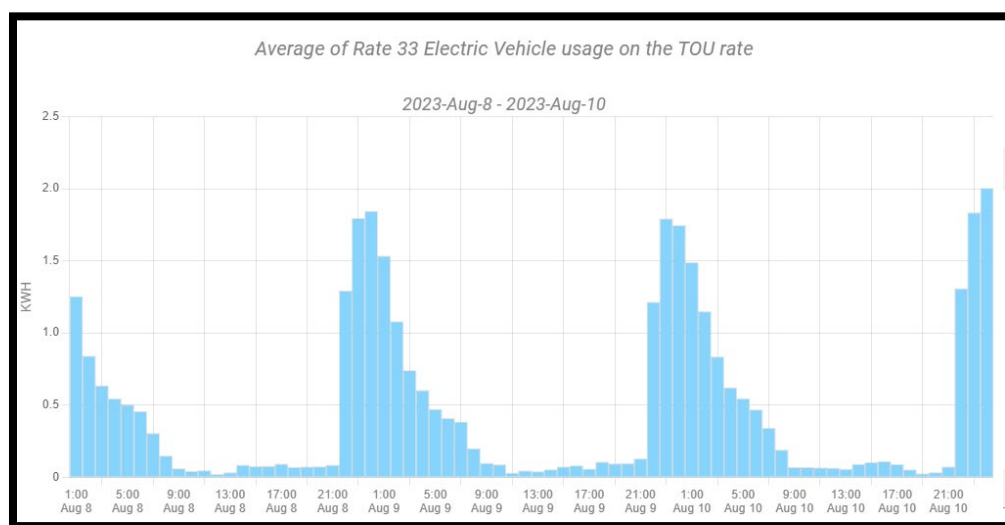
Dakota Electric’s engineers have looked at each of these classes of EV charging and developed a vision for how we expect each to impact the distribution system. The engineers continue to follow EVs and their characteristics and will continue to learn and adapt to these different EV use cases. As part of this review, they looked at the existing Dakota Electric design standards for new installations. They have modified those design standards to allow new infrastructure to better support expected EV charging levels. The following is a review of each of these charging classes, what Dakota Electric has already done to respond to each class, and how Dakota Electric is planning for a future with EV charging.

Residential EVs

The shift to EVs in the home has already started. Dakota Electric has offered its membership lower cost, EV-specific rates, for over 10 years and the number of members contacting Dakota Electric to save money by getting on one of the special EV rates continues to be strong. One of Dakota Electric’s primary focuses is reducing costs to save our members money and this effort, as it relates to EVs, is why we implemented an EV TOU charging rate option in 2012 and continue to examine other rate options. Encouraging members to charge their EVs during periods of lower cost energy not only saves money through reduced power supply costs but also helps reduce the overall electrical demands on the distribution facilities. These savings result in less need to upgrade existing facilities to provide more capacity. With the introduction in 2023 of the virtual meter EV charging rate, Dakota Electric continues to provide options for the membership to save on their monthly electric bills.

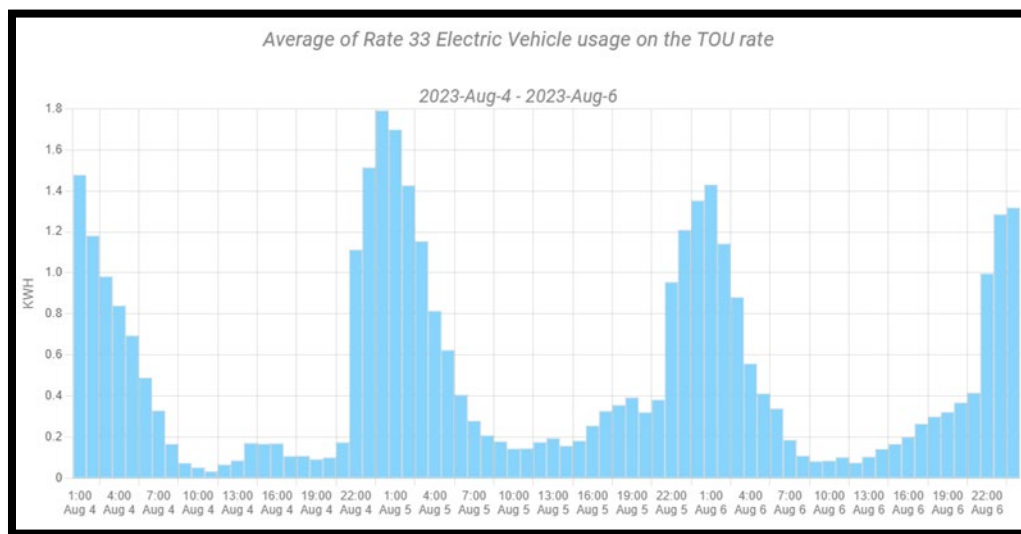
Looking into the future, as electrical demand is shifted to the off-peak periods, Dakota Electric will need to adjust the EV charging rates and/or add new rate options to spread out the recharging over the available off-peak periods. Based upon the typical driving habits of our membership, a residential EV that uses a Level 2 charger only needs 2-3 hours to fully recharge.

Graph 13. Average Electric Vehicle Charging – August Weekdays (Tuesday-Thursday)



The above graph shows typical weekday electrical vehicle charging for vehicles on the Time-Of-Use (TOU) rate for the Dakota Electric system. The lower cost TOU period currently starts at 9 pm and members vehicles start charging between 9 pm and midnight.

Graph 14. Average Electric Vehicle Charging – August Weekend (Friday – Sunday)



The above graph shows typical EV charging over a weekend in August 2023. Notice the increased daytime charging on Saturday and Sunday as those times are available as off-peak times. Some members are taking advantage of this and charging their vehicles earlier. We are also seeing higher electrical usage by members charging their vehicles on Friday night to get them ready for increased use on Saturday.

Both graphs show typical recharging patterns for a residential EV. The existing EV TOU and off-peak rates have a start time where the EV charging at the lowest rate can begin. The TOU rate's lowest cost period starts at 9 PM and the storage off-peak rate allows charging starting at 11 pm. Depending upon the rate, most members start charging at 9 or 11 pm. This results in peak EV charging demand during these late evening hours. Without any changes, as more EVs are added to the system, this period from 9-12 pm will experience a very high peak demand as most residential EVs are being recharged. After this peak demand, the period of 1 am to 5 am has lower demand. Over time, Dakota Electric will need to encourage members to recharge during this 1 am to 5 am period to reduce the impact of the 9-12 PM demand. In response to the information above, Dakota Electric recommended in our pending rate case that the peak hours be adjusted later in the evening to account for these changes to ensure that EV charging does not occur during peak period. The Cooperative also recommended adding a short morning peak period for charging because we are observing more regular morning peaks on our system (approximately two months per year recently). In addition, as more EVs are purchased, Dakota Electric will be developing ways to encourage charging during these under-utilized periods. Dakota Electric is looking at systems to see how they could play a role in management of EV charging. It is exciting that Dakota Electric's recently installed AGi system has the flexibility to support many different concepts for rate design without requiring replacement of the existing metering.

An engineering review of the expected capability of our existing infrastructure within residential developments to support EV charging has occurred regularly over the past few years. While we continue to learn more, our engineers have found that the existing distribution system is ready to supply a large amount of Level 2 EV charging with minimal modifications. In most cases, the backbone distribution system can support nearly double the amount of existing load. The overload concern is with the local distribution transformer and neighboring homes where multiple electric vehicles are recharging at the same time.

One way to help reduce the peak loading on the distribution system, and the local transformer, is diversifying the EV charging over the entire nighttime period. If the EV charging can be managed so that locally, and system wide, the electrical demands are spread over the 10pm - 6am period, then the existing distribution system can support a much greater level of EV penetration. At a high level, this can be seen as a managed charging solution. Locally, even with managed charging, there will be locations where the distribution transformer will need to be swapped out. Fundamentally, this is no different than spot load situations that can arise from time-to-time on the distribution system. However, the current concerns, specifically with transformer replacements, are supply chain issues and the general availability of replacement units. Since replacement of a distribution transformer is easy to accomplish, and installing a larger transformer results in excess energy losses and increased expense, Dakota Electric will instead replace transformers as necessary when the new loads are added to the system. Having better data from the meter through our AGI project gives Dakota Electric better tools to identify overloaded transformers and optimize the operation of distribution assets.

One challenge Dakota Electric anticipates for our members is the need to upgrade their home's electrical service to support EV charging. Most new homes have a 200-amp service and will support Level 2 chargers, but many homes built before the 1980s may only have a 100-amp service, which may require replacement. As part of service panel upgrade, the members may also need to replace the secondary wires on their property which are the connection with the Dakota Electric system.

Dakota Electric serves all types of homes, including homes built on larger lots (1-2 acres or larger), which have their own unique concerns. These members typically have secondary wires (120/240 volts) which run a long distance from the Dakota Electric transformer to the home. These secondary wires were installed by the electrician, who wired the home, and were likely the lowest cost option for the homeowner/developer at the time the home was built. The member who owns these wires is responsible for their maintenance. Just like with an extension cord, when large electrical loads are supplied over long wires, there is a voltage drop. With the installation of an EV charger, especially for high amp rated, Level 2 chargers, the members may need to upgrade the size of the secondary wires on their property. This is independent of the level of EV charging penetration on the rest of the system and is directly dependent upon the individual homeowner's level of electrical use.

Dakota Electric has noticed that there is some neighbor-to-neighbor influence that occurs with EVs, especially when clusters of EVs and other DERs occur. As these clusters form, it is anticipated there may be some overloading of the protective fuses which protect the Dakota Electric owned primary wires and cables in the residential developments. This heavier loading will be identified by engineering models and will trigger system modifications to support the additional demands. In some cases, this will require additional primary wire to be installed to split the residential loop and provide more capacity into the area. It is believed that this will be required in some older developments and only when high penetrations of EV charging occur and where it is not able to be fully diversified. Residential loops which could be the most impacted were the result of residential development installation standards during the late 1970s and early 1980s. Most residential developments which were installed in the past 20-30 years area followed design standards with a lower number of homes on a "loop" thus having more capacity for future load growth. Dakota Electric has not identified any residential development loops that require a system upgrade strictly due to electric vehicles at this time.

For new residential developments, and those which have been installed after 2022, the engineers have modified the design standards to pre-emptively reduce the maximum number of homes on any given loop and reduce the maximum number of homes on individual transformers. This decision was made to help ensure enough capacity to support a larger amount of EV charging and electrification of other residential loads.

Residential EV Charging in Multi-family Housing

As noted above, while the charging and usage characteristics for these types of locations are like single-family homes, multi-family housing has a different set of challenges to support increased EV charging penetration. The primary issue that Dakota Electric has identified involves the installation of EV charging within an apartment building. Typically, the existing electrical service for each unit is metered and sized to support the individual apartment and does not have additional capacity to support EV charging. In addition, the electrical wiring for each unit is not accessible to wire in EV charging in the parking areas. In most cases, the parking area has a separate electrical supply which supports lights and other minimum electrical demands. This electrical service is paid for by the management of the building and is not designed with spare capacity.

To provide EV charging for tenants, the management company would need to pay for additional wiring and, in most cases, add an additional electrical service. Looking at Dakota Electric's existing electrical supply to the building, there is little additional work required to add a new electrical service, other than dealing with installation issues such as paved streets, parking lots, and cemented areas, and getting power to a new service is normally not difficult. Although addressing this issue from Dakota Electric's perspective is relatively straightforward, for the building management, there are many issues which need to be thought through and resolved. Some of the important issues or questions that need to be addressed are:

- How many parking spots should have EV charging capability?
- What is physically needed to install EV charging infrastructure?
- How do the users of the EV charging pay for the energy consumed?
- Is there available space to place the utility's new distribution transformer?
- How do I pay for the cost of the overall installation and long-term maintenance?
- What can do to get the lowest rate from the utility?

Since a significant percentage of our residential members live in multi-family housing, working with the management companies to help them navigate EV charging to their facility is an important issue for Dakota Electric. Dakota Electric is working with management companies and considering various rate and rebate options and strategies that may be available to help incentivize development in multi-family facilities.

Light Commercial and Small Businesses

The first type of commercial charging we address is for a smaller business which has a few vehicles that go out during the day and return each evening. These vehicles will require charging each evening to be ready for use the next morning. This usage pattern is like residential EV charging with one difference being the presence of multiple vehicles at the business. Another expected difference may be the charging duration for these vehicles. Depending upon the type of commercial vehicle, and how it is used, they may need considerably more time to recharge than the 2-3 hours a typical residential vehicle requires. Overall, the physical changes to support EV charging at these businesses may simply require replacement of the distribution transformer or the addition of a new service with an additional distribution transformer. Dakota Electric does not foresee a significant issue with adding this type of EV charging. The only concern we have is when many of these businesses are located within the same building or in commercial centers that have the potential for Fleet EV charging. Dakota Electric will need to consider this type of charging when studying commercial areas during required system capacity upgrades. When looking at distribution planning and this type of EV charging, this may be an area where the investigation of DERMS telemetric capabilities with EV charging control to help spread out the charging may be needed.

Fleet and Over-the-Road Charging

The second type of commercial charging is fleet and over-the-road charging. Unlike light commercial and small business charging, this type of charging will result in large electrical demands in very specific and localized areas.

This type of EV charging likely will have the greatest impact on the local distribution system because its characteristics and requirements are different than other charging types. Specifically, these operations need to have the ability to charge their vehicles at any time of the day, especially during regular business hours. In terms of over-the-road trucking, a truck may arrive at a terminal any time during the day or night and, while unloading, require charging. When looking at larger delivery vehicle fleets, they may be able to charge some of their vehicles each evening but also need to charge other vehicles during the day. In either case, regardless of the usage pattern, there will be a large electrical capacity requirement to support this more intensive charging namely because most of these vehicles are larger than standard light duty vehicles. Since the electrical capacity required to support this level of charging is variable, dependent upon the number of vehicles in the fleet, and is also location specific, it does not make economic sense to pre-emptively increase the capacity of the entire distribution system ahead of time. Dakota Electric plans to respond to fleet charging centers using the same process that it currently uses for any large new load.

Dakota Electric understands that some existing logistics distribution centers will be changing out portions of their fleets as electric vehicles become available and as their existing fleets need replacement. How, and at what pace, these businesses undertake this changeover is unknown and there is no comparable use case or set of data available for Dakota Electric to know where or how these machines will be used. Waiting until the electrical needs for these operations are known will reduce the possibility of stranded assets and allow the right size and type of electrical facilities to be installed. As noted earlier, this approach is no different than the case-by-case method we use for any other large load that requires distribution system upgrades.

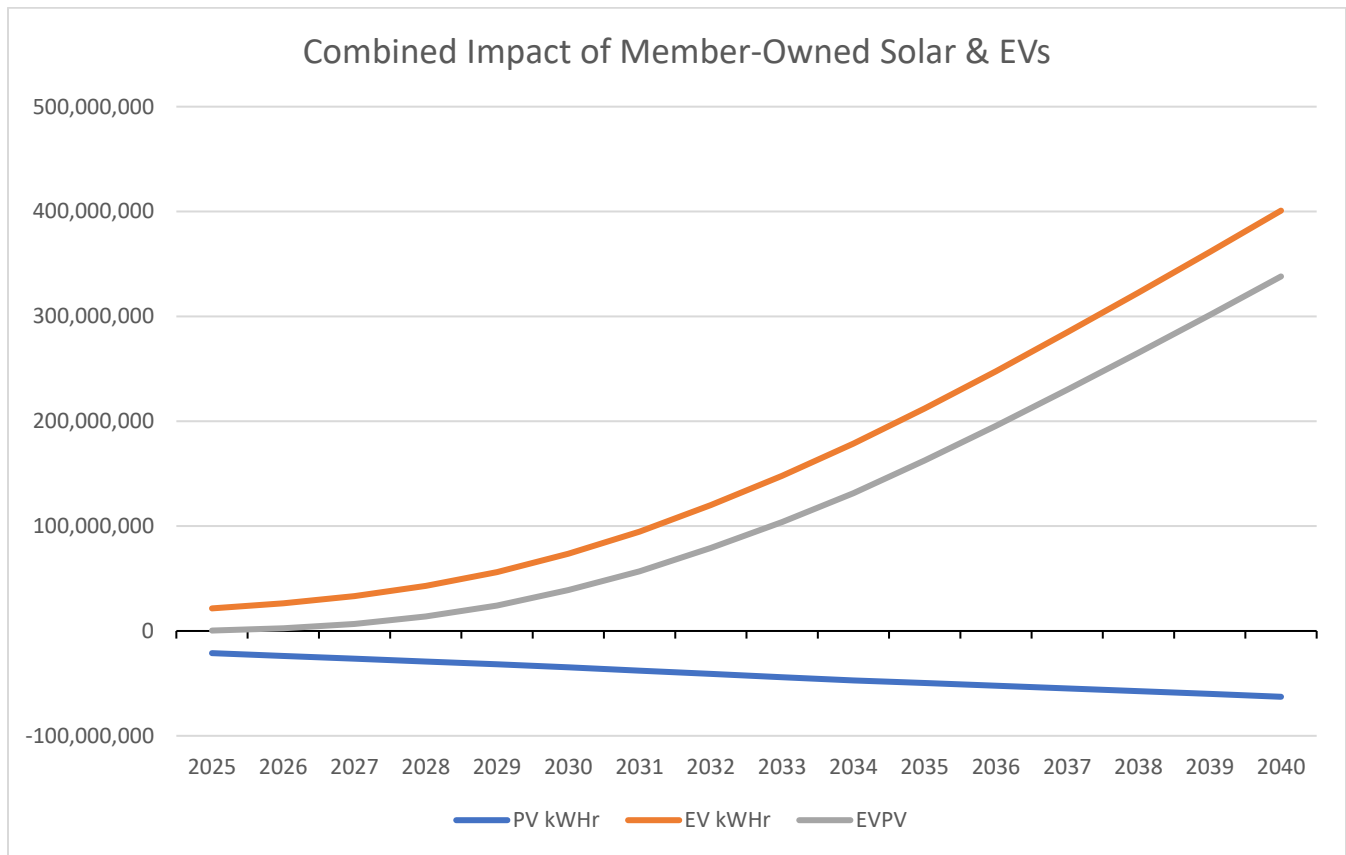
Part of Dakota Electric's future planning involves analyzing existing feeder(s) and substation capacity. With these new fleet charging electrical demands being very large and expected to be clustered in commercial/industrial developments, the main feeders supplying the commercial developments will need be studied and, when necessary, augmented to safely provide additional capacity.

One of the unknowns with fleet EV charging will be power quality issues. The distribution system has existing standards where large motors are required to have soft starting controls to reduce their step change in electrical demand during start up. Without this soft start controls upon start-up, a large motor will initially draw a large amount of power, which results in a large voltage drop. Large voltage drops from starting a large motor or from a large step change in a load, impacts other electric users in the area. Given this impact on other users, there are limits placed on how large a step change in power draw is allowed for any electrical load. When looking at DC fast chargers, these can cause step changes in load from zero to over 300kW. For much of the urban portion of the Dakota Electric distribution system, this level of step change in power demand should not be a significant issue. However, in other, particularly rural portions of our system, step changes in power in this range 200-350kW or above, could have negative power quality effects on neighboring electrical services. As part of Dakota Electric's normal interconnection process for new services, power quality issues, such as these, will be reviewed.

c. Discussion on the impact of both EVs and Member-Owned Solar

With the filing requirement modifications for the 2025 IDP to include a discussion around the combined impacts of simultaneous DER and electrification growth, a new forecast has been developed below. This forecast is a combination of the high electric vehicle sales forecast with the medium member-owned solar forecast.

Graph 15. Forecast Impact on Sales due to Member-Owned Solar and EVs



When reviewing this forecast, it is clear the forecasted growth of electric vehicles noticeably surpasses the forecasted growth (*i.e.*, sales erosion) of member-owned solar. With the addition of electric vehicle charging, Dakota Electric has started to observe a shift in when peak demand occurs on the distribution system. With the need to environmentally condition vehicles in the morning, especially during the winter season, the time of the monthly distribution peak demand has started to periodically occur in the early morning. Further, with EV charging, the evening peaks are starting to shift later in the day, coinciding when people begin charging their vehicles and when Dakota Electric's off-peak rates become available. Both of these changes are moving the high demand energy periods outside of the time when member-owned solar is able to provide energy to support the system. Dakota Electric will need to continue to work closely with Great River Energy to monitor the growth on the distribution system and verify that not only can the distribution system support the load growth, but also that the transmission system and generation resources are adequate to serve the load. In light of the forecast above, this is especially true considering that distribution interconnected DER generation will not always be concurrent when the electric vehicles may be charging.

3) Analysis of Non-Traditional Solutions (Non-Wires Alternatives)

Dakota Electric has employed what are now considered non-wires solutions for more than 40 years. By using these systems, Dakota Electric has been able to improve member reliability and save millions of dollars for the membership. Currently, Dakota Electric's membership saves over \$15 million dollars in power costs each year through the operation of the Cooperative's demand management system. The use of non-traditional approaches to operate and design the electrical system are not new to Dakota Electric and are an integral part of our system planning processes.

In the 1950s, Dakota Electric became a member of Cooperative Power Association (CPA). CPA provided transmission and energy coordination for several distribution cooperatives in Minnesota. In the 1970s, as peak loads were quickly increasing, Dakota Electric and the rest of the CPA member distribution utilities worked together to develop power purchase rates and joint load management system(s) to reduce the system peak loads. In the 1960s and 1970s, Northern States Power was the contracted supplier of energy and transmission services to this group of cooperatives and, working together using load management techniques, the cooperatives were able to reduce the power costs of the energy provided by Northern States Power. With growth in electrical demand running around 7% per year in the early 1970s, and forecasted to continue at that rate, Northern States Power informed the cooperatives that they needed to find another source of energy. As a result of this, CPA and Elk River based United Power Association (UPA), joined forces to build Coal Creek Station in North Dakota. A DC power transmission (HVDC) line from the Coal Creek Station to the Twin Cities load center was also designed and constructed to get that energy out of North Dakota.

The construction of Coal Creek Station and the HVDC line were not without controversy and represented significant capital investments; as such, the need to control the cooperatives' peak demand, in an effort to avoid or defer additional plant construction, drove CPA and its members to continue the development of their load management systems. Throughout the 1980s, the capabilities of the load management systems continued to grow. In the 1990s, in support of load management and better targeting of capital construction dollars, Dakota Electric decided to invest significantly in its internal systems to provide improved visibility and remote control. A SCADA system was purchased and installed to provide visibility and remote control at the substations. SCADA provided Dakota Electric with the ability to know the real-time status and flow of electricity through the substation and on each feeder (circuit). This allowed Dakota Electric to have a clear and immediate vision of how well load control was operating throughout the system and helped eliminate engineering estimates as to where additional capacity was required. This supported improved targeting of the capital dollars required for system upgrades.

Coupled with the installation of the SCADA system was the implementation of an improved demand management system. The SCADA system provided a backbone communication platform, which Dakota Electric was also able to use for the demand management system. When making these system investments, Dakota Electric also increased marketing to educate our membership about the demand management programs available to them and how working together we can all save money. In support of increasing demand management impacts, Dakota Electric created a subsidiary, owned by the membership, which worked with commercial members to install generation systems. These generation systems provide the members with outage protection and backup energy support and for the businesses to be islanded with their generation during electrical outages and over peak times. These "micro-grids" increased member reliability and paid for themselves in just a few years. They also support a more resilient grid for the rest of the membership through the ability to off-load the distribution system during times of stress.

This history of how Dakota Electric built its current demand response and load management system is an important step in understanding our commitment to helping our members. Dakota Electric continues to look for ways to utilize technology and programs for our membership to reduce costs and improve reliability and resiliency. The most recent example of using technology was leveraging our AGI advanced meters to provide a lower cost virtual metered EV charging option. This is just a small example of Dakota Electric's use of non-wires (non-traditional) methods to help our membership.

a) Distribution System Projects of Significant Cost

Section E.1. Dakota Electric 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 two (2) million dollars. For 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.

Dakota Electric has several projects planned for construction over the next 5 years which exceed two (\$2) million dollars. The following is a discussion of the projects with total cost greater than two million dollars, which are included in the Section 5.cc, and how the viability of their project scopes would compare to a non-wires alternative.

- 1) The first set of projects with costs greater than \$2 million that are analyzed involve replacement of aging substation equipment. Over the next 10 years, Dakota Electric has plans to replace the transformer and switchgear at several substations. The existing equipment identified is currently over 30 years old, with many of the pieces of equipment already over 40 years old. The life expectancy of this equipment is 30-40 years, and, as the equipment continues to age, the risk of failure increases. Prior to current supply chain issues, it was possible to repair or replace equipment within a few months, but now the repair or replacement time is years. The ability to obtain replacement parts is also difficult or non-existent for older switchgear. With the long supply chain lead times for obtaining replacement equipment, the risk of a substation failure, coupled with an adjacent substation failure, has greatly increased, putting greater reliability risk on our membership. This dual contingency, while rare, could result in a long duration outage to an area and would be unacceptable. Thus, Dakota Electric has initiated substation rejuvenation projects to replace older substation equipment with new equipment to reduce this risk for our membership. The analysis in this IDP Report looks at the economics and reliability of non-wires solutions to replace, or at least delay, the capital expenditures for equipment replacement. The primary consideration is whether a non-wires solution can be installed which will meet the system capacity needs if a transformer or substation switchgear fails and whether that non-wires solution is able to meet the reliability and capacity needs during the time required to repair/replace the failed substation equipment.

Projects with estimated costs greater than \$2 million as listed in Section 5.cc that are not suitable for a non-wires analysis are as listed below. In addition to reliability concerns due to aging equipment, as noted above, these projects have not been further considered for NWA analysis specifically because their existing location, size requirements of a NWA, and related land purchasing costs, make these projects unsuitable for additional analysis.

- i. Increase Capacity at Lakeville Substation
 - ii. Fischer Substation Rebuild
 - iii. Burnsville Substation Rebuild
 - iv. Colonial Hills Substation Rebuild
- 2) Dakota Electric has identified an aging substation due for replacement or rejuvenation. The current location of the substation is not ideal and is landlocked in terms of expansion. With the age of the substation and the non-ideal location, Dakota Electric is considering relocating this substation to a new location. Moving the substation further north will help the surrounding area's reliability. It will be closer to adjacent substations to allow for back feeding during contingency. Dakota Electric is currently reviewing load growth forecasts in the area to identify the ideal location and capacity size that will be needed. Dakota Electric will consider an NWA in lieu of, or in addition to, a substation, but the project is currently speculative and still being researched so an NWA is not included in this report. Dakota Electric expects to discuss this NWA in the 2027 IDP but believes the scope that was identified in the below Section 3.d. is similar in nature to this future project.

b) Basic Requirements for Non-wires Solutions

As we look at non-wires solutions, Dakota Electric developed a set of requirements for which any solution will need to provide to support reliable electrical supply for our members. It is important to note that cost is not the only variable which must be analyzed. For a non-wires solution to replace the upgrade of a distribution circuit or delay the upgrade or installation of a new substation, the non-wires solution would need to provide, at a minimum, the following:

- 1) Firm energy output when requested. Since most DER systems are intermittent source of energy, the energy output may not be available when required. If a DER is to be considered as a non-wires solution, the DER will be required to provide firm energy when requested. Failure to provide firm energy will cause power outages to members in that area, since the distribution system was not upgraded and is not available to provide that energy.
- 2) Provide firm energy for the duration of the need. The DER will be required to provide firm energy output for the entire duration of need. The duration will depend upon the needs of the loads in that area and support available from adjacent facilities. The use of a DER in place of capital dollars to add circuits will put the DER system in a critical role of providing firm energy for the duration of the load's energy demand requiring DER output.
- 3) Emergency repair/replacement of failed DER system components. If the DER is used in place of upgrading the distribution system, it is critical that the DER is always available to provide firm energy service. If a component of the DER fails, this must be repaired or replaced in an expeditious manner. Failure to repair, and return the DER to active service, puts all the electrical energy supply to members in that area in jeopardy. Any DER receiving energy credits will be required to agree to a restoration/repair response time frame. Traditional solutions are supported by spare equipment available in the utility's inventory, which can be quickly used to replace the failed component. The DER solution needs to provide the same level of reliability.
- 4) Available land located at or nearby the use-case of the solution. The DER needs to be able to effectively replace or supplement the wired alternative of the distribution upgrade, so it is important that there is available land capacity to physically build the DER, including proper setbacks. Traditional substation locations generally have a smaller footprint when compared to DER alternatives so replacing existing substations or adding DERs to them may be physically impossible without acquiring existing land. In denser suburban areas, there may be existing homes or businesses adjacent to a substation that will need to be considered during the siting process. Also, it is important to consider that if a distribution substation is not built prior to an area developing, the future ability to site a new substation with the associated transmission lines may not be possible. Limited land availability for a substation, and future landowner objections to transmission lines, may make it impossible to permit a substation in the future. The DER solution needs to consider existing and future load growth and land availability if additional capacity is required.

c) Basis for Costs use in the Non-Wires Analysis

Dakota Electric considered the following cost categories when conducting its non-wires analysis:

- 1) Utility Equipment: The costs of substation transformers, switchgear, and all utility equipment have been impacted by global demand for these products and increased demand for the raw materials

used in building equipment. Manufacturers are also impacted by other factors, including limited production capacity and a tight labor market. Overall, this has resulted in a large cost increase for equipment used by the distribution utilities. The typical substation transformer cost was around \$600,000 - \$700,000 in 2019 and the lead time from signing a purchase order to delivery was 10-12 months. Since 2020, the cost of the same substation transformer has risen to around \$1,500,000 and the lead time from signing a purchase order to delivery is over 3 years. The cost of substation equipment used in this analysis has been increased to reflect the current high cost of materials.

- 2) **Renewable Energy Systems:** The cost of renewable energy projects, including energy storage, has been impacted by supply chain issues and overall increased demand. With significant federal funding dollars available in support of renewable projects in recent years, and the expected expiration of certain tax incentives next year, the overall demand for these systems has increased, and the supply chain is not yet fully developed to support the level of demand which is occurring. The NREL forecast for 2025 includes some price moderation in future years, but the costs for many renewable energy systems are higher than previously forecast. All the costs for renewable energy systems are based upon the NREL 2024 Annual Technology Baseline forecasts.
- 3) **Solar Systems:** In past years, the costs of larger solar systems have moderated as better designs and improvements in the costs of the components have occurred. However, as with all the renewable energy systems, recent demand and supply chain considerations have affected the cost of these systems. We find that costs have increased significantly over the past few years. The following costs of utility scale solar for 2025 installations are from the NREL 2024 forecasts, which do not fully incorporate the high costs of renewable energy systems or potential impacts from recent changes in tax legislation.

Table 6. Utility Scale Solar Costs, Moderate Forecast

Utility Scale Solar ¹¹	Cost
\$/kW	\$1,491.7
Annual O&M costs (\$/kW)	\$21

Alternately, Dakota Electric has also been part of a consortia of MN Electric Cooperatives that have been working with a developer to add solar to the Dakota Electric grid via a Power Purchase Agreement (PPA). Dakota Electric would contractually purchase all the solar energy from any sites found. In working with the developer, it has been discovered that most townships with practical solar sites in Dakota Electric's service territory have permitting restrictions that restrict or disallow utility-scale solar.

- 4) **Energy Storage:** For energy storage, vendor focus has been on larger installations due to the economics of scale and their ability to optimize their internal project costs. In 2021, Dakota Electric sent out an RFP for a 2 MW/8 MWH energy storage facility and received a serious proposal from only one vendor. Even that vendor was struggling to be able to provide a system of that size and, after providing the quote, could not hold that price outside of a 30-day window.

¹¹ https://atb.nrel.gov/electricity/2024/utility-scale_pv - NREL 2022 - Utility Scale PV – 2025 Medium Forecast – 20-year cost recovery – Class 9 Southern Minnesota Installation.

Several vendors told us that the proposed system was small, and they were instead focused on much larger systems which were being requested by utilities.

The costs for energy storage systems used in the following analysis are from a 2024 NREL Annual Technology Baseline report. The numbers are the 2025 forecasted costs from the 2022 study. The O&M costs include round-trip energy losses and replacement of failed equipment.

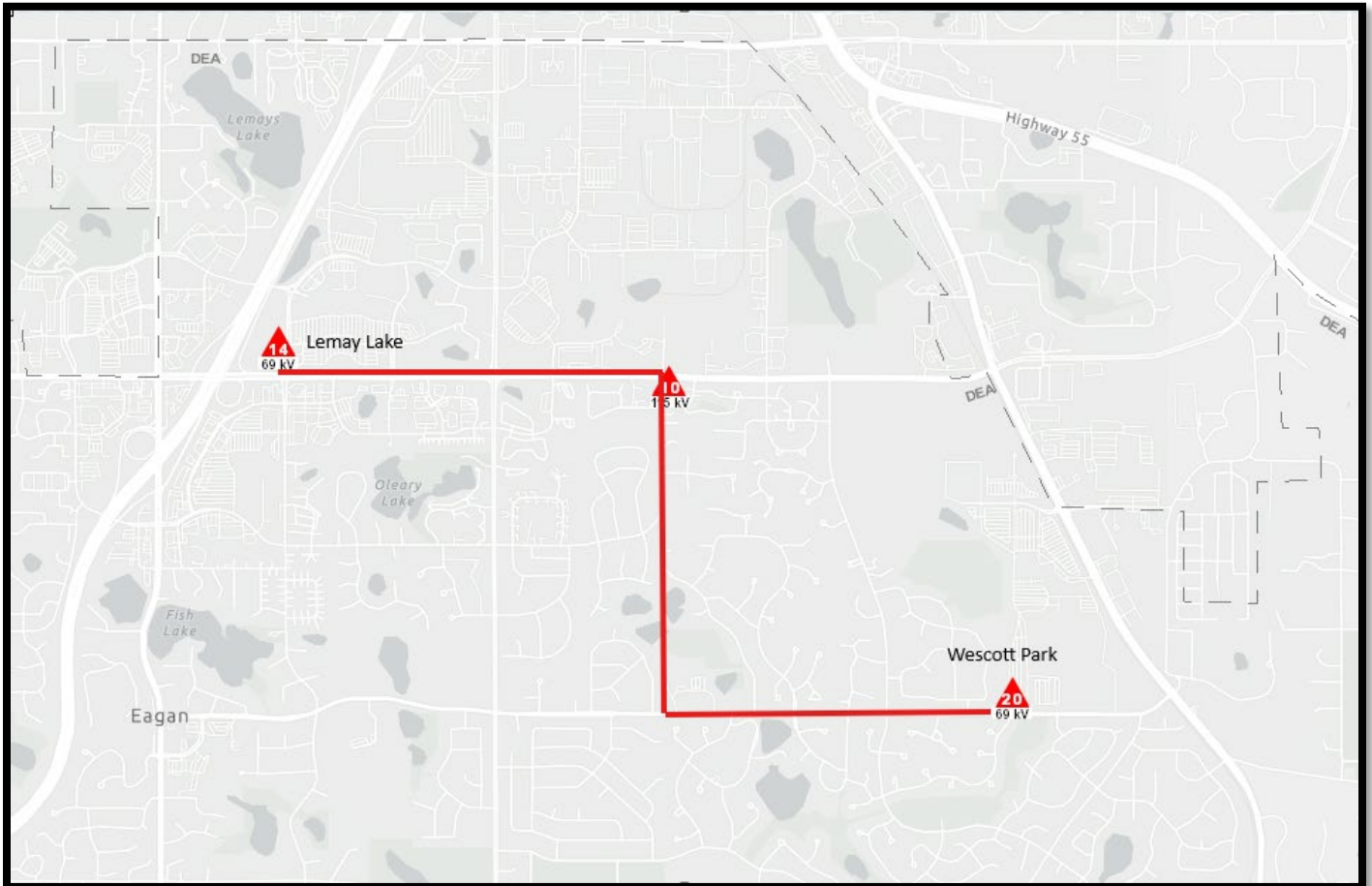
Table 7. Utility Scale Energy Storage Costs, Moderate forecast

Utility Scale Energy	4-hour Storage
\$/kW	\$1,711.40
O&M \$/kW-yr	\$38.8

d) Delaying Transmission Voltage upgrades due to load growth.

The area in northeastern Eagan is mature with most residential developments that are built out but there is a moderate opportunity for additional growth. However, the two substations in this area are currently served by 69kV transmission lines which limits the potential for future growth without upgrading the substations to 115kV. The existing infrastructure can support approximately 11MW of future growth without needing upgrades. If this area were to see additional growth that matches a typical residential load profile, there could be an opportunity to delay or defer the transmission and substation voltage upgrades by using a 4-hour BESS to provide energy during the peak periods and serve the remaining load with existing infrastructure. This scenario is of particular interest as both substations are served by the same transmission line and upgrading the voltage on one substation will necessitate an upgrade of the second substation as well. The assumption is that an 8 MW / 32 MWhr BESS would provide sufficient capacity to reduce typical residential load peaks.

Figure 13. 69kV Substation in Eagan area



Summary of Assumptions and Costs

Below is an estimate of the various cost considerations used for all scenarios. The analysis is a high-level study of benefits, costs, and risks to evaluate the different options.

- Land costs.
 - \$300,000 per acre for land near the substation site.
- \$200,000 to permit and develop land for the BESS near the substation site (e.g., grading, access roads, landscaping)
- \$1,500,000 For a 115kV to 12.5kV substation transformer.
- \$100,000 for a 2000A circuit switcher
- 5% annual interest rate for Net Present Value Calculations.
- Battery Energy Storage System Costs:
 - \$1,711 Per kW for energy storage infrastructure, with 4 hours of energy
 - 10% round trip energy losses (90% efficiency)
 - 10 years of useful life for energy storage before refurbishing.
 - \$39/kW for BESS annual operating costs.
 - Energy storage output is 80% coincident with Dakota Electric monthly peak.

A solar array sited with the BESS was not included in this scenario analysis as there is very little available land in this area of Dakota Electric's service territory; as such, was not studied further.

i) Option 1A – Upgrade to 115 kV Substation Equipment

Substation equipment upgrades would be able to be completed within the footprint of the existing substation, and the costs to perform this work would likely be transformer and switchgear equipment. This equipment would have an expected life of 40+ years. It is Important to note that these cost estimates are strictly for upgrades within the substation as related to the distribution system, there may be additional costs associated with upgrading transmission lines to 115kV, but these costs would be handled by Great River Energy as part of their regular local transmission budget.

Table 8. Option 1A – 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

ii) Option 1B – Deferring Transmission Voltage Upgrades Using Energy Storage System

This option is to add a BESS adjacent to one of the existing 69 kV substations in order to defer the purchase and installation of substation transformers, circuit switchers, and transmission line upgrades for a few years using an BESS to supply the daily peak loads.

A key assumption of this option is that the BESS can be charged from the grid each evening and then have sufficient capacity to augment the existing feeders from the neighboring substations. This assumption requires the new loads to have very low evening and overnight demand to allow the BESS to be recharged from neighboring substations. The BESS will also need to be able to cycle daily, which is known to be hard on the battery and reduces the life of the ESS. Dakota Electric also assumed that in the event a neighboring substation is lost, there is enough existing redundancy and capacity in the existing system to allow the energy storage device to be recharged during the evening and overnight hours. This assumption may not always be true and is one significant risk when considering an energy storage option.

As noted above, a 10% loss of energy with the charging and discharging of the BESS is assumed.

Since the load to be supplied by this device has not been built, the required capacity (MWhr) of the energy storage is unknown. For this high-level analysis, Dakota Electric assumed that new load would be like a typical residential member. Using this assumption, the load would peak during the morning and evenings with decreased electrical demand during the day. The energy storage system would need to be sized to supply the peaks that are above the existing system capability. This electrical energy would need to be supplied for many hours on most days of the year.

Dakota Electric assumed this option could defer substation equipment costs for 10 years, which is a typical useful life for a BESS. Since this BESS needs to operate to support load, there is not any value assumed due to energy arbitrage.

Dakota Electric also considered additional potential benefits in its review of the BESS. This analysis credits the BESS for reducing 80% of the peak demand charges over traditional power supply options. The analysis also gives credit to

the BESS for charging the system using low cost, off-peak energy and then releasing the energy during on-peak hours. These benefits are partially offset by the round-trip energy losses of the BESS through charging and discharging. For the analysis, the BESS was assumed to last for 10 years. No additional costs for renewing the batteries were included within those 10 years. At the end of 10 years, the battery system was retired.

Table 9. Option 1B - Estimate Cost for Slow Load Growth

Project Year	Description	Cost 2025 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land (1-2 acres)	\$600,000	\$600,000
	Permitting and Development of the Site	\$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

Option 1B requires the energy storage system to have the capacity to carry the energy demand that is above the existing infrastructure capacity for most of the day, every day. For this option the amount of energy which could be unserved by the existing infrastructure could be large. Given this fact, the energy capacity requirements of the BESS are significant and increases the overall cost of this option. For these high-level estimates, a detailed analysis of the load duration curves versus energy storage sizing was not considered. The NPV cost differences between the traditional solution (Option 1A) at \$5.3 million and Option 1B scenario at \$17.5 million are sufficiently large such that additional detailed analysis of Option 1B was not warranted.

In addition to the higher costs of Option 1B, the option of using energy storage has additional reliability and resiliency risks over the traditional substation construction. There are significant risks when relying on the BESS to supply a large amount of energy which would not be able to be supplied by the existing infrastructure. The following are the two main risks associated with not being able to reliably supply the load using the BESS.

- Failure of the BESS – The repair time for replacing a failed component within the BESS is unknown. Getting spare components to repair a portion of the BESS would be a difficult process. Spare components are not readily available within hours as with traditional solutions. Due to the failure of the BESS system, some of the members in the area could go without power for an extended period of time until replacement components are available.
- The BESS must have existing electrical infrastructure available every night to allow recharging of the BESS. Without the existing wires and adjacent substations, the BESS cannot recharge for future service. Since the existing infrastructure is not always available, due to storms and other failures, the risk of not being able to recharge the energy storage system is significant and tangible.

Additionally, when considering forgoing traditional substation construction, a detailed study of the load growth assumptions will need to be completed with a very high level of confidence. If load growth occurs faster than forecasted, the traditional substation upgrades may be required sooner than 10 years.

e) Project Types That Lend Themselves to Non-Traditional Solutions

Section E.2.a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability).

Dakota Electric has found that demand side management or load management programs have as great of potential as a non-wire solution. However, for these methods to achieve a non-wires solution, the area associated with these solutions needs to be geographically large and include a significant number of services. The area has to be sufficiently large to ensure that the utility can engage with enough homes and business to achieve satisfactory load control and diversity such that system reliability is maintained. The take-rate (acceptance) for demand side management is far less than 100% and, in the long run, there is appreciable attrition within the loads being controlled. In other words, not every member who signs up for demand side management will remain on the program. The only alternative to this issue is to make demand side management a compulsory function of utility service, which is not a realistic option or consideration because it would represent a fundamental change in how Dakota Electric, and other utilities, approach utility service.

Related to this topic, before the more widespread installation of distributed solar in our service territory, the expectation was that if enough members installed solar systems, these systems would provide a significant percentage of their capacity to allow their production to reduce the need for additional distribution capacity. Using its AGI program and AMI meters, Dakota Electric has used around 1,500 DER production meters to monitor DER systems in its service territory and test this expectation. Based on a review of these production meters, Dakota Electric has not observed the expected diversity from a larger group of solar systems that is necessary to enable non-wires solutions. Dakota Electric's review of its production data also shows that the loss of DER generation output from solar systems on our system is concurrent with each other, which means there is not sufficient diversity in the loss of production.

f) Timeline Required to Consider Non-Traditional Solution Alternatives

Section E.2.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).

The ability to respond to new loads and reconstruction of portions of the distribution system in a short time is a core requirement for Dakota Electric. This core requirement is the same for either traditional solutions or non-wires solutions. Most commonly, the construction of new, or rebuilding of the existing distribution system, is triggered by a notice of a new load requesting connection, a road rebuild which requires replacement of existing electrical facilities, or equipment which is old and needs to be replaced. For new buildings and road rebuilds, the utilities receive limited prior notification. Many times, the notice to the utility is a few months or even weeks before the distribution addition or modification is required. Considering these issues, and the long lead times currently for non-wires solutions, it makes these options even more difficult to implement, and use, on the Dakota Electric system. In the case where aging equipment is being considered for replacement, there could be enough time to analyze alternative solutions to firm up an unreliable line and defer rebuilding the older facilities.

It is well known that the lead time for utility equipment has grown longer since COVID. The supply chain issues have doubled or tripled some of the lead times in the past few years. Since the equipment required for utility operations has been standardized over the years, utilities are able to order this standard equipment before they know the details about future projects. Equipment such as transformers and wire can be inventoried and are ready for the

next project. Non-traditional equipment, such as solar and BESS systems, have experienced some of the same increases in lead time and availability. Since non-traditional equipment has not yet shown to be economical, resilient, and reliable in replacing traditional wired solutions in Minnesota, the ability to reduce lead times through stocking of non-traditional equipment has not made economic sense for our members.

g) Cost Thresholds for Consideration of Non-Traditional Solutions

Section E.2.c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed.

Through the 2019 IDP report RFI process which Dakota Electric used to analyze non-wires solutions, it became apparent that non-traditional solutions do not necessarily compete at a specific cost threshold. While economies of scale were important, the type and capacity size played a larger role in determining a non-traditional project's cost viability compared to traditional distribution projects. In the past couple of years, through the substation battery storage project and additional outreach to battery and non-wires solution vendors in preparation for this IDP Report, Dakota Electric learned that the size and scope of DER projects may be critical to getting vendors interested in bidding on the project. Smaller projects have a high percentage of overhead costs and are less attractive to vendors. For smaller utilities, like Dakota Electric, where projects will be smaller, getting engagement from vendors is more difficult. This is especially true in today's world where there are many non-wired projects being considered by utilities.

h) Screening Process for Non-Traditional Solution Alternatives

Section E.2.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.

The main concept Dakota Electric learned from the 2019 RFI exercise was that NWS are not a global solution to every distribution system problem. What was learned then is still true now; however, there are specific scenarios in which NWS can be considered in lieu of traditional building of distribution circuits. The specific scenarios for NWS are not necessarily tied to the cost level of an infrastructure project. Often, the scenarios NWS would be considered for are related to infrequent, step-change needs in available capacity for an area that is underserved for short durations.

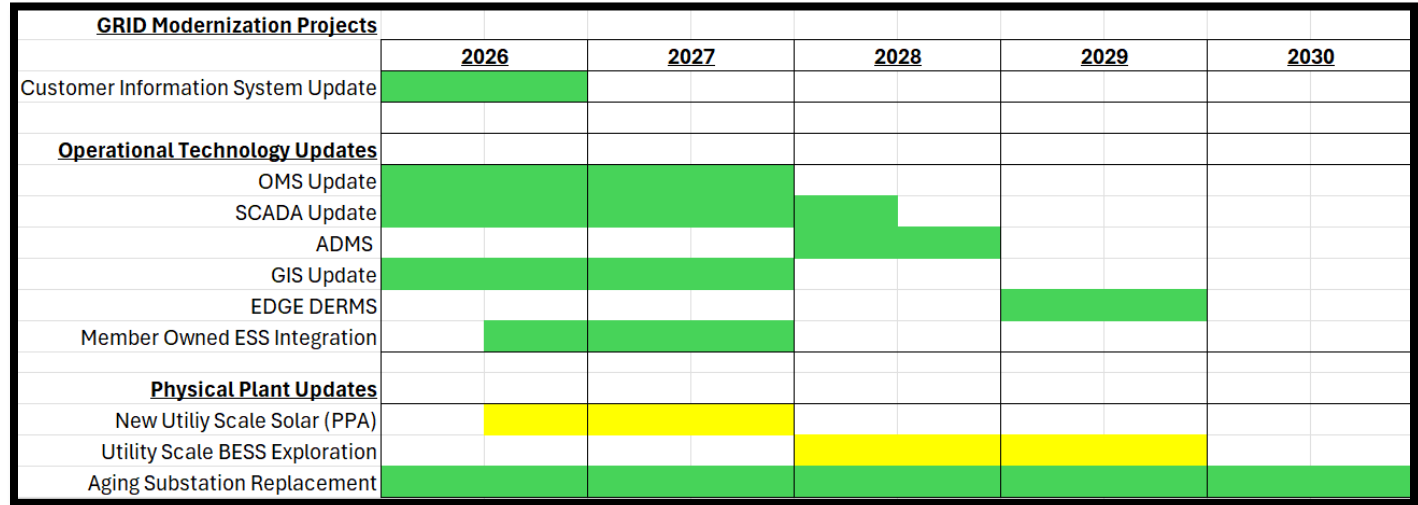
Non-wires solutions have the potential to delay capital-intensive traditional distribution projects. The delay in the capital investment may be short term, lasting 1 – 5 years; however, there may be a business case to analyze non-wires solutions further in these situations. One method to further increase the value of non-wires solutions is to design them so they can be moved and reused in a different location. Dakota Electric will continue to analyze these unique situations in future IDP reports and through the course of our regular business operations.

4) Distribution System Modernization and Infrastructure Investment Plan

Section D.1. Dakota Electric shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER and electrification futures scenarios, hosting capacity/daytime minimum load data, 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 (topics and categories listed above). Dakota Electric should include specifics of the 5-year Action Plan investments.

The safe and efficient operation of the distribution system is one of Dakota Electric’s primary objectives and requirements. An important part of this objective is a utility’s operational technology and cyber security. While these are not physical components of distribution planning, or a capital distribution plant project, they are a strategic focus for Dakota Electric and will be for the foreseeable future, including the next 5 to 10 years. Many of our internal systems must be replaced or upgraded to ensure proper cyber security and provide full functionality as the distribution system continues to evolve. Innovation has been identified as one of the key priorities in Dakota Electric’s Strategic & Operating Plan. Dakota Electric realized that not only is a significant amount of Cooperative’s operational technology approaching end of life support, but also the grid is changing to involve significant more distributed generation which requires new technologies to enable. Many of our internal systems must be replaced or upgraded to ensure proper cyber security and provide full functionality as the distribution system continues to evolve. These are complex, inter-related systems that also include sub-systems and support systems which will also need to be upgraded or replaced. The evolution of these systems requires significant time, internal resources, and monetary expenditures for Dakota Electric, and it is necessary for us to direct resources to these projects so that our membership is fully protected from cyber-security threats and that our distribution system operates as expected. Dakota Electric has identified and developed an action plan for distribution system modernization as discussed below.

Figure 14. Grid Modernization Projects Timeline



Note: 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.¹²

a) Grid Modernization and Operational Technology

AGi Project – Dakota Electric completed the AGi project in 2024. This was the largest single project in Dakota Electric’s history and is currently being used in nearly every facet of business. The operational meter data from the meters is being used daily in reviewing outages, investigating service issues, and enabling quicker response times to members. The system also serves as the backbone for Dakota Electric’s Load Management platform. The AGi project and meter interval data have enabled new program development, with the Virtual Meter rate for Electric Vehicles (Virtual Metered EV tariff, Docket No. E111/M-22-592) as an example of a rate that would not be able to be offered without the AGi system and capabilities. This rate allows members to have their EV charging applied at a lower rate, provided it is charged during off-peak hours, without needing to install a separate meter. Lower reconnection

¹² “Utility scale” solar or BESS refers to DER that is interconnected directly to the distribution system without associated load. It can also be referred as “front-of-the-meter” DER.

service fees are another example of how operational efficiency cost reduction is being passed along to Dakota Electric's members. Dakota Electric continues to review ways that the AGi project can be leveraged to develop new load management programs.

Customer Information System – Dakota Electric is currently working on implementing a new Customer Information System (CIS). This system holds all the relevant information about our members (*e.g.*, usage, billing, capital credits). Dakota Electric's current CIS system is reaching end-of-life which necessitated the project. Dakota Electric is excited about this project and believes the new system will accomplish IDP planning objective #2, enabling greater customer engagement, empowerment, and options for energy services.

Geographic Information System (GIS) Upgrade – Dakota Electric is currently investigating an upgrade to its GIS system. Dakota Electric currently uses ESRI developed GIS software. ESRI has developed a new 'Utility Network' (UN) data model to replace the current 'Geometric Network' data model. This new data model is a complete overhaul of the existing data model which is intended to streamline feature classes, allow more real-time updates and dynamic modeling, and allow for additional flexibility for complex networks and future systems. ESRI has told all utilities that they will be ending support for the 'Geometric Network' in early 2026. Current software will still work past 2026 but will not receive additional support and may become vulnerable from a cyber security standpoint. Given these realities, Dakota Electric is currently reviewing how to complete the data model upgrade. Additionally, Dakota Electric has been having continued performance issues with its Graphic Work Design (GWD) software. This software is highly integrated with the GIS and is what designers and engineers use to draft and model modifications to the distribution system.

Advanced Distribution Management System (ADMS) – Dakota Electric is planning to implement an ADMS system in 2028. An advanced distribution management system is a software platform that supports the operation of a distribution system. This includes software such as: Outage Management System (OMS), SCADA system, DERMS, and Load Management systems. It also integrates AGi meter data and GIS data, which then are used to develop a model of the system with real time information, such as: load flow, DER generation, outage locations, and maintenance switching. Dakota Electric's existing SCADA, OMS, and load management system, currently do a significant majority of the features that a single ADMS system does, although they are separate standalone programs. An ADMS system will allow operators to see a 'single panel of glass' and have all the systems needed to operate a distribution system under one program. Additionally, an ADMS system can enable more advanced engineering tools/applications which will be an advantage as more DER is connected to the distribution system.

Utility Scale Battery Energy Storage System – Over the past several years, Dakota Electric has investigated the possibility of utilizing a utility scale energy storage system. During initial reviews of these projects, information suggested that the cost of this solution would be unreasonably high and not economic under current circumstances. The other issue encountered was that the significant number of utility scale energy storage projects in the market limited the availability of vendors willing to bid on smaller projects such as what was required for Dakota Electric. Additionally, there were factors with our wholesale power supplier GRE that impacted the overall economic viability and functionality of Dakota Electric's conceptual projects. Dakota Electric continually monitors the market and economics for energy storage and notes that there have not been significant changes related to energy storage (and electrical distribution in general) since we filed our last IDP. Despite these realities, Dakota Electric remains interested and optimistic for utility scale energy storage solutions in the future.

Utility Scale Solar – Dakota Electric continues to explore expanding the distribution scale solar generation assets for its membership. As part of a consortium of other MN Electric Cooperatives, Dakota Electric has participated in a grant request that would provide funding for a solar Power Purchase Agreement for 20 years. In conjunction with the selected solar developer, Dakota Electric has found land acquisition the most difficult part of the project so far,

along with the potential PPA costs increasing as due diligence moves forward. If Dakota Electric is able to find available, economic, sites that work, and the grant request is funded, additional solar resources may be added to Dakota Electric's grid.

Behind the Meter Energy Storage Pilot Program – On March 14, 2024, the Commission approved Dakota Electric's Residential & Small Commercial Battery Energy Storage Pilot Program.¹³ The program is designed for a member's BTM energy storage system to supply the full load of their service for either a 2.5 or 4 hour period. Dakota Electric has had conversions with both third party vendors and energy storage manufacturers but unfortunately, we have been met with difficulties regarding large upfront cost in implementing a DERMS software platform, which is necessary to adequately control these devices, and manufacturers requiring a significant minimum amount of energy storage systems to interconnect to our distribution system before they will allow a program. With current member-owned BTM energy storage systems, this may take several years before we have enough systems to qualify. Dakota Electric is still optimistic about the future of BTM energy storage and is hopeful that once the ADMS project is completed, a DERMS solution will be able to integrate into an ADMS and allow the pilot program to enable different BTM energy storage programs.

Prairie Island Net Zero Initiative – Dakota Electric continues to work with the Prairie Island Community (Community) on their Net Zero Initiative. There are many components to the plans the Community have identified to support the reduction in their carbon footprint. In early 2023, Dakota Electric, through our wholesale power supplier Great River Energy, reached an agreement with the Community on construction of a 4.5MW solar facility. This facility became operational in early 2024 and it is now the fourth utility scale solar generator in the Dakota Electric service territory. The Community is currently working to expand their back-up & load management generation loop to allow additional electrification of their facilities. As discussed earlier in this report, Dakota Electric has worked with the Community to apply for Federal grants, but the Cooperative is uncertain of the results. Dakota Electric appreciates the positive relationship we have had with the Community on this initiative, and we will continue to work with them over the coming years to help implement their other plans and to work through any issues which may occur.

Electric Vehicles – Electric vehicles represent the single biggest load growth opportunity for Dakota Electric since air conditioning in the 1980s; as such, it will have a significant impact on our members and our distribution system. From a member perspective, Dakota Electric has been working over the past several years to resolve issues that limit the ability of certain members to efficiently charge vehicles (those living in apartments) or access our EV charging rates. In 2021, Dakota Electric implemented an EV TOU rate specifically for multi-family residential members and continues outreach and discussion with these members and apartment owners to find potential solutions that can efficiently promote EV charging. In 2023, Dakota Electric also implemented a novel virtual metered EV rate which leverages the data capabilities of our MDM within our AGI Project to determine EV charging and calculate a bill credit for off-peak charging. This program provides our membership, especially those who are unable to install an addition metering, another option to receive lower rates for charging EVs during lower cost times.

In addition to our EV program additions and planning decisions, Dakota Electric is also looking to the future, including the upcoming 5-to-10-year period, by examining various options and EV technologies that will provide benefits to all our membership. One area that Dakota Electric is focusing on is the continued leverage of our data analytics to identify known or suspected EV loads on our system. If EV load occurs in clusters, or in quick succession, they can begin to impact localized pockets of our distribution system. By identifying probable or potential loads, we may be able to pre-emptively make distribution or planning changes to maintain localized system reliability. Another area of focus in the near future is tele-metrics and managed charging. Our current EV programs are successful and well-received by our membership, but it is unclear whether they will represent the only option going

¹³ Docket No. E111/M-23-495, Commission Order (March 14, 2024)

forward. As the energy market continues to evolve, it may be appropriate to have program options that are more adaptable and dynamic.

Power Supply Transformation and Wholesale Power Provisions – Great River Energy, Dakota Electric’s wholesale power supplier, has worked over the last 15 years to transform their core energy supply. With the passing of Minnesota’s Carbon Free by 2040 legislation, this transformation will need to continue over the next 5 to 10 years so that Great River Energy can create and execute strategies that will allow it, and its member owners, to comply with statutory requirements. Although not directly tied to distribution planning, the make-up of our power supply is an important consideration for how we may plan certain distribution programs (*e.g.*, potential solar expansion) and the service expectations of our membership.

On the topic of solar or storage expansion, there are wholesale power considerations that may directly impact distribution planning. There is a component of our wholesale power arrangement with Great River Energy that allows Dakota Electric, and other All-Requirements cooperatives in Great River Energy, to self-generate a percentage of Dakota Electric’s load using renewable resources. This component also governs other aspects and requirements of certain self-generated projects. Dakota Electric currently has four solar facilities that operate under this agreement. Great River Energy and its members recently approved an expansion of this program and changes to requirements associated with self-generation. Dakota Electric continues to evaluate these updates and will incorporate them into future distribution planning assumptions.

Another area where there is overlap between wholesale power and distribution is demand response programming. Like all utilities in Minnesota, Dakota Electric is required to comply with energy conservation and demand response goals in Minnesota Statutes. Nearly 50% of Dakota Electric members participate in demand response programs, and we offer a wide array of different demand response and conservation options/programs. The administration of these programs, and compliance with relevant Statutes, is handled by Great River Energy. These programs are important from a distribution planning perspective because they directly impact system peak demand and potentially the amount or size of distribution equipment deployed in the field. As noted in the AGi Project section above, Dakota Electric is beginning the process of exploring different load management solutions. Dakota Electric is in the early phases of this process and is pursuing these options and ideas as part of a greater corporate strategic planning initiative.

Aging Substation Replacement — Dakota Electric’s service territory saw extraordinary growth 30 to 50 years ago as the Twin Cities expanded into Dakota County. This growth necessitated the construction of significant distribution facilities, including substations. Although Dakota Electric supports a strong, proactive maintenance schedule for our equipment, some of the substation equipment has reached, or will reach, its end of life over the next 5 to 10 years. In general, older substation equipment has a higher risk of failure and these risks increase significantly when equipment is near the end of its equipment life. Since substations serve thousands of members, equipment failures can result in significant outages and other operational issues. These significant risks are further magnified by current supply chain issues which have pushed equipment lead times for equipment out years instead of months. This puts our system at increased risk for prolonged outages and non-normal system operation which could negatively impact service quality and impair our system’s ability to handle increased DER penetration and beneficial electrification.

In light of these concerns, Dakota Electric reviewed its substation equipment and identified a group of substations that will be renovated and modernized. The Aging Substation Project began in 2024 and is expected to continue through 2029. The current budget for this project is approximately \$2-\$6 million a year; as such, this will represent a significant capital expense for Dakota Electric. The Cooperative believe these expenses are reasonable because they will modernize our system and improve overall resiliency.

5) Baseline Distribution System and Financial Information

The following section responds to the data requested in Section A of the filing requirements.

a) System Data: Modeling Software

Section A.1. Modeling software currently used and planned software deployments.

Dakota Electric continues to use Milsoft Windmill® (Milsoft) software for modeling the distribution system. Dakota Electric maintains the real-time and normal system connectivity and equipment information within an ESRI® based GIS, which includes the Outage Management System (OMS). The OMS is software which is used to maintain near-real time connectivity for the Dakota Electric system and provides real-time outage predictions and coordination support. Dakota Electric periodically extracts the configuration and equipment data from the GIS system and creates an engineering study model to be used with the Milsoft software. Section 4 of this report provides additional discussion regarding planned software deployments.

b) System Data: SCADA Penetration

Section A.2. Percentage of substations and feeders with monitoring and control capabilities, planned additions.

All of Dakota Electric substations are equipped with SCADA monitoring and control. Any future substation which Dakota Electric builds will also be equipped with SCADA monitoring and control. In addition, all our feeders have digital protective relaying and are monitored at the substation by the SCADA system.

In addition to SCADA monitoring and control within the substations, Dakota Electric continues to add SCADA to equipment on the distribution feeders. This includes voltage regulators, reclosers, and key remote switches that are installed away from the substation and located on feeders. DER that are part of the C&I Interruptible – Rate 70 also has SCADA monitoring and control installed by Dakota Electric. In addition, there are a few DER installations greater than 1 MW in size which are monitored via SCADA. The SCADA control system can remotely curtail or disconnect these DER systems from the Dakota Electric system if necessary. Dakota Electric has worked with the owners of these systems to provide this capability to support partial curtailment of DER output if needed. This function provides Dakota Electric with the ability to allow the DER to continue operation, at a lower output level, versus simply shutting off the DER during system maintenance or during emergencies and other contingencies. This arrangement is mutually beneficial, as it provides Dakota Electric with operational flexibility and DER generators with economic benefits.

Although not specifically SCADA, Dakota Electric is able to leverage a similar function through the AGI project and production meters. With these systems, Dakota Electric is able to monitor DER system voltage, energy output, and remotely shed the residential solar systems using the production meter's internal switch. This allows Dakota Electric to remotely disconnect individual solar systems if this is required to stabilize the distribution grid. This remote disconnection also allows quick reconnection of the solar system, without requiring a physical truck to deploy to the site. All these responses, or interventions, can be remotely accomplished without interrupting the main electrical service.

c) System Data: SCADA Intervals

Section A.3. 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).

With 100% SCADA monitoring at each of our substations, and on all the feeders leaving the substations, Dakota Electric has full visibility at the substation level. SCADA scans each of the monitoring points within a substation every few seconds. Except for short periods when the systems are down for maintenance, the analog data gathered approximately every minute is stored in Dakota Electric's iHistorian and is available for retrieval and analysis.¹⁴ The feeder analog data includes phase amps and feeder measurements of kW and kVARs. The substation bus phase voltage is also monitored and stored within the iHistorian system.

With the implementation of the AGi system, Dakota Electric has meters on all the services, except those members who have opted-out of having a communicating meter. The AGi meters provide 15-minute interval data. Dakota Electric also has sub-metering on the off-peak, TOU EV, and DER production meters which also provide 15-minute interval data.

d) System Data: AMI Infrastructure and Meters

Section A. 4. Number of customer meters with AMI/smart meters and those without, planned AMI- investments, and overview of functionality available.

The Commission approved Dakota Electric's AGi project and rollout in Docket No. E111/M-17-821. Dakota Electric has over 125,000 meters and over 50,000 load control receivers which have been replaced with devices which use the AGi Radio Frequency (RF) mesh communication system. Dakota Electric's AGi project to install AMI metering for all member services is complete. In early 2024, all meters were exchanged for AMI meters, except for the few members (approximately 160) that have opted out of the advanced communicating meters.

The functionality of the AGi meters and load control receivers continues to be the same as reported in Dakota Electric's 2021 and 2023 IDPs. In addition to sending back alarms or event notifications, such as high or low voltage or high meter socket temps, each AGi meter provides 15-minute interval data. The meters are programmed to provide various channels of interval data, as presented below:

Single-phase meters provide the following information for each 15-minute interval:

- 1) kWh (Delivered);
- 2) kWh (Received);
- 3) Voltage – latest 1-minute average voltage;
- 4) Minimum and maximum voltage within the 15-minute interval;
- 5) Temperature of the meter base;
- 6) Current (Meter's A leg); and
- 7) Current (Meter's B leg).

Multi-phase meters provide the following information for each 15-minute interval:

- 1) kWh (Delivered);
- 2) kWh (Received);
- 3) kVARh (Lagging);
- 4) kVARh (Leading);
- 5) kVAh (Total);
- 6) Voltage, A phase maximum within the 15-minute interval;
- 7) Voltage, A phase minimum within the 15-minute interval;
- 8) Voltage, A phase latest 1-minute average;
- 9) Voltage, B phase maximum within the 15-minute interval;

¹⁴ iHistorian is Dakota Electric's software system which stores and supports retrieval of the data collected by the SCADA system.

- 10) Voltage, B phase minimum within the 15-minute interval;
- 11) Voltage, B phase latest 1-minute average;
- 12) Voltage, C phase maximum within the 15-minute interval;
- 13) Voltage, C phase minimum within the 15-minute interval;
- 14) Voltage, C phase latest 1-minute average;
- 15) Current, A phase;
- 16) Current, B phase;
- 17) Current, C phase;
- 18) Meter base temperature;
- 19) Harmonic Distortion – Voltage phase B (VTHD); and
- 20) Harmonic Distortion – Current phase B (ITHD).

In addition to the 15-minute interval data, daily register values are also provided. The register values are used for billing and validation of the interval values and include the following information:

- 1) kWh (Delivered);
- 2) kWh (Received);
- 3) kW (Delivered) highest daily 15-minute kW for energy delivered;
- 4) kW (Received) highest daily 15-minute kW for energy received;
- 5) kVARhr (Lagging) - only on Multi-phase meters; and
- 6) kVARhr (Leading) – only on Multi-phase meters.

Since the 2021 IDP report was filed, Dakota Electric is now using the internal switch within single-phase residential meters to disconnect and reconnect the member's electrical service. The internal meter switch allows Dakota Electric to remotely turn off the flow of energy through the meter. This is a safer way to disconnect service to a home or business versus manually pulling the meter from the meter socket. When pulling the meter from the socket, there is a chance of creating an electrical arc which can cause serious injury to the person who is manually removing the meter. Dakota Electric still sends personnel to the site to make a personal visit before disconnection for non-payment, but the on-site crew can now use their iPad to send a request to the meter to open the switch. This is a safety improvement over the prior practice of physically removing the meter from the meter socket and "tabbing" the blades of the meter to disconnect the flow of energy. Eliminating the removal of the meter from the meter socket removes the potential for arc-flash events and wear and tear on the meter socket connections. Use of the internal meter switch also allows Dakota Electric to remotely reconnect the service upon resolution of the reason for the disconnection. By using the meter's internal switch, the process of disconnection and reconnection is safer and faster due to the elimination of the reconnection trip to the site.¹⁵ This reduction in travel and labor expenses also saves the member through lower reconnection fees.¹⁶

At the time this report was prepared, approximately 160 members have elected to opt-out of having an AGi meter installed at their home. These members pay the Commission-approved opt-out monthly rate and have Dakota Electric manually read their meter. The meters installed on each of these homes do not provide interval data into the MDM system, so overload analysis of the equipment supplying their home and power quality monitoring is not available for these members. Since these meters will only be read once per month, there is also limited information available for engineering models and engineering analysis.

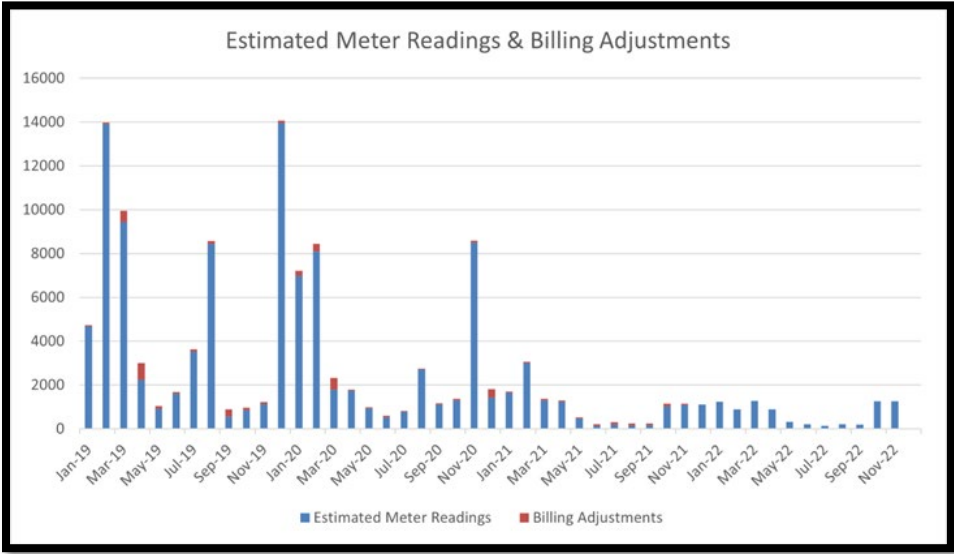
The AGi system has benefited the membership in several ways, and Dakota Electric addresses two of these clear benefits in this report. The first is directly through improved monthly billing accuracy. In the graph below, it is clear that prior to the installation of advanced meters, the amount of estimated bills and billing adjustments were greater

¹⁵ Docket No. E111/M-22-494.

¹⁶ Docket No. E111/M-22-227.

than after the introduction of remotely read meters. Initial mass meter deployment started in July 2020 and was mostly completed in January 2022. With the ability to remotely read the meters, versus meter readers manually entering in the meter reading each month, the accuracy and availability of the monthly meter readings achieved nearly 100%. The graph below does show an increase in estimated meter readings during the winter months as members turn off power to their off-peak sub-meters on their air conditioning units. Since there is no power to these off-peak meters, they cannot be read and are estimated with zero usage until power is restored in the spring.

Graph 16. Estimated Meter & Billing Adjustments Before and After AGi Meters Installed



A second benefit to members is the indirect benefit of reduced internal labor being required to estimate billing and resolve billing issues.

The AGi system’s MDM system also provides many relevant reports to Dakota Electric staff. These include reports that show capacity, rate or temperature anomalies that are investigated by field staff or billing issues that can be investigated in the office. The MDM system also provides aggregated load data for each of Dakota Electric’s distribution transformers by summing the associated meter interval values. This is valuable for Dakota Electric engineers as they review and analyze the network and allow for early identification of loading issues.

e) System Data: Coordination of System Planning

Section A.5. Discussion of how Dakota Electric Association approaches distribution system planning in consideration of and coordination with Great River Energy’s integrated resource plan, and any planned modifications or planned changes to the existing process to improve coordination and integration between the two plans from Dakota Electric Association’s perspective.

Planning Process

Dakota Electric works closely with GRE, our wholesale power supplier, in many aspects of the planning and operation of the electric distribution system. GRE organizes and supports committees and groups which include both GRE employees and employees of the member distribution cooperatives. These groups provide education, coordination, and communication between the organizations. Since Dakota Electric is a distribution-only cooperative, and only responsible for a portion of the overall delivery of electricity to its members, it is paramount

that we communicate and plan cooperatively with GRE. GRE is responsible for the security and resilience of the transmission system which supplies the Dakota Electric distribution system.

Engineers from each of the organizations are involved during the planning process to create Long-Range Transmission and Long-Range Distribution studies. The reports are shared between GRE and Dakota Electric for review before plans are finalized. When new distribution substations are proposed by Dakota Electric, GRE reviews the proposal and both GRE and Dakota Electric look at options before any plans are finalized. GRE contacts Dakota Electric, and other distribution cooperatives, during the transmission planning process to review any transmission issues within cooperative service territories and solutions are discussed amongst the parties. As part of this review process, it is not unusual for discussion of alternatives to the identified transmission issues to occur, including potential non-wires alternatives. As the electrical grid continues to evolve to meet consumer needs, the transmission and distribution planning engineers are working to create more touch points to discuss issues which impact overall design and operation. When a transmission modification or addition is selected, and it impacts Dakota Electric, we are involved in the design and permitting process as needed.

The process to interconnect new distribution substations with the transmission system has been greatly impacted by the volume of new transmission interconnections. Just a few years ago, it was possible to learn about a large new load and obtain a transmission interconnection to supply that new load with electricity within 14-24 months. For interconnections which did not require new transmission lines, the local permitting process was typically the longest lead time and biggest variable within the new distribution substation process. Now, with the significant volume of pending changes to the transmission system (e.g., new distribution substations, retiring existing generation, new transmission lines, interconnection of new generation), the lead times for review and approval of new distribution substations have become very lengthy. The previous 1–2 year process can now be up to a 3-6 year process. These longer planning horizons are illustrated by a local transmission provider signaling a 5-year notification requirement to support new substation interconnections.

Manufacturing facilities and data centers are large loads that have been in the news lately and have expressed interest in Minnesota. It is important to note that some of these load types may directly connect to the bulk transmission system, so they are separate from the type of planning envisioned in this report. That being said, regardless of potential service characteristics, when these types of loads express interest in Dakota Electric's service territory, they are asking when they can realistically expect power. Due to current interconnection timelines and long lead time equipment (e.g., transformers, switchgear), it is unlikely that these loads can be connected in the short-term unless we can serve these prospective loads using existing distribution infrastructure. Even if Dakota Electric is capable of serving the load with existing infrastructure, a prospective load may impact the transmission system. This can be complicated because GRE does not own or operate much of the transmission system in Dakota Electric's service territory. Dakota Electric is concerned that certain aspects of the transmission interconnection process, and supply chain environment, may impair the ability of the communities we serve to achieve their economic development goals and, potentially, our ability to swiftly add substation capacity for major electrification efforts.

Demand Management / Load Management / Energy Efficiency

GRE works closely with all its member distribution cooperatives to implement demand management/load management of distribution loads. GRE and Dakota Electric work together to operate and administer the Demand Management and Energy Efficiency programs. Since the start of the State of Minnesota's conservation improvement program, GRE, and its predecessors, have helped administer the planning and regulatory filings for Dakota Electric's DSM programs.¹⁷ In addition to these efforts, GRE provides support and coordination for many different energy

¹⁷ Prior to the early 2000s, Dakota Electric handled compliance, and regulatory filings for its conservation program. During this time, GRE and its predecessors aided Dakota Electric with these compliance requirements.

efficiency programs. Dakota Electric notes that even with the assistance from GRE in these matters, we remain the point of contact with our members on DSM and conservation programs.

Many of the load management programs offered by Dakota Electric would not be possible without the support and coordination of GRE and its member cooperatives. In GRE's 2022 Integrated Resource Plan (IRP), as part of their 5-year action plan, they plan to continue registration of demand response resources within the MISO capacity market. Dakota Electric has, and will continue to, work closely with GRE on the registration of demand response resources. In support of the registration, Dakota Electric has been able to utilize our AGI project systems, including the MDM and advanced meters to provide critical data to GRE on DSM historical performance. GRE utilizes the data to confirm performance and to support future registration levels. Together, GRE and its member distribution cooperatives have been able to significantly increase capacity registration levels, and Dakota Electric will continue to look for ways to improve the benefits derived from demand response programs.

Beyond demand response programs, GRE has a large portfolio of energy efficiency programs. Energy efficiency programs have been created through joint development with the distribution cooperatives and their member-owners. This represents savings to Dakota Electric's members of more than \$15 million in energy and power costs annually.

f) System Data: DER Considerations in Load Forecasting

Section A.6. Discussion of how DERs and electrification are considered in load forecasting and any expected changes in load forecasting methodology.

Dakota Electric, in conjunction with GRE, completes a long-range load forecast every two years. This long-range load forecast is over a 15-20 year period. The long-range load forecast uses historical monthly and annual energy usage by member category. For the long-range load forecast, historical growth patterns for electrification, DER penetration and generation levels are embedded in the historical monthly and annual energy usage by member category for the forecast.

Looking at historical data over the past 10 plus years for the Dakota Electric system, total residential sales have remained relatively flat despite an average increase of 1,125 residential members per year. That means, on average, Dakota Electric members are using less kWh, on an individual basis, throughout the year. This decrease in residential usage per member is driven by choices and conservation efforts such as converting lighting to LED, newer more energy efficient appliances, and increased insulation in newer homes. When considering electric vehicles, both Dakota Electric and GRE believe that there will be significant growth in sales. The issue with using historical growth patterns is that they may not be representative of future electric vehicle load growth and DER penetration. Given this fact, some manual adjustments to the long-range energy forecast are made to reflect the expected increases in DER penetration and increased EV sales. Dakota Electric worked with GRE to develop the latest long-range load forecast for the Dakota Electric service territory.

For short-range load forecasting, Dakota Electric projects 3-5 years into the future and uses the Long-Range load forecast adjusted by the prior year's peak feeder and substation loads. This short-range load forecast is used by Dakota Electric's finance department for budgeting and by engineering to identify where feeder capacity is not sufficient to meet the forecasted member electrical capacity requirements for the next year.

The prior year's actual peak demands include reductions to potential peak demands through the operation of the demand response system. Presently, Dakota Electric's peak demands occur on the hottest days during the summer months. Depending on the area supplied by the feeder, the time of day for the peak will be different, but, currently, almost all the feeders experience their peak demand during the summer months. Each fall, Dakota Electric reviews

feeder loadings from the prior summer season and develops a forecasted peak loading for the next summer. Dakota Electric includes the potential for new loads that may be added to an individual feeder in that feeder's forecasted peak loading. For new DER interconnections, Dakota Electric receives limited advanced notice of DER generation being added to a feeder. For new electrification, and specifically EVs, Dakota Electric receives either no notice or limited notice if a member participates in a load management program. These new DER and EV additions are not able to be included in the annual feeder and substation load forecasts, but it is important that Dakota Electric and GRE consider these loads when reviewing the long-range forecasts.

DER installations in the Dakota Electric service territory cannot be considered firm generation to offset the feeder electrical demands because of how they generate energy. DER installations powered by solar, or wind are intermittent and there are many hours during the year when the DER systems do not produce energy or operate at low levels. These intermittent DER systems may periodically reduce the feeder demand, but there are also peak load periods when the output from the DER is low or nonexistent. During these periods, Dakota Electric is required to ensure that there is enough feeder capacity installed to meet that electrical demand or there will be an outage. As discussed in Section 2.b. above, it is also highly likely that electric vehicles, and other electrification, may charge or have increased demand during hours when DER is not generating. Even though Dakota Electric forecasts both demand increasing due to electrification and DER generation increasing, they cannot be considered offsetting due to the nature of DER generation and the load usage periods. This is why Dakota Electric works very closely with our power supplier Great River Energy to consider the increases in electrification and DER penetration.

Cold Load Pickup - One concern that comes up in distribution planning is "cold load pickup." Cold load pickup is the surge in electrical demand after an outage. The longer the outage, the greater the surge in electrical utilization. This occurs because of the loss of diversity from running appliances. After a longer electrical outage, all the refrigerators, heaters, AC units, backup battery systems, etc. want to run, recharge, or replenish the cooling or heating which did not occur during the electrical outage. Cold load pickup is further impacted by the requirement that DER wait 5 minutes before reconnection after an outage to ensure that the electrical grid is stable. The DER interconnection standards do not discriminate between DER that generates electricity (solar), which would be valuable to quickly reconnect, and DER that uses energy, such as an energy storage device, which would be a drain on the electrical grid. All DER are currently required to follow the same reconnection (enter service) requirements.

As noted earlier in Section 2 of this report, historically, most of Dakota Electric's feeders peak in the evening, around 6-8 pm, during the summer. With the addition of EV charging, and members taking advantage of Dakota Electric's off-peak rate, we are beginning to observe feeder/substation and system peak occurring around 9-11pm. In light of these observations, Dakota Electric reviewed its time windows for Time-of-Use (TOU) rates and recommended minor changes in the Cooperative's pending general rate case.

Dakota Electric uses data from the AGi DER production meters to provide insight into the operation and performance of member-owned DER systems. Dakota Electric is currently researching how to forecast larger DER generation on the feeders. Dakota Electric will need to continue to evolve and develop new study methods and planning standards. For planning, the maximum total load behind each meter is critical and thus the potential magnitude of load which could be placed upon each of the circuits must be understood to ensure enough feeder capacity during cold load pick-up events. Using the AGi meters, with their 15-minute interval data, Dakota Electric can identify this maximum total load by using the main meter coupled with the data from the DER production meter.

Dakota Electric has a large portion of peak load which is managed by our load management system. Given this large concentration, Dakota Electric includes the operation of load management within the feeder load forecasting process. Since Dakota Electric uses the prior peak summer loads as the starting point for the substation and feeder

load forecast, the operation of load management is naturally included within these historical numbers. Historically, the GRE system peak demand and the Dakota Electric peak demand have been mostly coincidental. A typical load control day starts with control around 2 pm and continues until around 9 pm. With the registration of DSM into the MISO market, the periods of time when DSM control will be requested by GRE may change from these traditional early evening periods. This may require Dakota Electric to develop processes to use DSM to not only meet the MISO operation requirements but also create processes to identify when DSM control operations are required to be initiated to support internal operational needs.

g) System Data: System Planning Impacts of IEEE Std. 1547-2018

Section A.7. Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality).

As of October 6, 2023, the Commission issued a notice that the IEEE 1547-2018 certified inverters, also known as smart inverters, are readily available effective October 23, 2023.¹⁸ Within this Notice, the Commission also stated that effective January 1, 2024, all utilities were required to use the full implementation of the Minnesota Technical Interoperability Interconnection Requirements (MN TIIR), which requires all new inverter-based applications to use inverters certified to UL 1741-SB.

Dakota Electric does not see immediate changes in the distribution system planning process resulting from the new IEEE Standard 1547-2018. One of the key benefits from the new inverter functions is that it will help the bulk transmission system through the additional ability to ride through brief disturbances and not have the DER trip offline. The other key benefit is that it will help reduce the localized impact of high voltage resulting from the operation of the DER. The localized high voltage levels are caused by the output and, to push power out of the DER, the DER needs to raise the voltage at the terminals of the DER. If member-owned secondary wires connecting the home to the distribution system are smaller (higher resistance) and/or lengthy, the extra voltage rise at the terminals of the DER is required to push the energy back out on the distribution system. If the DER is operating during high usage times, such as EV charging, then the advanced inverter can help with the localized low voltage levels that are caused by increased electrical usage though EV charging or other larger electrical loads. The benefits of the advanced inverter functions for the distribution system are expected to be minimal when first implemented and will not immediately change how Dakota Electric models and plans the distribution system, because it will likely be many years before the penetration of DER on our system reaches a higher level where these advanced settings are more beneficial. When we reach these higher penetration levels, in aggregate, the advanced inverter functions will start to impact and benefit the day-to-day operation of the distribution system. As DER systems are integrated with the advanced inverters, the engineering models will be able to take this additional benefit into consideration.

Dakota Electric requires use of many of the advanced features of the new inverters to help maintain system voltages within the ANSI ranges. When the distribution system reaches high penetration of DER integration, the use of the Volt/Var and Volt/Watt configurations within the inverters are expected to help reduce high voltage issues resulting from operating with these higher DER penetration levels. The Volt/Var feature will not only help reduce high voltage issues at member homes caused by the solar generation but will also help reduce low voltage issues which may be caused by member EV charging. Since EV charging mostly occurs during the evening and nighttime hours, solar installations may not be on-line and able to help with low voltage issues. As more energy storage systems are included with solar installations, the ability of these systems to help reduce low voltages within the home may become a possibility.

¹⁸ Docket No. E999/CI-16-521, Commission Order (October 6, 2023).

h) System Data: Distribution System Annual Loss Percentage

Section A.8. Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages).

For Dakota Electric, system losses are determined by comparing total energy purchased to total energy sold. The energy purchased is measured by meters installed by GRE at each of the substations, energy produced by larger utility scale solar systems, and energy delivered to the distribution system from member-owned DER systems. Energy sold is measured by meters at every service location.

Historically, Dakota Electric maintains records of monthly energy purchases from GRE, the monthly energy sales to its members, and energy which is used for Dakota Electric facilities, referred to as “own use.” Dakota Electric calculates the energy losses by subtracting energy sales, and “own use” energy, from the monthly energy purchases from GRE and received from DER systems. These energy loss values are then converted to a percentage of the total energy received.

With the implementation of Dakota Electric’s AGI system, Dakota Electric receives daily meter readings. This is significant because Dakota Electric can coincide meter readings with GRE’s monthly meter readings and can more accurately calculate distribution losses. Additionally, Dakota Electric also found that unmetered streetlight usage was being considered as losses, these have been removed from the loss calculation for years 2023, 2024, and 2025.

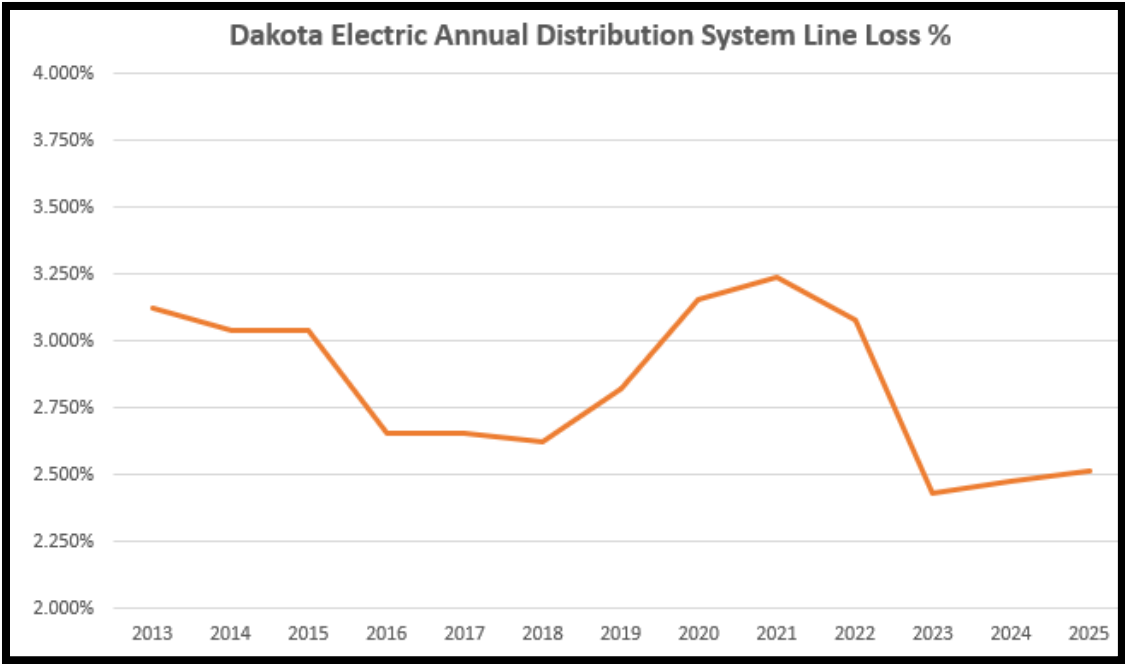
It is important to understand that losses vary from month to month due to many factors. A few of the main factors affecting losses are distribution lines and distribution transformers. The further energy must travel through distribution lines increases the associated line losses. Increasing wire size can help reduce the losses but no matter how small the line section is, there are associated line losses. Distribution transformer losses are also a significant portion of losses. There are typically two types of losses associated with a transformer, no-load losses and load losses. No-load losses are innate losses associated with a transformer simply being energized, they are constant for as long as the transformer is energized. Load losses are associated with the actual load that is flowing through the transformer. As load increases, so do the associated transformer load losses. In practice, installing the proper sized transformer is the best way to minimize both the load losses and no-load losses.

Table 10. 2024 Distribution System Losses

2024 - Months	Monthly System Loss Percentage
January	2.67%
February	2.56%
March	2.54%
April	2.42%
May	2.31%
June	2.22%
July	2.24%
August	2.28%
September	2.34%
October	2.57%
November	2.72%
December	2.78%

The table above shows monthly losses during 2024, and the graph below shows the most recent years of line loss data. Dakota Electric attributes the drop in losses from 2023 to 2025 due to the revisions and more accurate calculation methods.

Graph 17. Distribution % Energy Losses (2013-2025)



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

i) **System Data: Maximum Hourly Coincident Load (kW)**

Section A.9. The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.

The table below shows coincident demand on the Dakota Electric distribution system at the time of peak system demand for Dakota Electric: (1) at the time of peak system demand, and (2) for the GRE system peak. The peak demand (kW) at the time of GRE’s system peak is reduced through the operation of the Dakota Electric load management (demand-side management) system. Without the operation of the load management system, the peak demand at the time of the GRE peak would be greater.

Since each of the Dakota Electric distribution substations experience their peak demands at different times of the day, and different days of the year, the non-coincident sum of the substation peak demands is much greater than the coincident peak for the Dakota Electric system. Distribution planning studies must consider this diversity of demand, and the distribution system must be built to support the non-coincident demands for each of the feeders and substations.

Table 11. Historical System Peak Demand (3)

Year	System Peak Demand (MW) ⁽¹⁾⁽³⁾	Peak MW demand with Load Management Active ⁽²⁾⁽³⁾
2012	498	417
2013	462	387
2014	421	361
2015	439	409
2016	452	379
2017	428	410
2018	446	413
2019	433	370
2020	443	406
2021	468	416
2022	457	389
2023	473	455
2024	444	430
2025 YTD	442	421

- (1) This is the peak hourly demand on the Dakota Electric distribution system. This peak demand typically occurs just before the start of load control or after load control on a peak day. The values are obtained from GRE's monthly billing summary reports.
- (2) This is the peak hourly demand on the Dakota Electric system coincident with GRE's peak demand. This demand value is lower as Dakota Electric is controlling DSM loads during the time of this peak.
- (3) Demand values are reduced by any coincident DER generation amounts and may not reflect the actual maximum electrical load in the area.

j) System Data: Total Distribution Substation Capacity

Section A.10. Total distribution substation capacity in kVA.

The table below lists the total substation capacity for each of the past 5 years as of January 1. Dakota Electric has added two new substations over the past 2 years which are due to new load growth and improved contingency reliability.

Table 12. Historical Total Substation Transformer 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

k) System Data: Total Distribution Transformer Capacity

Section A.11. Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.

The total distribution transformer capacity is the sum of the kVA ratings for all the distribution transformers which provide electrical service to each of the homes and businesses on our distribution system. The total kVA capacity is like the total substation capacity, but the kVA capacity is less for the total distribution transformers as they are directly wired to supply specific homes and businesses. In addition, due to the nature of the distribution transformer, they can be periodically heavily loaded. The heavier a transformer is loaded, the shorter the life of the transformer, which is due to the heat created within the transformer from the electricity flowing through the unit. However, since the distribution transformers are physically small, the transformers can more easily dissipate the heat and withstand greater loading without experiencing loss of life. Distribution transformers also have flexibility compared to substation transformers because they do not need to maintain spare capacity to carry the neighboring load upon a failure of the neighbor's transformer.

In comparison, each substation transformer is much larger and is less able to dissipate the internal heating from the flow of electricity. This fact means that they are not able to be as heavily loaded as distribution transformers. Furthermore, the substation transformers must be sized larger, so they have spare capacity available to allow the load from neighboring substations to be switched over during contingencies, emergencies, or maintenance activities. As such, under normal daily conditions, the substation transformers are not as heavily loaded as smaller distribution transformers.

The data in the table below is from Dakota Electric's GIS system. The number of transformers represents the number of separate physical transformer tanks. For some multi-phase commercial services, individual single-phase units (transformer tanks) can be connected to form a multi-phase bank of transformers. For example, three single-phase transformers can be wired together to form a 3-phase bank.

Table 13. Total Distribution Transformer Capacity

Year	Number of Transformers	Total Transformer Rated kVA
2020	23,420	1,059,892
2021	23,725	1,087,151
2022	23,940	1,102,132
2023	24,202	1,119,718
2024	24,617	1,130,412

l) System Data: Total Overhead Distribution Miles

Section A.12. Total miles of overhead distribution wire.

The total miles of the overhead distribution line were calculated using Dakota Electric's GIS. For purposes of the table below, only the length of the line, not the total amount of wire footage used to create the line, is listed. The amount of overhead lines continue to decrease as urban areas expand, and the existing wires are replaced by underground cables. Dakota Electric is still building new overhead lines, but it typically is only in locations where existing overhead is being replaced.

Table 14. Miles of Overhead Line

Year	Miles of Overhead Lines
2020	1,177
2021	1,175
2022	1,161
2023	1,151
2024	1,146

m) System Data: Total Underground Distribution Miles

Section A.13. Total miles of underground distribution wire.

Almost all new residential and commercial developments in Dakota Electric's service territory utilize underground cables for the electrical distribution system within the development. The number of miles of underground cable continue to increase as new developments are added to the system. Dakota Electric is also strategically converting some exiting overhead lines to underground lines for reliability benefits, typically these projects are related to road moves where existing infrastructure must be relocated.

Table 15. Miles of Underground Cable

Year	Miles of Underground Cables
2020	3,041
2021	3,098
2022	3,132
2023	3,178
2024	3,218

n) System Data: Total Number of Distribution Customers

Section A.14. Total number of distribution customers.

The table below lists the total number of services connected with the Dakota Electric distribution system at the end of each year.

Table 16. Total Number of Services (Distribution Customers)

Year	Number of Member's (Services)
2020	111,007
2021	113,011
2022	114,775
2023	116,331
2024	117,620

o) System Data: DER Generation Installation Total Costs

Section A.15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc.).

For calendar years 2020-2024, the following are the direct labor and material expenses incurred in support of the interconnection and installation of DER generation.

Table 17. Cost Incurred from Interconnection & Installation of DER Generation

Category	2020 Expenses	2021 Expenses	2022 Expenses	2023 Expenses	2024 Expenses
Application Review	\$105,228	\$116,608	\$91,445	\$66,598	\$74,634
Responding to Inquiries	\$17,568	\$18,751	\$15,318	\$12,190	\$9,181
Make Ready	\$2,071	\$25,868	\$43,515	\$41,475	\$41,729
Testing	\$21,199	\$24,782	\$25,349	\$33,844	\$15,601
Total Costs	\$146,066	\$186,009	\$175,627	\$154,107	\$141,145

p) System Data: DER Generation Installation Charges

Section A.16. Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by the category in which they were incurred (including application, fees, metering, make ready, etc.).

For the calendar years 2020-2024, the following table shows the charges invoiced to members for the interconnection and installation of DER generation. The “Make Ready” costs continue to rise as greater penetration of DER on the system utilizes existing available capacity. As the existing available capacity for DER to back feed the distribution system is used up, additional costs to replace and/or augment the existing distribution facilities will continue to increase these costs.

Table 18. Total Charges to Members for DER Generation

Category	\$ Paid				
	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 ⁽¹⁾	\$870	\$7,417	\$15,348	\$18,043	\$20,305
Total	\$23,924	\$55,467	\$53,180	\$45,437	\$39,804

- (1) Make Ready costs only include the amount which was estimated and charged to the Member for the interconnection. Dakota Electric provides a fixed estimated cost for upgrades and any costs above this estimated amount are not charged.

q) Data: DER Generation System Total Capacity Interconnected

Section A.17. 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.).

For calendar years 2018-2024, the following are the aggregate nameplate capacity of the different DER generation systems that completed interconnected to Dakota Electric’s distribution system.

Table 19. Total Nameplate Capacity of DER Generation Interconnected by Year

Year ⁽¹⁾	Solar	Solar/Storage ⁽²⁾	Storage	Wind	Gas Engine	CHP
2018	2,406 kW	0	0	0	500 kW	0
2019	3,914 kW	0	5 kW	0	0	0
2020	1,035 kW	0	0	0	270 kW	0
2021	2,850 kW	0	40 kW	0	400 kW	0
2022	2,889 kW	0	51 kW	13 kW	0	0
2023	2,887 kW	0	62 kW	0	600 kW	0
2024	6,355 kW	0	13 kW	0	0	0

(1) 2018 includes a 2,000 kW solar installation. 2019 includes a 3,000 kW solar installation. 2024 includes a 4,500 kW solar installation.

(2) Solar/Storage column refers to DC coupled BESS that share inverter with the PV system. Given only a single inverter kW rating value, the total kW is included in the Solar column.

r) System Data: Number of DER Generation Systems Interconnected

Section A.18. 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.).

For calendar years 2020-2024, the following are the total number of DER generation systems, by type, that completed the interconnection process with Dakota Electric's distribution system.

Table 20. Number of DER Generation Systems Interconnected by Year

Year	Solar	Solar/Storage ⁽¹⁾	Storage	Wind	Gas Engine	CHP
2020	137	1	0	0	1	0
2021	366	1	4	0	1	0
2022	312	0	9	1	0	0
2023	346	1	6	0	1	0
2024	188	2	3	0	0	0

(1) Solar / Storage column refers to DC coupled ES that share inverter with the PV system.

s) System Data: Total DER Generation Systems Interconnected

Section A.19. 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.).

The table below reflects the number of DER generation systems interconnected to the distribution grid as of August 2025 and the total nameplate capacity of those units.

Table 21. Total Number of DER Generation Systems Interconnected

	Solar	Storage ⁽²⁾	Wind	Gas Engine	CHP
Quantity	1,695	31	10	119	0
Total Capacity kW	25,354	204	154	74,983 ⁽¹⁾	0

(1) Engine Prime Rating

(2) All the current storage projects are at existing solar installations, except for a single location.

t) System Data: Queued DER Generation Systems

Section A.20. 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.).

The following table reflects the number of DER generation systems in the interconnection queue as of October 1, 2023.

Table 22. Number of DER Generation Systems in Interconnection Queue

Solar	Solar/Storage	Storage	Wind	Gas Engine	Hydro	CHP
77	5	1	1	0	0	0

u) System Data: Total Electric Vehicles

Section A.21. Total number of electric vehicles in service territory.

Dakota Electric does not have visibility into all electric vehicles that are located within our service territory, but Dakota Electric does have special electric vehicle charging rates.¹⁹ On June 3, 2025, Dakota Electric filed its annual EV Informational Letter with the Commission in Docket No. E111/M-12-874. Based on the information in this letter, as of April 1, 2025, members have enrolled 1,876 plug-in electrical vehicles on Dakota Electric's EV charging rates.

Dakota Electric believes that around 42% of its members with EVs participate in one of the Cooperative's EV rates. Assuming 42% of EVs are on an EV rate, that would suggest approximately 4,471 EVs on the Dakota Electric system. This is similar to the 2024 EV numbers of 4,483 reported by the Commission in its annual EV report.

v) System Data: Public Electric Vehicle Charging Stations

Section A.22. Total number and capacity of public electric vehicle charging stations.

Dakota Electric is not informed about the installation of all electric vehicle charging stations within the service territory. The only exception is DCFC installations because these sites may require distribution system modification or upgrades. Since the last IDP Report, one DCFC installation has been installed in our service territory. One of the best resources where members can be directed to is the www.plugshare.com site which graphically shows electric vehicle charging station locations.

w) System Data: Battery Storage

Section A.23. Number of units and MW/MWh ratings of battery storage.

At the time this IDP report was filed, Dakota Electric is not aware of any battery storage units interconnected with the distribution system that export power. All the energy storage systems which have provided applications are being utilized for backup protection. Some of the energy storage systems are designed to support the entire home during an electrical outage, while others only support critical circuits during an outage. Another possible use of one

¹⁹ The approved two EV pilots for Dakota Electric in Docket No. E111/M-21-127. These pilots are for Commercial members and Multi-Family Residential members. In 2023, the Commission approved a virtual metered EV charging rate in Docket No. E111/M-22-592. These are in addition to Dakota Electric's TOU EV charging rate and EV charging that is available through our interruptible storage off-peak program.

or more of the battery energy storage systems is to support charging of the electrical vehicle from energy produced by the member's solar system.

It is important to note that there are many energy storage systems installed as uninterruptable power supply (UPS) systems. None of these traditional uses of energy storage have been involved in the current DER interconnection process; thus, the ratings and capacity of these systems have not been acquired or recorded. All the existing UPS systems are not designed to provide back feeding (export) to the distribution system, and they are also not capable of operating in parallel with the distribution grid. The UPS systems range from very small household back up battery systems, used to provide energy to personal computers, to very large battery systems which are used to provide energy to a data center for a brief period to bridge from the start of an outage until the backup generator can carry the electrical requirements. The charging of these energy storage devices is done during the time when the backup generator is supplying energy to the facility and thus does not negatively impact the distribution system.

As of October 2025, Dakota Electric has 40 battery energy storage systems which are interconnected with the distribution system. There are 11 systems which are in review or approved. Each of these systems are coupled with solar installations and are either DC or AC coupled, except for a single application where there is a battery only and no solar installation. Dakota Electric notes that as all the current interconnected BESS systems are member-owned and interconnected behind-the-meter, the ratings of the batteries are included in Section 5.s. Dakota Electric does not have any utility scale BESS systems interconnected.

x) System Data: Energy Efficient Program

Section A.24. MWh saving and peak demand reductions from EE program spending in previous year.

Dakota Electric's energy efficiency programs resulted in 15,382 MWh of savings in 2024.

y) System Data: Controllable Demand

Section A.25. Amount of controllable demand (in both MW and as a percentage of system peak).

The actual amount of demand available to control by Dakota Electric depends upon the season, weather, and many other factors. Later in Section 5.jj of this IDP Report, Dakota Electric provides detailed information about the amount of DER interconnected to the Dakota Electric system by substation and feeder. Within the IDP process, DER is defined to include controllable loads; as such, the information regarding the amount of connected controllable loads are listed in Section 5.jj.

The actual amount realized when the "control button is pushed" is different (lower) than the sum of the connected kW values. For each type of load, there are different factors impacting the actual amount of realized load reduction when the control button is pushed.

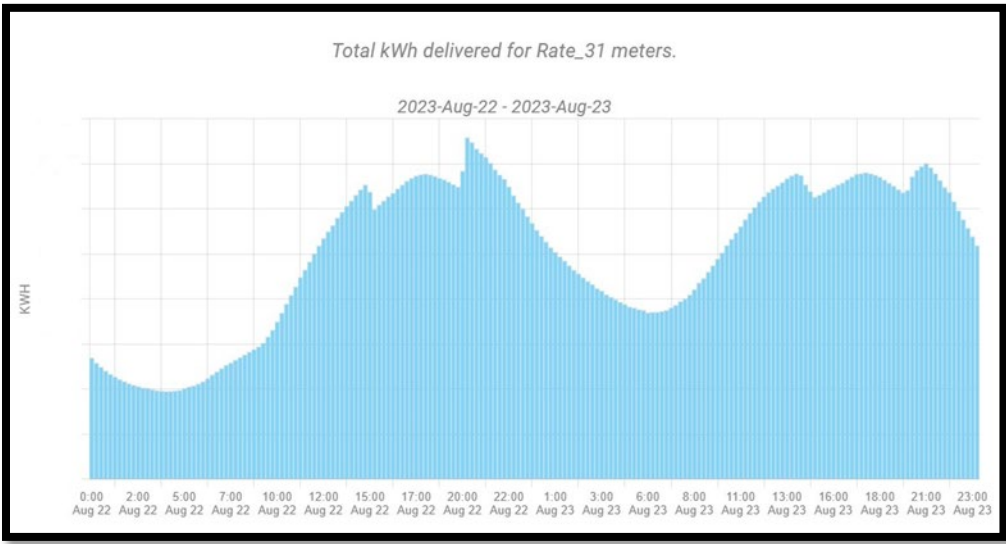
Air Conditioning

Air conditioning (AC) typically provides load reduction during summer months and, for any given day during this period, the number of AC units turned on will vary. For residential AC, Dakota Electric has observed that for some homes it can take one or two hot days, which heat up a home, before they use their AC unit. Generally, Dakota Electric observes a greater reduction in load during control summer months, which is mainly due to a higher overall demand amount in these months. Humidity and the number of hot days in a row will also affect the amount of AC run time, this is due to buildings retaining heat, which leads to members lowering the temperature in their homes. On a typical hot summer day, Dakota Electric forecasts approximately 10-25 MW of actual load reduction from controlling AC units. The amount of demand reduction per individual AC unit is decreasing as older units are

replaced with more energy efficient units. It is important to note that there is an implicit overall reduction in electrical demand from these newer units because they are more energy efficient.

The graph below shows energy usage during the August peaks. This graph includes all residential consumers, those who participate in load control, and those who do not. This graph shows the significant demand reduction achieved through the cooperation of our member owners. This graph below is a great example of the need for overall coordination. On the first day, Dakota Electric did not feather in the restoration of the load, which resulted in a high rebound peak demand on August 22. For the second day, August 23, Dakota Electric staggered in and out the load control in groups of homes to reduce the overall rebound peak demand during restoration.

Graph 18. Residential Demand Curtailment – August 2023 Peaks



Heat Pump

During the summer months (cooling periods), heat pumps operate the same as an air conditioner. During the winter months (heating periods), heat pumps operate just like during the cooling months except they heat a property. The main difference is that their run time is affected by the coldness of the ambient air. Dakota Electric projects between 2-8 MW of demand reduction from controlling heat pumps on a cold winter day. As more heat pumps are installed, Dakota Electric continues to work with the members to get those new units involved with the load control program.

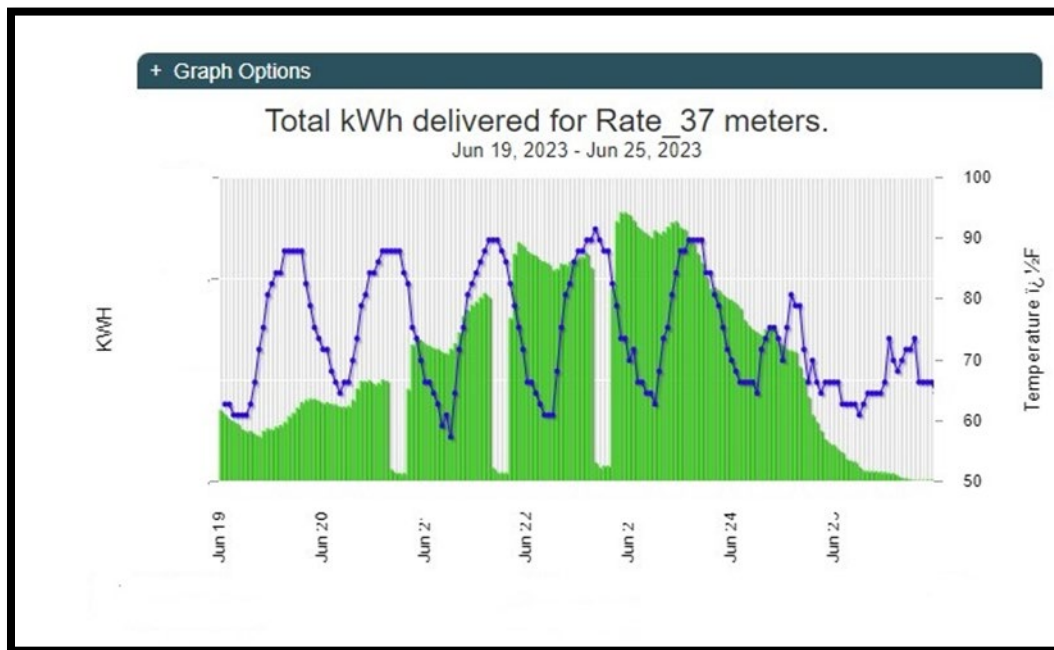
Heat Devices

Heating devices can include methods such as in-floor heating, electric strip heaters, or infrared heating. The use of these devices is variable as the heating device can be the main heat for a residence or supplemental heating for a room or garage. The expected load reduction is between 5-10 MW due to the variable use cases for these devices.

Irrigation

Irrigation is primarily used for agriculture purposes and is configured to allow Dakota Electric to shed these loads during peak load periods. As with other loads, irrigation usage is dependent upon the weather, so available load control is variable. In some instances, there is minimal load reduction from irrigation, such as just after a rain event, while in other instances there can be between 8-12 MW of load reduction. It is important to note that Irrigation is often used to distribute nutrients to the crops and may be operated even in naturally wet conditions. The graph below shows the control of the irrigation systems on the Dakota Electric system during June 2023. The impact of load control is evident in the solid drop in the electrical demand associated with each control.

Graph 19. Irrigation Curtailment on Days with Load Controls



Miscellaneous and Water Heat

The miscellaneous category includes items such as hot tubs and other electric appliances. Water Heat is a combination of peak shaved water heaters and off-peak water heaters. Peak shaved water heaters are controlled for a few hours each control period. Off-peak water heaters only heat water during the nighttime (off-peak) hours. There is over 30 MW of connected load in these categories. Depending upon the season, and the time of day, the amount of load reduction available from this category is between 5-10 MW.

C&I Interruptible Genset

This category includes member-owned generation systems where the entire building's electrical load is seamlessly transferred from the distribution system to the member's generation system. This control category is only available to Dakota Electric's larger commercial and industrial members. The load (kW) values in this category are actual summer peak demand values from the member's meter. These numbers do not reflect the total capacity of the member generation. The load (kW) values listed in this category are closer to the actual load reduction that is expected. The difference between the total number in this category and the actual load reduction experienced is due to the members' peak load not being coincidental with the control period. For a typical hot summer day, the C&I Interruptible generators can shed between 50-65 MW of load from the system. During the winter, the amount of load reduction from this category is a bit lower due to lower overall electrical demands.

Curtailment

This category is the maximum estimated amount of load that commercial members have contracted to shed from the distribution system during system load control periods. The commercial members who are on this program contract to shed their electric demand down to a pre-determined level (PDL). The amount listed is the difference between the PDL and the actual monthly peak kW demand. For this category approximately 2-5 MW of actual load reduction is expected.

Total Load Control

Table 36 provides a summary of the number of units and available, potential load control associated with the categories and programs discussed above.

Table 23. 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
Curtailement	24	9	2-5	2-5

The load reduction numbers listed above are estimates. The actual amount of load reduction during any control period is variable and driven by many factors including: season, time of day, weather (especially the temperature and humidity, both the day of the control period and the weather on the days preceding the control period), and length of control period. During a very hot mid-summer weekday, Dakota Electric is typically able to shed 80-100 MW's of electrical demand.

z) Financial Data: Distribution System Spending IDP Budget Categories

Section A.26. A high-level look at historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future in each category listed below.

- 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. Grid Modernization and Pilot Projects*
- e. New Customer Projects and New Revenue*
- f. Projects related to local (or other) government-requirements (road-relocations, etc.)*
- g. Metering*
- h. Other*

The table below shows Dakota Electric's capital spending for construction over a historical 5-year period (2020-2024) and projected 5-year period (2025-2029) by the IDP specific categories. The capital projects included in this table are only projects related to the distribution system. For example, projects related to maintenance of our corporate building or internal software projects are excluded from these construction capital projects.

As previously explained in the 2021 and 2023 IDP Reports, Dakota Electric does not track construction projects using the categories requested in the list at the beginning of this section. At Dakota Electric, a code is applied to the construction work order which corresponds to the type of construction activity. For example, projects associated with new services are part of the 100 series codes, new or modified main lines are 200 and 300 series, respectively, and substation work is the 700 series. Dakota Electric uses these classifications for budgeting and project cost tracking. Dakota Electric's work order and financial procedures track "what" was built versus "why" the project was initiated. Dakota Electric appreciates the Commission and Staff for modifying this filing requirement to allow this

data to be categorized into a ‘high-level’ look at distribution spending. For the 2025 IDP Report, Dakota Electric has reconfigured some of the codes and budget categories. This may cause an increase or decrease in some categories versus how costs were previously attributed to each category in past IDPs. Years 2020, 2021, and 2022 have not changed from what was reported in the 2023 IDP. The table below is an estimate of the breakdown for the requested categories using the actual total capital spending over the most recent 5 years.

Table 24. Historical and Projected Capital Spending - IDP Specific Categories

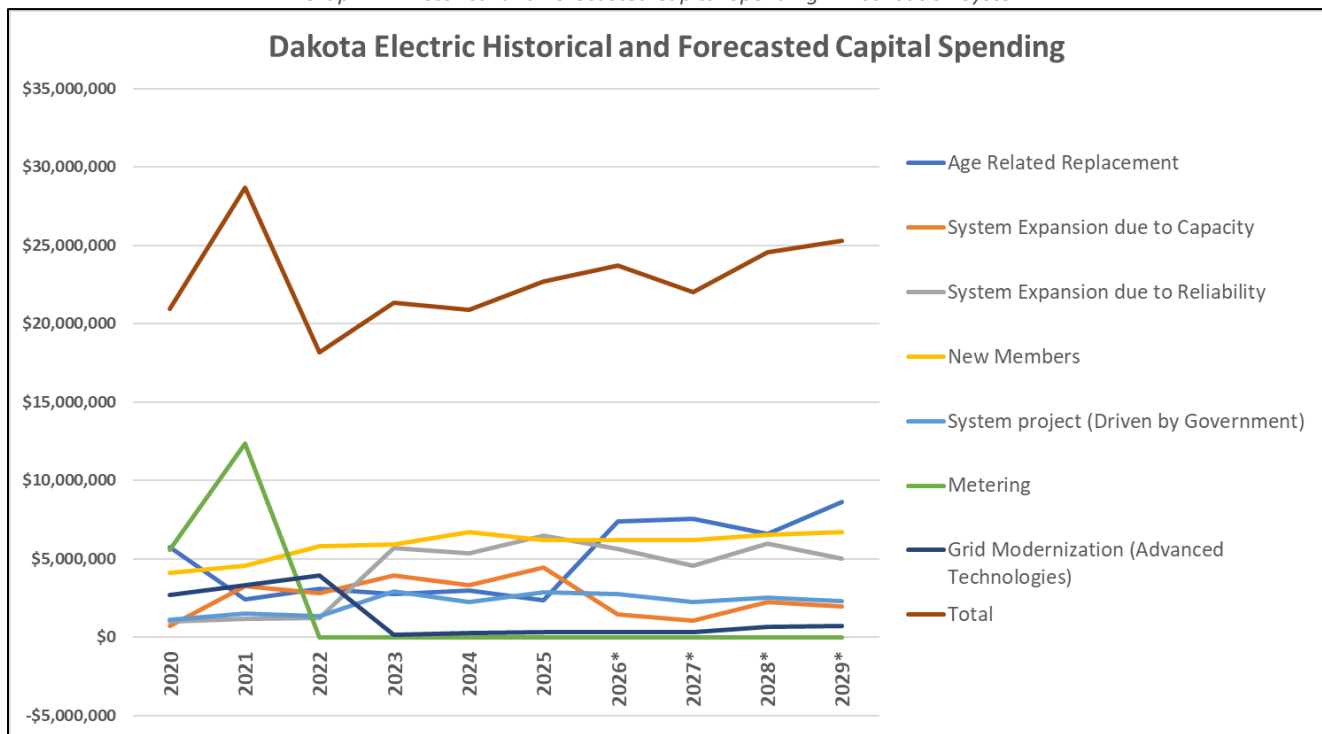
	2020	2021	2022	2023	2024		2025	2026	2027	2028	2029
Age Related Replacement	\$5,771	\$2,426	\$3,108	\$2,776	\$3,006		\$2,332	\$7,376	\$7,578	\$6,623	\$8,628
System Expansion (Due to Capacity)	\$694	\$3,263	\$2,772	\$3,925	\$3,301		\$4,469	\$1,438	\$1,079	\$2,229	\$1,938
System Expansion (Due to Reliability)	\$1,025	\$1,176	\$1,225	\$5,692	\$5,341		\$6,461	\$5,616	\$4,549	\$5,993	\$4,992
New Members	\$4,099	\$4,561	\$5,782	\$5,891	\$6,695		\$6,218	\$6,218	\$6,218	\$6,540	\$6,708
System Project (Driven by Mandate)	\$1,107	\$1,532	\$1,659	\$2,935	\$2,259		\$2,889	\$2,743	\$2,254	\$2,530	\$2,300
Metering	\$5,592	\$12,381	\$0	\$0	\$0		\$0	\$0	\$0	\$0	\$0
Grid Modernization (Advanced Technologies)	\$2,685	\$3,348	\$3,950	\$141	\$271		\$339	\$339	\$328	\$663	\$729
Annual Total	\$20,972	\$28,687	\$18,495	\$21,361	\$20,875		\$22,708	\$23,730	\$22,006	\$24,578	\$25,295

i) All dollars are in Thousands.

ii) Years 2020-2024 are actual capital spent. Years 2025-2029 are projected capital spend.

The forecasted amounts in the above table are current as of October 2025. It is important to note that these amounts may change because the budget process for 2025 is open and has not yet been reviewed, and approved, by the Dakota Electric Board. Dakota Electric also notes that it has submitted projects for grant funding. Grant-related projects have not yet been finalized, or awarded, and are not included in the above table.

Graph 24. Historical and Forecasted Capital Spending – Distribution System



aa) Financial Data: Distribution Spending Dakota Electric Budget Categories

Section A.27. Historical distribution spending for the past 5-years and projected distribution system spending for 5-years into the future broken down by Dakota's internal distribution budget categories, itemizing and non-traditional distribution projects.

As noted in sections above, Dakota Electric appreciates Commission Staff for modifying this filing requirement to allow Dakota Electric to report capital spending and budget based off internal categories Dakota Electric provides a discussion of the internal budget categories below.

New Consumers and Service Rebuilds: This category includes all costs related to residential developments, residential & commercial line extensions, and service rebuilds. It also includes the service connect and installation of metering costs. Dakota Electric is forecasting a large increase in 2026 mainly attributed to a single new large commercial member. In years 2027-2029, Dakota Electric is forecasting a more standard yearly cost based off historical costs for new residential developments, line extensions, and commercial services.

Mainlines: This category includes all costs related to mainline line rebuilds or new mainlines. This includes road relocation projects, reconductoring projects, and system reliability projects such as converting mainline from overhead to underground. Dakota Electric is forecasting slightly above average for mainline projects for the next 5 years mainly due to an increase in road relocation projects in our service territory and due to new member growth. Additionally, there are some mainline projects identified to provide enhanced reliability for contingency switching in some areas.

System Improvements: This category includes all costs related to system replacements. Replacement equipment includes poles, transformers, cable replacement, meter replacements, and backlot overhead to underground replacements. Dakota Electric is forecasting additional spending in this category due to increased costs of

equipment. By the end of 2025, Dakota Electric is planning to have all unjacketed underground cables on the distribution system replaced. This has been a significant 30 plus year effort, and Dakota Electric's reliability numbers illustrate the benefits of this long-term initiative and the associated investments. In the coming years, Dakota Electric is planning to continue with our robust investments in reliability by changing the Cooperative's focus to strategic undergrounding, which includes targeting residential developments that are currently served from backlot overhead lines and relocating to front lot underground. Additionally, Dakota Electric has increased the budget to start proactively replacing aging overhead lines and poles which are over 60 years old.

Substations: This category includes all costs related to Substations. This includes land purchases and everything inside of a substation, (e.g., substation transformers, switchgear, ground grid, fencing). Substation projects are one of the few projects that must be planned beyond the standard year-ahead time frame. New substations require permitting and interconnection with transmission and typically have a lead time of 3-5 years from initial planning to completion. Some pieces of substation equipment, such as the substation transformer, have longer lead times and must be specified and procured for a specific substation project. Individual substation projects are normally the largest single capital project within the annual capital budget and, necessarily, have the greatest impact upon the total budget. Over the next few years, Dakota Electric will be replacing older substation equipment which is reaching the end of life. Most equipment, including substation equipment, is designed for 30-40 years of reliable service. As shared at the stakeholder meetings, over 30% of the Dakota Electric distribution substations are considered "senior" or substations near their end of useful life. Ten substation transformers are over 40 years old and one more are over 30 years old. In addition, there are seven substations that have switchgear over 40 years old. As equipment ages, the risk of failure increases, and this risk rapidly increases as the equipment is at the end of life. Historically, getting replacement transformers or switchgear in a short time was possible. However, with lead times for substation equipment changing from several months to several years, the risk of long-term outages resulting from substation equipment failures has become unacceptable. In light of these concerns, Dakota Electric has embarked upon a series of projects to rejuvenate aging substations. Transformers and/or switchgear at these substations which were constructed in the 1970's and 1980's are scheduled for replacement. Estimated expenditures for these projects are included in this budget category.

Distribution Equipment and Automation: This category includes all costs related to replacement of distribution equipment. Distribution Equipment includes, but not limited to: Sectionalizing devices (Fuses, Reclosers), Voltage Regulators, Mainline Switches (overhead and pad mounted), Capacitor Banks, and Streetlights. This category also includes automation devices such as SCADA devices, load management devices, DER monitoring devices, and other remote operated equipment. Note: Typically, new distribution equipment, such as mainline switches, will be included within a mainline or new consumer work order meaning that their costs will be included in their associated budget category.

Each year, during the budget cycle, capital dollars for reliability and age-related replacement projects are generally identified but specific projects are not. Actual projects are based upon historical reliability performance, and the worst performing sections of line are targeted for replacement. The group in charge of these projects is given a spending budget and then decides which sections of the system are replaced. This category is affected annually by the number of other identified projects in the capital budget, such as expected new services and government mandated projects. However, Dakota Electric has identified a specific project to replace about 100 fuse cabinets over the next 5 years. This project was identified because previous suppliers are no longer producing the specific fuse cabinets that Dakota Electric historically installed. Dakota Electric found a new supplier to manufacture the fuse cabinets and plans to replace them all over a multi-year period.

Salvage: This category includes all costs related to the removal of equipment from the field which can be salvaged back into inventory and re-used in the future. This category is generally a negative budget as it is related to

removing plant, and associated dollars, from the field which can go back into service on a different project. Dakota Electric budgets a standard amount of salvage value each year based off historical averages, but this category is highly subject to change depending on the projects that happen in other categories and what equipment can be salvaged.

Grid Modernization: This category is specifically related to the AGI implementation project. Dakota Electric expects future costs in maintaining the AGI system and metering components, but these costs have been located under the Distribution Equipment and Automation category in the forecasted years.

Contribution in Aid of Construction (CIAC): This category is related to line extension costs that members are required to pay prior to construction for a new line extension or service rebuild. Line extension costs are calculated based off Dakota Electric Rate book. Dakota Electric budgets CIAC based off historical averages and takes into account any known projects in the upcoming years.

It is important to note that Dakota Electric does not initiate the construction of new facilities until new load requires new distribution capacity. Therefore, while there are forecasted dollars in categories such as new members or mainlines, the actual dollars spent will depend upon the actual need for distribution system capacity changes. The numbers for these categories are based on Dakota Electric’s forecasted growth expectations.

The table below shows Dakota Electric’s capital spending for construction over a historical 5-year period (2020-2024) and projected 5-year period (2025-2029) by Dakota Electric’s internal budget categories. Dakota Electric’s Board of Directors approves Dakota Electric’s capital workplan which is done annually using a 3-year rolling budget. The capital projects included in this table are only projects related to the distribution system. For example, projects related to maintenance of our corporate building or internal software projects are excluded from these construction capital projects.

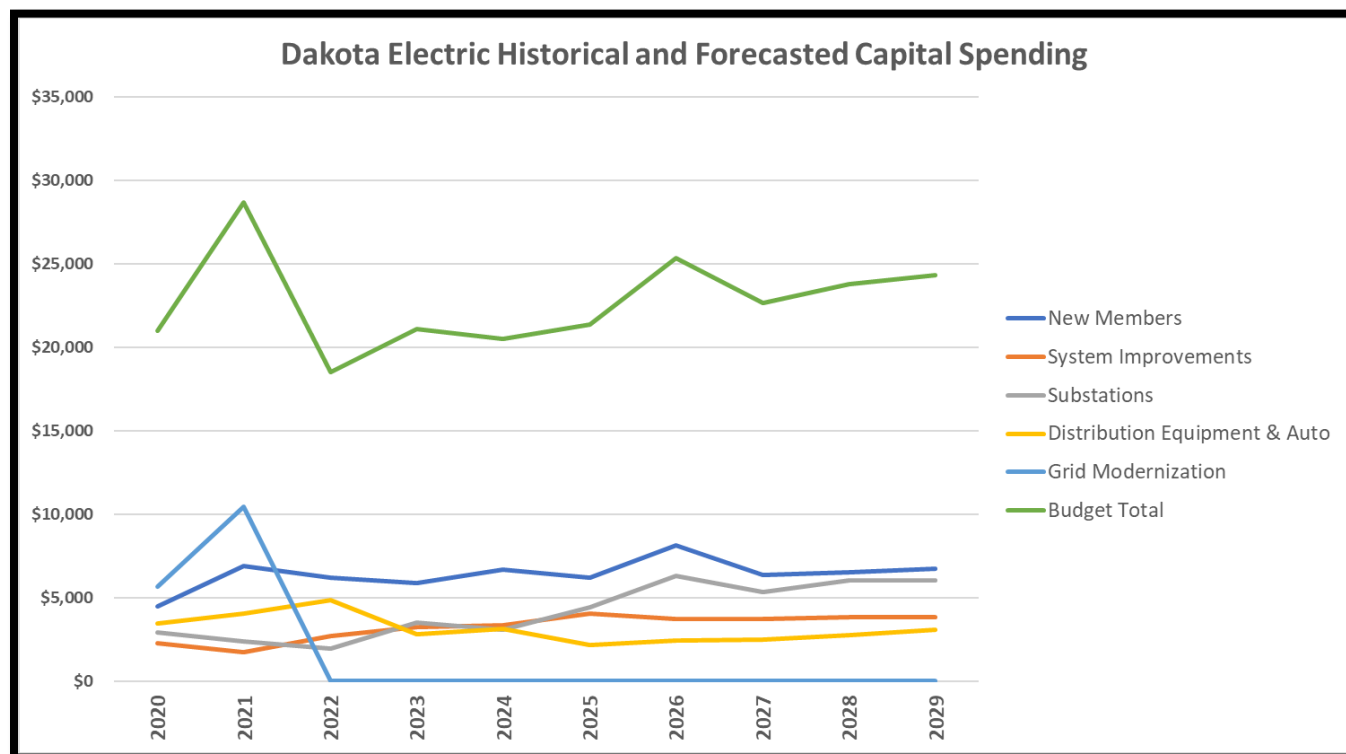
Table 25. Historical and Projected Capital Spending – Dakota Electric Categories

	2020	2021	2022	2023	2024		2025	2026	2027	2028	2029
New Members	\$4,456	\$6,904	\$6,218	\$5,891	\$6,696		\$6,218	\$8,118	\$6,376	\$6,540	\$6,708
Mainlines	\$2,434	\$3,300	\$3,134	\$5,870	\$4,519		\$4,781	\$5,043	\$4,987	\$4,922	\$4,968
System Improvements	\$2,281	\$1,734	\$2,693	\$3,257	\$3,320		\$4,054	\$3,704	\$3,705	\$3,805	\$3,805
Substations	\$2,937	\$2,391	\$1,932	\$3,511	\$3,103		\$4,435	\$6,305	\$5,325	\$6,025	\$6,025
Distribution Equipment & Auto	\$3,472	\$4,046	\$4,825	\$2,833	\$3,123		\$2,175	\$2,425	\$2,507	\$2,742	\$3,070
Salvage	(\$276)	(\$110)	(\$312)	(\$290)	(\$291)		(\$280)	(\$280)	(\$280)	(\$280)	(\$280)
Grid Modernization	\$5,668	\$10,417	\$0	\$0	\$0		\$0	\$0	\$0	\$0	\$0
Budget Total	\$20,972	\$28,682	\$18,490	\$21,072	\$20,470		\$21,383	\$25,315	\$22,620	\$23,754	\$24,296
CIAC	(\$1,695)	(\$3,058)	(\$2,572)	(\$2,417)	(\$2,441)		(\$2,515)	(\$4,535)	(\$2,635)	(\$2,635)	(\$2,635)
Net Total	\$19,277	\$25,624	\$15,918	\$18,655	\$18,029		\$18,868	\$20,780	\$19,985	\$21,119	\$21,661

i) All dollars are in Thousands.

ii) Years 2020-2024 are actual capital spent. Years 2025-2029 are projected capital spend.

Graph 25. Historical and Forecasted Capital Spending – Distribution System



The forecasted amounts in the above table are current as of October 2025. It is important to note that these amounts may change because the budget process for 2025 is open and has not yet been reviewed, and approved, by Dakota Electric’s Board. Dakota Electric also notes that it has submitted projects for grant funding. Grant-related projects have not yet been finalized, or awarded, and are not included in the above table.

bb) Financial Data: Investments in Distribution System Upgrades

Section A.28. All non-Dakota Electric 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).

Dakota Electric reviewed this filing requirement, and it appears to specifically request information on non-Dakota Electric investments made as required for interconnection of a DER. This is typically known as “make ready costs.” Dakota Electric has provided make-ready costs in the table provided under Section 5.p. Dakota Electric is unsure if the information below is useful or needed and requests that the Commission clarify this filing requirement for future IDPs.

The table below shows all the Contribution-In-Aid-of-Construction (CIAC) collected by Dakota Electric for each of the requested areas over the period 2020-2024. Dakota Electric does not track CIAC costs by feeder or substation. The amount of CIAC collected is dependent upon the type of projects requested. The information in the table below shows that CIAC for the new member category was highest in 2024, and it was significantly higher than the prior two years. These significantly higher CIAC costs were primarily due to increased payments from new residential developments and larger street lighting projects. As shown in the table below some of the categories which normally had zero CIAC now has some. For the 2025 IDP Report, Dakota Electric has reconfigured some of the codes and budget categories. This may cause an increase or decrease in some categories versus how costs were previously attributed to each category in past IDPs.

Table 26. Historical Contribution-In-Aid-of-Construction

	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

i) All dollars are in Thousands

cc) Financial Data: Planned Distribution Capital Projects

Section A.29. Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should align with Dakota's internal distribution budget categories.

After the discussion at the Commission Staff's stakeholder meeting regarding modifications to financial budget reporting, it was determined that there is no minimum threshold figure for this reporting requirement. Dakota Electric is using a new threshold of \$500,000 to define a project for inclusion in this listing. With the significant increases in material costs, this new threshold has been established to avoid a long list of projects and to allow us to focus the review on only the largest dollar capital projects. In following the filing requirement, these projects have been categorized into Dakota Electric's internal budget categories.

As discussed in other sections of this report, Dakota Electric does not generally commit to projects beyond a year, except for projects (e.g., substations) which have longer permitting time or require equipment with longer lead times. Additionally, it is important to note that the list of projects is subject to change as the capital construction budget for 2026-2028 has not been approved by the Board of Directors. Dakota Electric's planned projects include what has not yet been completed in 2025 and what is proposed for 2025-2029.

New Members:

Project NOVA, Eagan – A new large commercial member which requires significant rework of Dakota Electric's mainline feeders is currently under construction. The project is estimated to be \$1.9 million and will be completed in 2026. Dakota Electric will be receiving a large CIAC for this project.

Project Oppidan, Eagan – A new large commercial member will be developing a new facility in Dakota Electric's service territory. The project is estimated to be \$800,000 and will be completed in 2026. Dakota Electric will be receiving a large CIAC for this project.

There may be additional individual new member projects that cost greater than \$500,000 but Dakota Electric is unaware of any additional at this time.

Mainlines:

Feeders for Lakeville Substation - To integrate the new Lakeville substation expansion with the distribution system, new circuits (feeders) are being installed. The substation will have 4 new feeders which will be supplying power to the area. The new feeders are being installed underground and use large capacity 750 MCM cables. The total 2025 budget for these feeders is \$1.3 million. These feeders are being installed and will be energized by the end of 2025.

Road Rebuild – Dakota County 91 – Dakota Electric and Great River Energy have been requested to rebuild the existing transmission lines, which has Dakota Electric distribution lines joint attached to the transmission poles, farther away from the road as the road is being rebuilt with increased ROW. Since the existing line is within an easement, compensation for this project will be received from the County. The capital cost for the distribution under build portion of this 1.9 mile rebuild is \$560,000. This project is expected to be completed in 2025.

Road Rebuild – MnDOT Highway 50 – MnDOT is rebuilding highway 50 from highway 52 East through the town of New Trier for a total of approximately 7 miles. The project includes cutting and filling grade alongside the roadway and a requirement for Dakota Electric to relocate our existing overhead lines further away from the road in the expanded MnDOT ROW. This will be a significant project for Dakota Electric that will begin in 2026. The cost estimate for this project is \$1.5 million.

Substations:

Increase Capacity at Lakeville Substation - In 2025, the Lakeville substation is planned to have a second transformer and switchgear installed to increase the capacity of the substation. \$2.5 million is forecasted for this work. The driver for this expansion is new residential and commercial development in eastern Apple Valley and northeastern Lakeville.

Dakota Heights Substation Switchgear Replacement - The substation switchgear at Dakota Heights has experienced multiple failures of the feeder breakers over the years. These breakers were installed worldwide in the 1980s with a concentrated amount installed in Europe. Utilities in the United States did not purchase and install a large number of these units. The breakers are well known for poor reliability, but with few installed in the United States, there are no spare replacement parts or units available. Dakota Electric has reviewed the options and, given the switchgear is already over 35 years old, replacement of the switchgear is considered the most cost-effective solution. This will also provide improved long-term reliability and employee safety. The switchgear replacement is scheduled for 2025, and the cost is estimated at \$1.475 million.

Fischer Substation Rebuild - The Fisher Substation in Apple Valley was built around 1980 and the transformer and switchgear are now over 40 years old. Dakota Electric has initiated a substation rejuvenation project, and the replacement of the two transformers and switchgear will be one of the first substations being targeted. The project is scheduled for 2026, and the cost is estimated at \$5.6 million.

Empire Substation Switchgear Replacement - The substation switchgear at Empire has breakers that were installed worldwide in the 1980s with a concentrated amount installed in Europe. Utilities in the United States did not purchase and install a large number of these units. The breakers are well known for poor reliability, but with few installed in the United States, there are no spare replacement parts or units available. Dakota Electric has reviewed the options and, given the switchgear is already over 35 years old, replacement of the switchgear is considered the most cost-effective solution. This will also provide improved long-term reliability and employee safety. The switchgear replacement is scheduled for 2026, and the cost is estimated at \$1.5 million.

Pilot Knob Substation Switchgear Replacements - The substation switchgear at Pilot Knob has breakers that were installed worldwide in the 1980s with a concentrated amount installed in Europe. Utilities in the United States did

not purchase and install a large number of these units. The breakers are well known for poor reliability, but with few installed in the United States, there are no spare replacement parts or units available. Dakota Electric has reviewed the options and, given the switchgear is already over 35 years old, replacement of the switchgear is considered the most cost-effective solution. This will also provide improved long-term reliability and employee safety. In addition, the site owner Great River Energy is rebuilding part of the substation as well. The switchgear replacement is scheduled for 2027, and the cost is estimated at \$1.5 million.

Burnsville Substation Rebuild - The Burnsville Substation in Apple Valley was built around 1980 and the transformer and switchgear are now over 40 years old. Dakota Electric has initiated a substation rejuvenation project and the replacement of the two transformers and switchgear. The project is planned for 2027 construction for one unit and 2028 construction for the second unit. In addition, the site owner Great River Energy is rebuilding part of the substation as well. The cost is estimated at \$6.0 million.

Colonial Hills Substation Rebuild - The Colonial Hills Substation was built around 1980, and the transformer and switchgear are now over 40 years old. Dakota Electric has initiated a substation rejuvenation project, and the replacement of the two transformers and switchgear will be one of the substations targeted. The project is planned for 2029 construction, and the cost is estimated at \$6.0 million.

New or Relocated Substation – Dakota Electric has secured a manufacturing slot for an additional transformer in 2028 or 2029. This slot has been secured due to supply chain and procurement constraints, but Dakota Electric has the option to delay or decline the slot prior to manufacture. Dakota Electric has identified an aging substation that is due for replacement or rejuvenation. Depending on organic load growth and forecasted load growth over the next few years, Dakota Electric may elect to relocate this substation location. Further analysis is needed to review determine the preferred location in relation to the capacity requirements. A non-wires alternative will be considered for this replacement, possibly for the 2027 IDP, but Dakota Electric is unsure of the timeline related to this substation. Dakota Electric is considering a 2028-2029 timeline for replacement. The estimated cost \$3 million.

System Improvement:

Old Pole Replacement/Line Rebuilds - As part of a continuing project, Dakota Electric is rebuilding overhead lines where the wooden poles are nearing or are over 60 years old. From historical pole testing, it was clear that wooden poles over 60 years old have reached the end of their useful life. Several years ago, a plan to proactively identify and replace overhead lines which have a majority of their poles 60 years of age or older was initiated. In 2025-2029, \$800,000 is being allocated to these projects. As part of these overhead pole line replacements, the capacity of the existing line is reviewed to see if upgrading the capacity is needed to support the future load estimates for the area. As a result, for some of these projects, the existing line is replaced with a larger capacity line. The driver for these projects has several reasons: age related, reliability related, and capacity related.

Distribution Equipment and Automation:

Single Phase Fuse Cabinet Replacements - Dakota Electric has identified a specific project to replace about 100 fuse cabinets over the next 5 years. This project was identified because previous suppliers are no longer producing the specific fuse cabinets that Dakota Electric historically installed. Dakota Electric found a new supplier to manufacture and plans to replace all the fuse cabinets from 2026-2029. The annual budget for this project is approximately \$600,000.

dd) Financial Data: Cost Benefit Analysis - Non-Traditional Dist. System Solution

Section A.30. 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.

For over 30 years, Dakota Electric has used load management to help manage its system peak demands and reduce the demand charges from its power supplier. Load management solutions reduce demand during peak load period and are also available to reduce system demand during system contingencies. Dakota Electric's proactive use of load management has saved members millions of dollars since their inception and currently represents an over \$15 million saving per year, not including additional savings such as avoided generation. Furthermore, the reduced demand associated with energy efficiency has allowed Dakota Electric to defer or eliminate the need to construct additional distribution resources.

ee) DER Deployment: Current DER Deployment

Section A.31. 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 B – DER Feeder Summary Report provides a list, by substation and feeder, of existing DER deployment as of August 2025. The listing is by type and overall kW. Aggregate numbers have been provided in the table below for ease of reference. Appendix B includes additional information.

Table 27. Current DER Deployment

Type	Quantity	kW ⁽²⁾
Standard ⁽¹⁾	119	74,983
Solar	1,695	25,353.9
Wind	10	154
Storage	31	203.8

(1) A 'Standard' DER is a natural gas or diesel generator that is connected to Dakota Electric's rate 70 interruptible service program.

(2) kW is the full AC nameplate capacity of DER.

The values provided for the load control receiver loads are based upon information gathered during the initial load control receiver installation and do not include reductions in these kW control values due to replacement of the appliance with a more efficient unit. The actual amount of load control is less than the sum of these load control receiver loads values as these numbers are not diversified and assume that all controlled devices are running 100% of the time. As previously discussed, the actual available load control value is dependent upon the current weather, season, and other factors.

Dakota Electric's distribution system is considered, and operated as, one planning area and is maintained by a single service/work center located in Farmington, Minnesota.

ff) DER Deployment: High DER or Electrification Penetration

Section A.32. Information on areas of existing or forecasted high DER and/or electrification penetration. Include definition and rationale for what the Company considers "high" DER and electrification penetration.

Dakota Electric does not have any areas which it believes are considered "high" behind the meter DER penetration and does not have any areas forecasted to have high levels of behind the meter DER penetration. DER penetration is

considered high by Dakota Electric when it is unable to add additional small behind the meter DER without expensive upgrades of the distribution system.

Dakota Electric has not developed a definition or rationale for which it believes would be considered “high” electrification penetration. Dakota Electric has done some engineering studies regarding electric vehicle penetration and believes the system will be able to accommodate multiple EVs on a transformer, depending on size and number of homes. With the newly installed AGI system, Dakota Electric has the ability to more closely monitor system loading which likely will shape the definition and rationale for which is considered “high” electrification penetration over the future years.

gg) DER Deployment: Areas with Abnormal Voltage or Frequency

Section A.33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.

Dakota Electric has not encountered issues with extended abnormal voltages due to the operation of DER systems. There has been one service location in 2025 that has consistently seen higher than normal voltages on the member end when operating DER. The issue has not extended up to the medium voltage distribution level and is isolated on the secondary side of the members’ service. Dakota Electric is currently working with the member to mitigate this issue. With the limited penetration levels of DER installations on our system, most of the Dakota Electric distribution system still has load levels which are significantly greater than the total DER generation levels. There are, however, a few feeders where the large DER generation is greater than the native load. Dakota Electric believes the advanced inverter settings will help to reduce the chance of high voltage due to the operation of DER generation systems.

Frequency is regulated by the Eastern Interconnection, and is maintained at the transmission level, Dakota Electric does not have any areas with existing or forecasted abnormal frequency.

hh) DER Deployment: System Upgrades for Electrification

Section A.34. Information on distribution upgrades made to accommodate electrification, when known, including whether if was reactive to new load or based on a short-term forecast.

Dakota Electric has not made distribution system upgrades specifically made to accommodate electrification. Dakota Electric has made system upgrades for new members, but these are generally new mainline extensions or mainline rebuilds specifically because of the size of the new load, not specifically due to electrification. Dakota Electric has modified planning & design standards for new residential developments to have less homes on a single transformer as these newer homes are now being built with electric vehicles and additional electrification in mind. Dakota Electric continues to monitor design standards and review system loading which may require upgrades due to electrification.

ii) DER Deployment: Fuel-Switching Rebates

Section A.35. Number of fuel-switching rebated granted through Dakota Electric’s Energy Conservation Optimization (ECO) plan in the prior year, broken out by technology type (air/ground source heat pump, water heater, cooking, other industrial process heat, electric vehicles, etc.)

Below is a table with the number of fuel-switching rebates granted by Dakota Electric in 2024.

Table 28. Fuel-Switching Rebates by Technology Type

Technology Type	Quantity
Ground source heat pumps	12
Ducted air source heat pumps	285
Ductless air source heat pumps	65
Heat pump water heaters	31
Electric water heaters	55
Electric Vehicles	427

jj) DER Deployment: Load Management Program Participants

Section A.36. Number of electric space or water heating devices enrolled in a time-of-use rate or demand response program broken out by program type.

Below is a table with the number of load management participants broken out by type.

Table 29. Load Management Enrollment by Type

Program	Number of Units
Air Conditioning	44,098
Heat Pump	2,809
Heat Device	3,291
Irrigation	394
Miscellaneous ⁽¹⁾	596
Water Heat ⁽²⁾	7,217
C&I Interruptible Generation	119
Curtailement	24
Electric Vehicle TOU ⁽³⁾	1479
Electric Vehicle Storage ⁽³⁾	709
Virtual Metered Electric Vehicle	26

(1) The miscellaneous category includes items such as hot tubs and other electric appliances.

(2) Water Heat is a combination of peak shaved water heaters and off-peak water heaters.

(3) There may be multiple electric vehicles on a single service that are only counted as a single unit as they may be connected to the same off-peak meter.

Appendix A – Sub & Feeder Minimum Load Information January 2024 – December 2024

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
Bvillesby (2)	Substation	3,858	3,661	3,531	644	539	535	686	699	647
	1				22	54	73	22	54	77
	2				32	35	34	38	47	44
	3				186	141	133	216	152	146
	4				92	125	109	109	125	124
Hastings (3)	Substation	9,270	10,665	11,257	1,664	1,684	1,707	1,664	1,978	2,211
	1				1,167	1,111	1,077	1,468	1,412	1,466
	2				39	44	59	39	44	59
	3				162	161	232	167	178	232
	4				180	188	181	228	220	221
Castle Rock (4)*	Substation	2,917	3,028	3,445	740	555	549	751	728	749
	1				81	99	56	118	99	76
	2				7	33	68	7	33	68
	4				454	308	256	463	429	289
Burnsville North (5)	Substation	24,974	25,985	32,736	5,721	6,231	5,950	7,475	8,385	7,859
	1 (N)				348	1,031	526	355	1,193	526
	3 (N)				854	880	950	1,094	1,060	1,270
	5 (N)				661	509	139	765	623	139
	7 (N)				1,320	1,529	1,558	2,077	1,956	1,901
	9 (N)				849	824	253	1,110	934	319
	11 (N)				857	685	786	1,073	685	1,108
Burnsville South (5)	Substation	23,774	24,414	22,893	5,716	3,917	5,565	7,860	5,141	7,564
	2 (S)				1,170	203	449	1,233	300	449
	4 (S)				1,234	1,209	1,141	1,517	1,667	1,572
	6 (S)				1,766	351	1,608	2,254	374	2,034
	8 (S)				438	425	419	577	529	554
	10 (S)				271	262	275	333	349	375
Eagan (6)	Substation	8,863	9,571	10,103	2,065	2,027	1,731	2,183	2,542	2,418
	1				482	228	264	539	676	264
	2				136	139	210	136	139	250
	3				79	143	10	79	229	106
	4				360	358	353	372	401	448
	5				245	273	364	245	273	477
	6				149	95	113	149	95	217
Miesville (7)	Substation	6,357	6,694	6,919	1,175	1,266	1,240	1,175	1,323	1,431
	1				107	115	38	117	115	41
	2				249	293	296	351	354	382
	3				97	107	106	97	122	106
	4				146	165	169	146	165	169
	5				130	329	38	130	329	41
Orchard Lake (8)	Substation	18,703	22,619	20,017	4,762	4,731	4,322	5,957	5,761	5,949
	1				660	661	608	717	771	749
	2				393	752	791	393	956	973
	3				1,137	1,110	965	1,572	1,525	1,100
	4				281	344	71	349	372	71
	5				144	71	8	195	89	12
	6				847	806		868	1,148	

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
River Hills East (9)	Substation	12,898	12,058	12,966	2,789	2,850	2,817	3,353	3,216	4,049
	2				3,353	806	824	862	1,108	1,148
	3				295	318	110	295	337	395
	4				990	995	1,003	1,265	1,422	1,359
	8				365	375	320	513	579	459
	10				246	252	261	341	349	385
River Hills West (9)	Substation	10,919	11,824	11,849	2,536	2,601	2,644	3,098	3,421	3,471
	1				410	478	298	676	478	756
	5				721	775	653	721	1,033	653
	6				720	708	756	1,047	919	1,051
	7				383	411	12	529	533	117
Yankee Doodle North (10)	Substation	14,802	13,942	12,141	3,656	3,866	3,632	3,881	4,163	4,100
	1				765	841	849	795	1,197	879
	3				582	639	625	582	828	828
	5				1,094	1,355	940	1,094	1,379	940
	7				274	405	324	318	734	541
Yankee Doodle South (10)	Substation	14,632	13,885	12,417	5,067	5,262	4,312	5,067	5,340	4,341
	2				3	3	3	225	3	3
	4				770	817	141	1,072	1,063	141
	6				647	467	339	647	648	453
	8				1,947	1,852	1,449	2,223	2,278	2,126
	10				208	166	111	226	201	112
Fischer West (11)	Substation	20,452	20,014	19,738	4,753	4,536	4,175	6,386	6,129	6,482
	1				309	297	419	450	520	610
	2				1,543	1,430	1,573	1,941	1,776	1,876
	7				611	569	648	850	790	850
	9				690	679	683	802	897	958
	10				199	154	156	211	165	182
	12				1,107			1,225		
Fischer East (11)	Substation	24,096	24,689	21,260	5,262	5,239	5,278	6,645	5,239	6,952
	3				1,282	1,104	1,251	1,454	1,104	1,540
	4				949	677	1,176	1,062	975	1,602
	5				257	159	253	289	159	330
	6				843	713	805	1,233	713	1,125
	8				646	965	1,118	646	1,056	1,868
	11				642			915		
Deerwood (12)	Substation	20,806	22,724	24,338	5,037	5,798	6,102	6,414	6,800	7,826
	1				123	397	678	145	542	768
	2				371	964	1,246	560	1,173	1,574
	3				655	611	867	655	675	1,274
	4				765	1,149	1,012	1,414	1,410	1,273
	5				1,154	1,292	1,215	1,272	1,514	1,874

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
Colonial Hills North (13)	Substation	17472	16,588	16,675	4,481	4,249	4,764	5,387	5,921	5,899
	1				855	754	857	1,031	902	951
	3				177	162	164	192	168	301
	4				771	740	605	928	835	715
	8				1,091	1,027	1,011	1,699	1,500	1,011
	9				94	667	691	150	667	691
Colonial Hills South (13)	Substation	14,264	15,662	12,553	2,760	3,050	3,273	4,185	3,267	4,495
	2				606	665	263	998	970	394
	5				814	815	743	840	991	924
	6				292	330	356	351	430	498
	7				328	303	306	411	422	390
	10				642	635	630	845	917	833
LeMay Lake (14)	Substation	23,545	23,340	20,553	7,681	9,643	10,782	7,681	9,731	11,794
	1				110	3,458	1,890	110	4,360	2,593
	2				543	552	550	631	561	668
	3				785	786	780	1,014	948	849
	4				614	567	1,602	614	1,046	2,151
	5				941	1,001	1,007	1,396	1,386	1,361
	6				734	744	78	849	773	82
Lake Marion (15)	Substation	5,503	5,045	8,900	1,210	1,332	1,148	1,210	1,424	1,214
	1				391	400	140	391	400	218
	3				301	168	287	348	168	349
	4				281	483	543	419	596	592
Lebanon Hills (16)	Substation	19,990	20354	19,635	3,731	3,254	4,011	4,144	3,374	4,247
	1				269	324	523	318	342	661
	2				675	833	1,001	918	906	1,010
	3				907	839	784	910	1,009	994
	4				453	27	182	453	30	316
	5				348	36	311	348	38	311
	6				503	513	500	503	644	529
Dakota Heights (17)	Substation	16,582	21,862	14,516	3,729	3,608	4,267	4,467	4,815	4,780
	1				698	698	685	859	790	719
	2				582	583	730	666	726	893
	3				404	412	321	404	412	321
	4				293	728	525	423	995	853
	5				549	393	244	658	732	244
	6				434	424	447	600	605	609
Marshan (18)	Substation	5772	7,112	6,762	168	134	413	168	134	413
	1				-639	-578	-477	-639	-578	-477
	2				286	278	276	299	300	332
	3				2	48	31	2	48	31
	4				225	215	166	238	215	219
Pilot Knob (19)	Substation	10,637	11,154	11,762	2,301	1,741	2,311	2,661	2,418	3,323
	1				248	255	264	344	363	402
	2				244	244	240	251	298	249
	3				172	176	200	215	223	210
	4				704	222	886	866	222	1,114
	5				645	644	647	873	891	895

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
Wescott Park East (20)	Substation	6,927	6,890	6,953	0	0	0	0	0	0
	1				0	0	0	0	0	0
	3				0	0	0	0	0	0
	5				0	0	0	0	0	0
Wescott Park West (20)	Substation	7,802	7,575	10,145	1,193	1,240	1,619	1,193	2,130	2,023
	2				0	0	0	0	0	0
	4				343	341	496	343	366	600
	6				364	321	364	379	321	477
	7				0	0	0	0	0	0
	8				0	0	981	0	0	1,335
Apple Valley (21)	Substation	20,938	21,971	22,423	4,681	5,475	5,468	6,237	6,562	6,012
	1				704	739	616	704	757	930
	2				1,117	561	1,150	1,265	701	1,334
	3				129	362	361	386	404	436
	4				528	602	642	674	840	801
	5				153	244	176	153	326	435
	6				933	919	937	1,214	1,181	1,068
Dodd Park South** (22)	Substation	18,155	18,772	30,139	3,058	3,434	5,673	3,060	4,364	6,680
	1				762	712	865	837	811	1,072
	2				457	639	629	634	798	906
	3				562	565	658	562	565	819
	4				2	98	985	2	98	1,164
	5				580	538	156	768	538	252
Dodd Park North** (22)	Substation	15,981	16,122		3,849	2,859		4,242	2,900	
	6				502	562	865	643	667	1,072
	7				1,283	544		1,290	544	
	8				1,064	938		1,170	1,119	
	9				728	231		745	352	
Empire (23)	Substation	3,050	3,938	3,920	554	530	452	573	610	646
	1				200	178	371	226	229	498
	2				116	86	138	116	86	152
	3				0	0	0	0	0	0
	4				86	76	105	129	76	125
Vermillion River (24)	Substation	11,684	11,977	15,345	424	739	318	424	739	318
	1				711	693	700	766	767	923
	2				252	257	137	252	257	260
	3				-2,586	-2,593	-2,628	-2,586	-2,593	-2,628
	4				155	284	238	155	297	274
	5				132	146	159	147	172	165
	6				841	841	869	881	948	1,122
Lakeville (25)	Substation	27,806	29,206	28,113	6,576	6,199	5,862	8,050	6,398	8,368
	1				1,372	1,055	1,325	1,502	1,055	1,542
	2				768	802	767	768	1,034	1,066
	3				1,016	741	839	1,393	741	1,396
	4				890	851	854	999	1,087	1,143
	5				728	704	696	849	718	1,005
	6				1,086	1,146	945	1,943	1,705	1,514

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2024	2022	2020	2024	2022	2020	2024	2022	2020
Kenrick (26)	Substation	10498	8650	9,832	3,035	2,967	1,582	3,679	3,357	2,129
	1				130	121	121	164	155	164
	2				1,248	1,180	759	1,305	1,238	922
	3				350	72	384	505	260	475
	4				1,096	840	961	1,271	1,159	1,103
Ritter Park (27)	Substation	17,161	16653	17,155	4,168	4,200	3,735	5,260	5,188	4,781
	2				1,221	1,193	1,084	1,372	1,427	1,375
	3				574	739	568	836	779	788
	4				1,661	1,536	1,454	1,827	1,665	2,249
	5				373	405	369	373	439	419
Barnes Grove (28)	Substation	5610	5364		561	728		620	838	
	1				104	119		104	119	
	2				154	175		185	194	
	3				309	301		309	324	
Nininger (29)	Substation	3,474	4131	3,910	738	629	634	941	629	926
	1				179	157	195	215	294	299
	3				318	283	251	367	324	356
	4				161	141	142	237	197	179
Ravenna (30)	Substation	6,887	7098	6,810	-2,545	649	619	-2,545	1,028	1,027
	1				-3,802	0	0	-3,802	0	0
	3				109	171	163	109	171	163
	4				125	136	163	125	136	185
Burnscott (31)	Substation	10,912	10714	10,730	1,872	2,136	1,653	2,395	2,462	2,246
	1				598	554	428	780	744	428
	2				162	129	148	162	186	150
	3				471	510	421	587	610	432
	4				346	296	303	433	296	397
Randolph (32)	Substation	4,339	5227	4,254	-1,030	-1,061	-1,117	-1,030	-1,061	-1,108
	1				197	188	113	233	196	153
	2				89	101	102	94	131	108
	3				2	2	2	2	2	2
	4				137	107	61	137	107	141
Cedar (33)	Substation	3,082			654			768		
	1				190			190		
	2				226			226		
	3				44			48		
	4				8			8		
	5				0			0		
Eidswold (34)**	Substation	0			0			0		
	1				0			0		
	2				0			0		
	3				0			0		
	4				0			0		
	5				0			0		

505,392 521,178 506,695

Notes

*Backfeed of Castle Rock with VR is classified as abnormal operation and not included in the minimum load determination

**New Substation was energized in 2025, load data was not considered for this study period.

Appendix B – DER Feeder Summary Report

Feeder	Load Control Receiver Loads (kW assumes)										Generating DER Systems (kW is AC Rating)											
	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Standard		Curtailment		Solar		Wind		Storage	
	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
02F801	12	33.3	11	31.2	10	113.4	13	831	3	3	30	24	107.3	0	0	0	0	15	19.72	0	0	0
02F802	13	36.6	21	24.5	20	244.5	7	348.6	3	43.5	30	145	0	0	0	0	1	20	0	0	0	
02F803	32	97.2	4	15.2	9	117	1	47	1	1	14	63	0	0	2	516	0	0	0	0	0	
02F804	9	23.5	10	30.2	6	48	10	442.8	1	2	15	64.5	3	928	0	0	2	36.72	0	0	1	3.84
03F801	647	1670.3	21	46.2	23	161.9	1	65	3	11	88	400.5	0	0	0	0	15	102.664	0	0	1	7.68
03F802	45	121.4	22	69.1	33	402.9	28	2141.6	4	47.7	38	163	0	0	0	0	8	145.83	0	0	0	0
03F803	45	128.3	35	119.8	24	412.4	35	2371.6	3	5.1	48	217	0	0	0	0	5	91.768	0	0	0	0
03F804	51	145.2	20	63.7	27	200.6	22	1414.5	3	18.8	22	99	0	0	0	0	3	26	1	20	0	0
04F801	36	106	15	25.8	14	126.4	4	130.4	0	0	30	125.3	0	0	1	115	3	54.626	0	0	0	0
04F802	22	65.7	17	49.6	13	187.9	4	187	4	25.4	26	119	0	0	0	0	8	132.628	0	0	0	0
04F804	115	351.6	59	189.6	88	722.5	6	252.2	18	128.7	146	642	1	98	0	0	15	282.28	1	20	1	10
05F801	615	1968.5	49	169.7	29	138.6	0	0	9	39.4	48	216	1	216	0	0	24	164.686	0	0	1	10
05F803	810	2484.2	42	136.9	31	158	0	0	9	23.2	51	220.5	2	1085	0	0	36	269.675	0	0	0	0
05F805	455	1363.54	14	42.3	29	151.2	0	0	5	13	16	72	0	0	0	0	11	91.6	0	0	1	5
05F807	48	148.2	1	7.2	6	38	0	0	2	10	3	13.5	3	372	0	0	1	3.77	0	0	0	0
05F809	598	1871.2	24	73.5	33	161.5	0	0	9	27.5	32	144.5	1	167	0	0	10	79.766	0	0	0	0
05F811	779	2245.45	37	113.7	28	144.1	0	0	10	28	17	72	0	0	0	0	18	138.547	0	0	0	0
05F802	617	1751	13	39.3	20	107.8	0	0	4	18.5	29	130.5	3	1728	0	0	21	156.438	0	0	0	0
05F804	826	2164.5	14	47.7	21	84	0	0	1	1	3	13.5	1	559	0	0	2	17.02	0	0	1	10
05F806	186	558.8	5	16.5	11	67.7	0	0	2	7	5	22.5	6	1614	1	737	4	29.06	0	0	0	0
05F808	459	1281.4	8	25.4	13	48	0	0	1	5	60	270	1	407	0	0	7	53.982	0	0	0	0
05F810	809	2399.6	35	156.5	26	155.2	0	0	7	20.2	38	173	5	1312	0	0	5	151.2	0	0	0	0
06F801	200	646.4	28	88.5	12	75.5	0	0	1	3	10	45	1	806	0	0	12	74.824	0	0	0	0
06F802	172	513.9	7	20.7	6	42	0	0	1	6.4	8	37	0	0	0	0	10	78.752	0	0	0	0
06F803	134	423	6	18.5	9	19.2	0	0	1	4	23	103.5	0	0	0	0	12	89.571	0	0	0	0
06F804	286	915.3	18	55.2	5	16.5	0	0	1	5	7	31.5	0	0	0	0	12	116.37	0	0	0	0
06F805	229	731.9	27	86.1	8	33	0	0	1	2	11	49.5	0	0	0	0	18	130.953	0	0	0	0
06F806	74	214.3	7	17	12	87.6	0	0	0	0	4	18	1	461	0	0	2	13.49	0	0	0	0
07F801	43	121.3	8	25.9	19	298.9	14	959	3	13	26	107.3	0	0	0	0	3	61.1	0	0	0	0
07F802	76	212.8	20	60.6	27	253.1	5	442.3	7	53.5	41	186.5	0	0	0	0	3	32.432	1	12.5	0	0
07F803	29	75.7	16	39.2	32	326.4	1	111	1	5	42	184.5	0	0	0	0	5	88.4	0	0	0	0
07F804	35	103.4	36	119.1	50	989.7	16	1128	9	52	57	262	0	0	0	0	11	176.65	0	0	0	0
07F805	81	220.9	36	68	46	644.3	12	843	5	51.9	80	356.4	0	0	0	0	4	94.82	0	0	0	0
08F801	370	1131.4	39	141.9	56	586	0	0	17	114.3	87	395.6	0	0	0	0	17	183.178	0	0	1	9.7
08F802	527	1519.6	20	64.7	19	172.9	0	0	4	16.7	76	340.5	1	98	2	0	4	31.64	0	0	0	0
08F803	481	1425.6	19	68.1	24	134.3	0	0	3	10.5	30	134	1	49	0	0	13	116.95	0	0	0	0
08F804	376	1183.8	23	83.2	46	376.6	0	0	7	22.8	77	341.1	0	0	0	0	7	48.076	0	0	0	0
08F805	57	164.8	4	13.1	5	62.4	0	0	1	0.8	4	18	1	645	0	0	5	35.33	0	0	0	0
08F806	277	919.2	27	101.5	55	517.9	0	0	7	96.4	103	463.5	0	0	0	0	7	99.54	0	0	0	0
09F801	488	1089.45	8	22.1	5	21.9	0	0	1	3	26	117	0	0	0	0	6	50.14	0	0	0	0
09F805	538	1543.1	13	37	12	49.2	0	0	3	9.3	42	269.4	0	0	0	0	7	54.908	0	0	0	0
09F806	304	845.9	5	15.1	5	20.5	0	0	0	0	2	9	0	0	0	0	0	0	0	0	0	0
09F807	186	513	7	21.4	3	11.5	0	0	0	0	4	18	0	0	0	0	2	20.23	0	0	0	0
09F802	655	1796.06	26	68.4	21	90.4	0	0	2	5.4	116	517	0	0	0	0	13	89.69	0	0	0	0
09F803	341	1010.8	17	53.1	18	118.7	0	0	4	14.1	30	135	0	0	0	0	17	105.704	0	0	1	0
09F804	342	1088.8	22	83.5	13	168.9	0	0	3	8.5	24	96	0	0	0	0	12	91.61	0	0	0	0
09F808	33	93.8	0	0	0	0	0	0	0	0	1	4.5	0	0	0	0	1	20.094	0	0	0	0
09F810	323	814.2	8	24.9	5	21.9	0	0	1	4	167	751	0	0	0	0	4	21.08	0	0	0	0
10F801	5	22	1	45.5	0	0	0	0	0	0	0	0	1	1116	0	0	0	0	0	0	0	0
10F803	379	1137.9	23	67.9	23	110.9	0	0	1	2.8	34	153	1	230	0	0	19	140.13	0	0	0	0
10F805	58	183.2	0	0	0	0	0	0	0	0	1	4.5	1	1202	0	0	1	30	0	0	0	0
10F807	118	349.1	5	13.9	4	23	0	0	0	0	6	26.4	0	0	0	0	5	46.074	0	0	0	0
10F802	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10F804	5	25	0	0	0	0	0	0	0	0	1	4.5	2	735	0	0	1	45.36	0	0	0	0
10F806	177	599.5	32	128.1	43	435.1	0	0	7	61	46	207.1	1	0	2	1037	14	121.985	0	0	0	0
10F808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10F810	2	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12F801	341	1072.3	24	76.7	17	70.6	0	0	4	15	42	189	2	3288	0	0	16	119.791	0	0	0	0
12F802	505	1536.1	32	93.4	46	450	0	0	3	4.9	166	740.5	2	1135	0	0	18	177.53	0	0	0	0
12F803	565	1503.6	7	18.2	12	64.7	0	0	4	11	3	13.5	2	672	0	0	3	24.1	0	0	0	0
12F804	704																					

21F801	369	1166.3	20	68.9	9	23.1	0	0	4	9.2	14	61.6	2	2715	0	0	13	125.685	1	20	0	0
21F802	964	2713.9	43	140.6	29	137.3	0	0	4	9.8	25	112.5	1	799	0	0	38	282.313	0	0	0	0
21F803	788	2222	47	146.1	30	140.4	0	0	8	25	23	99	0	0	0	0	19	127.112	0	0	0	0
21F804	550	1635.7	31	107.7	17	120	0	0	2	3.6	70	315	3	2165	1	80	18	134.875	0	0	1	10
21F805	177	564.1	14	48.7	9	54.3	0	0	2	2.5	10	40.5	4	1646	0	0	6	48.355	0	0	0	0
21F806	764	2104.6	38	117	26	139.4	0	0	4	31	49	216	0	0	0	0	10	73.8	0	0	1	10
22F801	543	1435.9	18	47.3	38	233.8	0	0	2	6.1	10	45	5	2526	0	0	6	97.38	0	0	0	0
22F802	455	1268.4	20	55.4	14	68.8	0	0	0	0	27	121.5	1	94	0	0	7	40.973	0	0	0	0
22F803	398	1146.4	14	39.4	11	63.4	0	0	6	20.65	73	328.5	0	0	0	0	30	250.931	0	0	0	0
22F804	22	53	0	0	0	0	0	0	0	0	1	4.5	0	0	0	0	5	21.93	0	0	2	10
22F805	313	905.5	22	77.4	7	41.5	0	0	1	1	51	229.5	0	0	0	0	11	69.775	0	0	0	0
22F806	215	615.7	12	40.6	13	119.1	0	0	5	13.7	40	180	2	718	1	547	14	91.69	0	0	0	0
22F807	539	1566.7	6	24.5	21	198.3	0	0	3	20.5	155	696.8	1	99	0	0	68	475.412	0	0	2	20
22F808	514	1479.6	12	37.6	22	159.6	0	0	2	6.5	86	387	1	642	0	0	46	349.964	0	0	0	0
22F809	436	1323.1	48	158.3	28	139.8	0	0	6	9.7	176	792	1	250	0	0	20	189.966	0	0	0	0
23F801	59	161.1	16	51.7	30	251.9	20	1115.8	3	8.3	40	175.5	0	0	0	0	4	56.238	0	0	0	0
23F802	48	138.4	35	99	38	417.1	27	1750.4	9	83.1	67	295.5	0	0	0	0	6	90.92	0	0	0	0
23F804	26	67.5	22	18.9	27	391.6	5	298	4	8	35	148.8	1	97	0	0	4	83.6	0	0	0	0
24F801	577	1639.9	19	56.6	31	253.8	0	0	0	0	62	277.5	1	92	1	264	24	187.568	0	0	1	0
24F802	66	179.6	15	22.1	35	354.8	9	526.5	3	38	43	196.3	1	350	0	0	10	175.91	0	0	0	0
24F803	64	177.6	26	104.3	24	386.9	3	120.3	1	7.5	49	220.5	0	0	0	0	3	3014.95	0	0	0	0
24F804	16	47.7	2	10.4	3	51	9	394	0	0	9	40.5	1	180	0	0	0	0	0	0	0	0
24F805	6	15	1	3	4	34	0	0	1	0	5	22.5	0	0	1	893	0	0	0	0	0	0
24F806	813	2181.9	14	45	14	92.7	0	0	4	10.8	68	303.5	0	0	0	0	31	208.916	0	0	0	0
25F801	921	2289.2	25	69.4	27	160	0	0	2	15.6	17	76.5	0	0	1	383	49	300.027	0	0	0	0
25F802	248	751.9	13	38.4	14	85.7	0	0	3	13.7	51	225	0	0	1	0	14	96.76	0	0	0	0
25F803	162	451.7	0	0	3	13	0	0	1	0	2	9	1	0	0	0	29	208.488	0	0	1	5
25F804	1721	4542.8	51	150.6	41	201.6	0	0	8	26.55	279	1251	0	0	0	0	73	470.428	0	0	0	0
25F805	1111	2500.1	5	15.2	8	51.8	0	0	1	4.5	305	1365.6	0	0	0	0	10	69.612	0	0	0	0
25F806	565	1511.2	3	9.1	14	102.8	0	0	0	0	17	76.5	2	778	1	1542	26	176.46	0	0	1	10
25F807	326	851.3	4	17.6	44	344.6	0	0	1	5	25	112.5	0	0	0	0	9	62.08	0	0	0	0
25F808	255	720.7	21	62.8	9	54.7	0	0	2	9.5	64	288	0	0	0	0	8	59.521	0	0	0	0
26F801	107	269	5	13.6	4	49	0	0	3	4.1	3	13.5	0	0	0	0	0	0	0	0	0	0
26F802	126	369.92	2	4.1	1	7.5	0	0	1	4	10	45	0	0	1	384	19	127.472	0	0	0	0
26F803	16	133.6	4	17.6	10	75.4	0	0	2	5	6	27	0	0	0	0	0	0	0	0	0	0
26F804	286	867.8	48	176.2	87	837.4	1	5	27	245.4	119	517.5	3	852	0	0	3	35.242	0	0	1	0
27F802	22	100	4	13.5	3	32.6	0	0	1	12	4	18	3	1380	0	0	4	94.6	0	0	0	0
27F803	184	619.7	15	49.4	28	225.3	0	0	8	19.5	41	183.4	1	965	0	0	8	73.376	0	0	0	0
27F804	589	1930.81	32	96.1	35	333.3	0	0	9	40.6	187	927.6	1	706	0	0	37	350.871	0	0	1	6.96
27F805	123	378.5	10	21.1	11	91.2	0	0	7	22.2	41	181	1	770	0	0	3	32.86	0	0	0	0
29F801	142	339.7	7	16.8	19	148.5	1	89	1	5	55	244	0	0	0	0	3	48.37	0	0	0	0
29F803	159	433.9	8	25.8	23	212	2	51.5	7	26.1	23	103.5	0	0	0	0	8	66.889	0	0	0	0
29F804	47	113.5	10	34.7	19	204.4	17	1405.3	1	40	32	137.5	0	0	0	0	0	0	0	0	0	0
30F801	0	0	0	0	0	0	0	0	0	0	0	0	1	4900	0	0	3	4500	0	0	0	0
30F803	33	92.3	13	23.9	16	142	0	0	2	7	25	112.5	0	0	0	0	3	47.4	0	0	0	0
30F804	50	138.5	9	6.2	15	163.3	3	74	2	14	15	67.5	0	0	0	0	1	7.6	0	0	0	0
31F801	346	852.5	10	30.3	14	69.9	0	0	2	4.7	9	39	0	0	0	0	2	40.64	0	0	0	0
31F802	0	0	0	0	0	0	0	0	0	0	0	0	2	2230	1	1048	0	0	0	0	0	0
31F803	274	665.1	8	23.4	2	4.4	0	0	0	0	5	22.5	1	569	1	878	3	25.405	0	0	0	0
31F804	10	49.6	0	0	0	0	0	0	0	0	0	0	1	311	0	0	0	0	0	0	0	0
32F801	30	86	19	31.6	35	463.4	12	611	4	17.7	43	191.3	0	0	0	0	0	0	0	0	0	0
32F802	22	76.7	13	41	23	295.7	5	255	1	20	37	166.5	0	0	0	0	2	12.76	1	10	0	0
32F803	1	2.5	0	0	2	43	1	47	0	0	2	10	0	0	1	276	0	0	0	0	0	0
32F804	90	246.5	50	123.6	63	658.5	49	2484.4	7	55.5	107	471.5	0	0	1	188	14	155.697	0	0	1	5
32F805	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2000	0	0	0	0	0
33F801	175	542.75	2	6.4	18	119	0	0	0	0	139	619.3	0	0	0	0	21	179.4	0	0	0	0
33F802	143	441.1	1	3.6	6	31.6	0	0	1	6	104	459	0	0	0	0	18	104.164	0	0	0	0
33F803	9	29.7	4	13.5	9	94.2	2	85	0	0	11	46.2	0	0	0	0	1	15.4	0	0	0	0
33F804	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34F801	8	20.9	1	0	4	36.3	0	0	0	0	2	9	0	0	0	0	0	0	0	0	0	0
34F802	1	2.3	0	0	0	0	0	0	0	0	0	0	0	0	0	1	8.41	0	0	0	0	0
34F803	13	36.7	5	11.4	7	73.2	0	0	4	44.1	17	72	0	0	0	0	1	7.54	0	0	0	0
34F804	82	252.5	31	48.3	51	639.4	0	0	3	38.7	65	274.7	1	86	0	0	7	89.01	3	21.5	0	0
34F805	11	30.2	5	9.5	5	52.3	0	0	2	12.3	10	45	0	0	0	0	1	11.4	0	0	0	0
Totals:	44531	128470.1	2809	8812.2	3291	28217.28	394	24658.9	596	3534.65	7217	32361.4	119	74981	24	8890	1695	25153.93	10	154	31	203.76

Appendix C – Table Showing where Commission’s Objectives are Discussed in IDP

Planning Objectives: Dakota Electric must discuss in future filings how the IDP meets the Commission’s IDP Planning Objectives, including:

1. *Analysis of how the information in the IDP relates 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 Dakota Electric’s ability to meet the Planning Objectives.*

Planning Objective #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;

Objective #1 Components:	Pages where information is available
Safety	12-16, 68
Security	61-63, 69
Reliability	9-10, 12-15, 20, 32-38, 66, 69, 73, 87-88
Resilience	12-16, 19-20, 69-70, 87-88
Cost	18-19, 51-60, 82, 85-94

Planning Objective #2: Enable greater customer engagement, empowerment, and options for energy services;

Objective #2 Components:	Pages where information is available
Customer Engagement	21-24, 62-64, 95-96
Customer Empowerment	22-23, 44-50, 62-64, 82-84, 95-96
Options for Energy Services	44-50, 82-84, 95-96

Planning Objective #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,

Objective #3 Components:	Pages where information is available
Create Efficient, cost-effective grid	18-19, 44-50, 82, 95-94
Accessible grid platforms to support new products and services	46, 62-65, 95-96
Opportunities for adoption of new distributed technologies	34-38, 46, 51-64

Planning Objective #4: Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and,

Objective #4 Components:	Pages where information is available
Optimized utilization of grid assets	44-50, 62-63, 96
Minimize total system costs	18-19, 51-60, 82, 85-94

Planning Objective #5: Provide the Commission with the information necessary to understand Dakota Electric Association’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.

Objective #5 Components:	Pages where information is available
Provide short-term and long-term plans	69-72, 85-93
Provide costs and benefits of investments	18-19, 51-60, 85-94
Analysis of rate payer cost and value	18-19, 38-39, 51-60, 82, 85-94

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#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
84	David	Freestate	dfreestate@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-139
85	Katelyn	Frye	kfrye@mnpower.com	Minnesota Power		30 W Superiot St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-139
86	Jessica	Fyhrie	jfyhrie@otpc.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-139
87	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-139
88	Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy		408 St. Peter Street Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-139
89	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-139
90	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-139
91	Sean	Gosiewski	sean@afors.org	Alliance for Sustainability		2801 21st Ave S Ste 100 Minneapolis MN, 55407 United States	Electronic Service		No	M-25-139
92	Scott	Greenbert	scott@nautilussolar.com	Nautilus Solar Energy, LLC		396 Springfield Aver, Ste 2 Summit NJ, 07901 United States	Electronic Service		No	M-25-139
93	Sarah	Groebner	sgroebner@redwoodelectric.com	Redwood Electric Cooperative		60 Pine St Clements MN, 56224 United States	Electronic Service		No	M-25-139
94	Tim	Gross	tgross@fuelingmn.com	Fueling Minnesota		3244 Rice Street St. Paul MN, 55126 United States	Electronic Service		No	M-25-139
95	Cody	Gustafson	cgustafson@mnpower.com			null null, null United States	Electronic Service		No	M-25-139
96	Tom	Guttormson	tom.guttormson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd Ramsey MN, 55303 United States	Electronic Service		No	M-25-139
97	Natalie	Haberman	townsend@fresh-energy.org	Fresh Energy		408 St Peter St # 350 St. Paul MN, 55102 United States	Electronic Service		No	M-25-139
98	Nicholas	Haeg	haeg@fresh-energy.org			12298 Bass Trail Sauk Centre MN, 56378 United States	Electronic Service		No	M-25-139
99	James	Haler	jhaler@southcentralelectric.com	South Central Electric		71176 Tiell Dr P. O. Box 150	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
				Association		St. James MN, 56081 United States				
100	Joe	Halso	joe.halso@sierraclub.org	Sierra Club		1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-139
101	Donald	Hanson	dfhanson@ieee.org			P. O. Box 44579 Eden Prairie MN, 55344 United States	Electronic Service		No	M-25-139
102	John	Harlander	john.c.harlander@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
103	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	M-25-139
104	Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.		701 E. Cary Street Richmond VA, 23219 United States	Electronic Service		No	M-25-139
105	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
106	Tiana	Heger	thegeer@mnpower.com	Minnesota Power		30 W. Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
107	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	M-25-139
108	Annete	Henkel	mui@mnuutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	M-25-139
109	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
110	Mari	Hernandez	mari@irecusa.org	IREC		null null, null United States	Electronic Service		No	M-25-139
111	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	M-25-139
112	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	M-25-139
113	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
114	Casey	Horan	choran@edf.org	Environmental Defense Fund		123 Mission St San Francisco CA, 94105 United States	Electronic Service		No	M-25-139
115	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	M-25-139
116	Samantha	Houston	shouston@ucsusa.org	Union of Concerned Scientists		1825 K St. NW Ste 800 Washington DC, 20006 United States	Electronic Service		No	M-25-139
117	Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
118	Jan	Hubbard	jan.hubbard@comcast.net			7730 Mississippi Lane Brooklyn Park MN, 55444 United States	Electronic Service		No	M-25-139
119	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-139
120	Reuben	Hunter	bhunter@madisonei.com	Madison Energy Investments		8100 Boone Blvd Suite 430 Vienna VA, 22182 United States	Electronic Service		No	M-25-139
121	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	M-25-139
122	John S.	Jaffray	jjaffray@jjrpower.com	JJR Power		350 Highway 7 Suite 236 Excelsior MN, 55331 United States	Electronic Service		No	M-25-139
123	Robert	Jagusch	rjagusch@mmua.org	MMUA		3025 Harbor Lane N Minneapolis MN, 55447 United States	Electronic Service		No	M-25-139
124	Chris	Jarosch	chris@carrcreekelectricservice.com	Carr Creek Electric Service, LLC		209 Sommers Street North Hudson WI, 54016 United States	Electronic Service		No	M-25-139
125	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	M-25-139
126	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
127	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
128	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD,	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						57042 United States				
129	Philip	Jones	phil@evtransportationalliance.org			1402 Third Ave Ste 1315 Seattle WA, 98101 United States	Electronic Service		No	M-25-139
130	Julie	Jorgensen	julie@greenmark.us.com	Greenmark Solar		4630 Quebec Ave N New Hope MN, 55428-4973 United States	Electronic Service		No	M-25-139
131	Kevin	Joyce	kjoyce@tesla.com			null null, null United States	Electronic Service		No	M-25-139
132	Mahmoud	Kabalan	mahmoud.kabalan@stthomas.edu	University of St Thomas		2115 Summit Ave. Mail OSS100 School of Engineering Saint Paul MN, 55105 United States	Electronic Service		No	M-25-139
133	Camille	Kadoch	ckadoch@raponline.org	Regulatory Assistance Project		50 State Street Suite 3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-139
134	Cliff	Kaehler	cliff.kaehler@novelenergy.biz	Novel Energy Solutions LLC		4710 Blaylock Way Inver Grove Heights MN, 55076 United States	Electronic Service		No	M-25-139
135	Ralph	Kaehler	ralph.kaehler@gmail.com			13700 Co. Rd. 9 Eyota MN, 55934 United States	Electronic Service		No	M-25-139
136	Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC		260 Salem Church Road Sunfish Lake MN, 55118 United States	Electronic Service		No	M-25-139
137	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	M-25-139
138	Jack	Kegel	jkegel@mmua.org	MMUA		3025 Harbor Lane N Suite 400 Plymouth MN, 55447-5142 United States	Electronic Service		No	M-25-139
139	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	M-25-139
140	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
141	Tom	Key	tkey@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-139
142	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
143	Jack	Kluempke	jack.kluempke@state.mn.us		Department of Commerce	85 7th Place East Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
144	Aaron	Knoll	aknoll@greeneespel.com	Greene Espel PLLP		222 South Ninth Street Suite 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
145	Steve	Kosbab	skosbab@meeker.coop	Meeker Cooperative Light and Power		1725 US Hwy 12 E Litchfield MN, 55355 United States	Electronic Service		No	M-25-139
146	Nathan	Kostiuk	nathan.c.kostiuk@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-07 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
147	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	M-25-139
148	Michael	Krause	michaelkrause61@yahoo.com			1200 Plymouth Avenue Minneapolis MN, 55411 United States	Electronic Service		No	M-25-139
149	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
150	Corrina	Kumpe	ckumpe@mysunshare.com			null null, null United States	Electronic Service		No	M-25-139
151	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	M-25-139
152	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
153	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-139
154	Burnell	Lauer	blauer.sundial@gmail.com	Sundial Solar		3209 W. 76th St #305 Edina MN, 55435 United States	Electronic Service		No	M-25-139
155	Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures		315 Manitoba Ave Ste 200 Wayzata MN, 55391 United States	Electronic Service		No	M-25-139
156	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
157	Benjamin	Levine	blevine@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
158	Becky	Li	bli@rmi.org			17 State St 25th floor unit 2500 New York NY, 10004 United States	Electronic Service		No	M-25-139
159	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-139
160	Carl	Linville	clinville@raponline.org			50 State Street Suite #3 Montpelier VT, 05602 United States	Electronic Service		No	M-25-139
161	Phillip	Lipetsky	greenenergyproductsllc@gmail.com	Green Energy Products		PO Box 108 Springfield MN, 56087 United States	Electronic Service		No	M-25-139
162	Jody	Londo	jody.l.londo@xcelenergy.com	Xcel Energy		414 Nicillet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	M-25-139
163	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
164	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	M-25-139
165	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
166	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-139
167	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-139
168	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-139
169	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	M-25-139
170	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
171	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-139
172	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
173	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	M-25-139
174	Jason	Maur	jason.maur@renesolapower.com	Renesola Power Holdings, LLC		850 Canal Street 3rd Floor Stamford CT, 06902 United States	Electronic Service		No	M-25-139
175	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-139
176	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-139
177	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	M-25-139
178	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	M-25-139
179	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-139
180	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	M-25-139
181	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	M-25-139
182	Tim	Mergen	tmergen@meeker.coop	Meeker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	M-25-139
183	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
184	Brian	Millberg	fwengineering@comcast.net			695 Grand Ave #222 Saint Paul MN, 55105 United States	Electronic Service		No	M-25-139
185	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
186	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-139
187	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-139
188	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-139
189	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-139
190	David	Moeller	dmoeller@allte.com	Minnesota Power			Electronic Service		No	M-25-139
191	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	M-25-139
192	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
193	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
194	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-139
195	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-139
196	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	M-25-139
197	Anthony	Nelson	amnelson@otpc.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	M-25-139
198	Ben	Nelson	benn@cmpasgroup.org	CMPMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	M-25-139
199	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55401 United States				
200	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	M-25-139
201	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
202	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy		426 17th Street, Suite 700 Oakland CA, 94612 United States	Electronic Service		No	M-25-139
203	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-139
204	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	M-25-139
205	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	M-25-139
206	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	M-25-139
207	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	M-25-139
208	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	M-25-139
209	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	M-25-139
210	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticello MN, 55362 United States	Electronic Service		No	M-25-139
211	Matthew	Olsen	molsen@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139
212	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
213	Wendi	Olson	wolson@otpc.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139
214	Carol A.	Overland	overland@legalelectric.org	Legalelectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	M-25-139
215	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
216	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
217	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	M-25-139
218	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-139
219	Dean	Pawlowski	dpawlowski@otpc.com	Otter Tail Power Company		PO Box 496 215 S. Cascade St. Fergus Falls MN, 56537-0496 United States	Electronic Service		No	M-25-139
220	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
221	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	M-25-139
222	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-139
223	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	M-25-139
224	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
225	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	M-25-139
226	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	M-25-139
227	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
228	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	M-25-139
229	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	M-25-139
230	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	M-25-139
231	David G.	Prazak	dprazak@otpc.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-139
232	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-139
233	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	M-25-139
234	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	M-25-139
235	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	M-25-139
236	Generic Notice	Regulatory	regulatory_filing_coordinators@otpc.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139
237	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	M-25-139
238	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-139
239	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	M-25-139
240	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
241	Michael	Riewer	mriewer@otpc.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-139
242	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-139
243	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	M-25-139
244	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	M-25-139
245	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-139
246	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
247	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	M-25-139
248	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-139
249	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street Minneapolis MN, 55407 United States	Electronic Service		No	M-25-139
250	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	M-25-139
251	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	M-25-139
252	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	M-25-139
253	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
254	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	M-25-139
255	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
256	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-139
257	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55024 United States				
258	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	M-25-139
259	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-139
260	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
261	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	M-25-139
262	Rob	Scott Hovland	rob.scott-hovland@mnenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-139
263	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	M-25-139
264	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	M-25-139
265	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	M-25-139
266	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	M-25-139
267	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	M-25-139
268	Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy		414 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
269	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-139
270	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	M-25-139
271	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Litchfield MN, 55355 United States				
272	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	M-25-139
273	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	M-25-139
274	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	M-25-139
275	Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy		305 Saint Peter St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-139
276	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	M-25-139
277	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
278	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	M-25-139
279	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	M-25-139
280	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-139
281	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	M-25-139
282	Karl	Sonneman	karl17@hbci.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	M-25-139
283	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
284	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-139
285	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Saint Paul MN, 55102 United States				
286	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
287	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
288	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	M-25-139
289	Cary	Stephenson	cstephenson@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139
290	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
291	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-139
292	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	M-25-139
293	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	M-25-139
294	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	M-25-139
295	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	M-25-139
296	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	M-25-139
297	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-139
298	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	M-25-139
299	Stuart	Tommerdahl	stommerdahl@otpc.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
300	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-139
301	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
302	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	M-25-139
303	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	M-25-139
304	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-139
305	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr NW St 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-139
306	Adam	Tromblay	atromblay@noblesce.com	Nobles Cooperative Electric		22636 US Hwy. 59 P.O. Box 788 Worthington MN, 56187-0788 United States	Electronic Service		No	M-25-139
307	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-139
308	Alan	Urban	alan.m.urban@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-139
309	Matt	Van Arkel	mvanarkel@newleafenergy.com			55 Technology Drive Suite 102 Lowell MA, 01851 United States	Electronic Service		No	M-25-139
310	Gary	Van Winkle	gvanwinkle@mylegalaid.org	Mid-Minnesota Legal Aid		111 N Fifth St Ste 100 Minneapolis MN, 55403 United States	Electronic Service		No	M-25-139
311	John	Vaughn	nik@rreal.org	Rural Renewable Energy Alliance		3963 8th Street SW Backus MN, 55435 United States	Electronic Service		No	M-25-139
312	Ellen	Veazey	lveazey@solarunitedneighbors.org	Solar United Neighbors		1350 Connecticut Ave NW Ste 412 Washington DC, 20036 United States	Electronic Service		No	M-25-139
313	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	M-25-139
314	Curt	Volkman	curt@newenergy-advisors.com	Fresh Energy		408 St Peter St	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Saint Paul MN, 55102 United States				
315	Wendy	Vorasane	wendy.vorasane@idealenergies.com			null null, null United States	Electronic Service		No	M-25-139
316	Robert J.V.	Vose	rvose@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-139
317	Stacy	Wahlund	swahlund@otpc.com	Otter Tail Power Company		215 S. Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-139
318	Sarah	Walinga	swalinga@solarcity.com	Energy Freedom Coalition		3055 Clearview Way San Mateo MN, 94402 United States	Electronic Service		No	M-25-139
319	Kevin	Walker	kwalker@beaconinterfaith.org	Beacon Interfaith Housing Collaborative		null null, null United States	Electronic Service		No	M-25-139
320	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	M-25-139
321	Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		No	M-25-139
322	Samantha	Weaver	samantha@communitysolaraccess.org	Coalition for Community Solar Access		1380 Monroe St. Washington DC DC, 20010 United States	Electronic Service		No	M-25-139
323	Elizabeth	Wefel	eawefel@flaherty-hood.com	Missouri River Energy Services		525 Park St Ste 470 Saint Paul MN, 55103 United States	Electronic Service		No	M-25-139
324	Sarah	Whebbe	swhebbe@mnseia.org	MnSEIA		445 Minnesota Street Suite 730 St. Paul MN, 55101 United States	Electronic Service		No	M-25-139
325	Joshua	Williams	joshua@highlandfleets.com	Highland Electric Fleets		200 Cummings Center Suite 273-D Beverly MA, 01915 United States	Electronic Service		No	M-25-139
326	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	M-25-139
327	John	Williamson	john.williamson@state.mn.us	Minnesota Department of Labor and Industry		443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	M-25-139
328	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way	Electronic Service		No	M-25-139

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Suite 1500 Reston VA, 20190 United States				
329	Danielle	Winner	danielle.winner@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-139
330	Heidi	Winter	hwinter@co.murray.mn.us	Murray County		2500 28th Street PO Box 57 Slayton MN, 56172 United States	Electronic Service		No	M-25-139
331	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	M-25-139
332	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-139
333	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	M-25-139
334	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-8920 United States	Electronic Service		No	M-25-139
335	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188-1022 United States	Electronic Service		No	M-25-139
336	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	M-25-139
337	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	M-25-139
338	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-139