DAKOTA ELECTRIC ASSOCIATION

Your Touchstone Energy® Cooperative

November 1, 2023

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

Subject: ***Dakota Electric Association 2023 IDP Report***

In the Matter of Distribution System Planning
for Dakota Electric Association
Docket No. E-111/CI-23-420

Dear Mr. Seuffert:

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 9, 2022, the Commission issued an *Order Accepting Integrated Distribution Plan and Modifying Filing Requirements* (September 9 Order) in Docket No. E111/M-21-728. Ordering Point No. 3 stated:

> Require Dakota to file, in its next IDP filing, a thorough discussion of the installation of a utility-operated energy storage system (which would be charged with energy that would otherwise cause back-feeding during the day and that would then discharge that energy in the evening) in light of recent state and federal infrastructure programs. The discussion must include how to calculate cost to benefits impacts and how such storage solutions affect its wholesale power supply contracts and obligations.

Dakota Electric notes that we previously submitted two informational filings regarding the required stakeholder process in Docket No. E111/M-21-728, the 2021 IDP proceeding. Our August 3, 2023 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 12, 2023 where it presented the preliminary findings of its IDP Report. This meeting was attended by other utilities and stakeholders that participated in the 2021 IDP process. We filed our presentation material on September 18, 2023 in Docket No. E111/M-21-728 and in this docket.

<u>Dakota Electric Compliance</u>

Dakota Electric submits its 2023 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 Order in Docket No. E111/M-21-728, and its June 7, 2023 Order in Docket No. E999/CI-20-800.

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 and consultants) to prepare this third biennial Integrated Distribution Plan. The attached plan covers the detailed filing requirements outlined in the Commission's previous orders.

Conclusion

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

Sincerely,

/s/ Craig Turner

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____

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Certificate of Service

I, Melissa Cherney, 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/CI-23-420*

Dated this 1st day of November 2023

/s/ Melissa Cherney

____
Melissa Cherney

Dakota Electric Association Integrated Distribution Plan (IDP) Report November 2023

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, and E-999/CI-20-800

Filed in Docket No. E-111/M-23-420

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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.

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 (consumers) side of Dakota Electric's main service's electric meter.

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

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): A Distributed Energy Resource is any resource on the distribution system that produces electricity. For the purposes of this report, DER includes energy efficiency and Demand Side Management.

Distributed Energy Resource Management System (DERMS): Is a 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 electricity. This term includes energy storage systems but does not include energy efficiency and Demand-side Management.

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.

Kilo-Watt (kW): This is a measurement of either capacity available or demand requirements.

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): Is a 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 also 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): This is a 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. The Commission's IDP Order requires each regulated electric utility in Minnesota to file an IDP every two years. This is the third Integrated Resource Plan (IDP) report submitted by Dakota Electric. This 2023 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, 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 its order 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 transparency 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 a greater amount of 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 a minor 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 in large 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 can 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 the capacity to supply the needs of the 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 transition increases, overall planning of the electrical distribution systems is getting more difficult, 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 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.

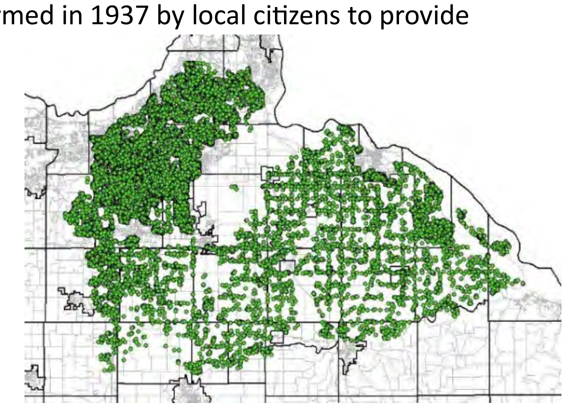


Figure 1. Dakota Electric's Service Territory

As shown in the adjacent figure most of the electric services are concentrated in the northern, 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. Member-owned and member-focused is in the promise of Dakota Electric's service statement. This 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 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 of homes and businesses.

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 electric 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.

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

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

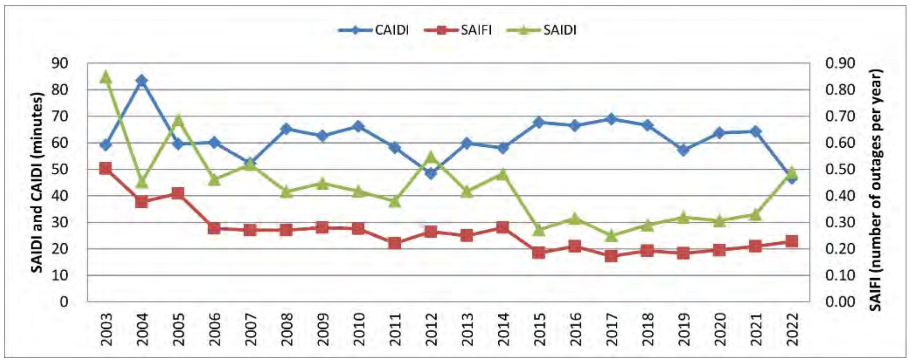
> Every public utility shall furnish safe, adequate, efficient, and reasonable service; provided that service shall be deemed adequate if made so within 90 days after a person requests service. Upon application by a public utility, and for good cause shown, the commission may extend the period for not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

c) Reliability

Coupled with the requirement-to-serve, the reliability of the electric supply is equally as important to the members of Dakota Electric. 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.

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 actually 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.

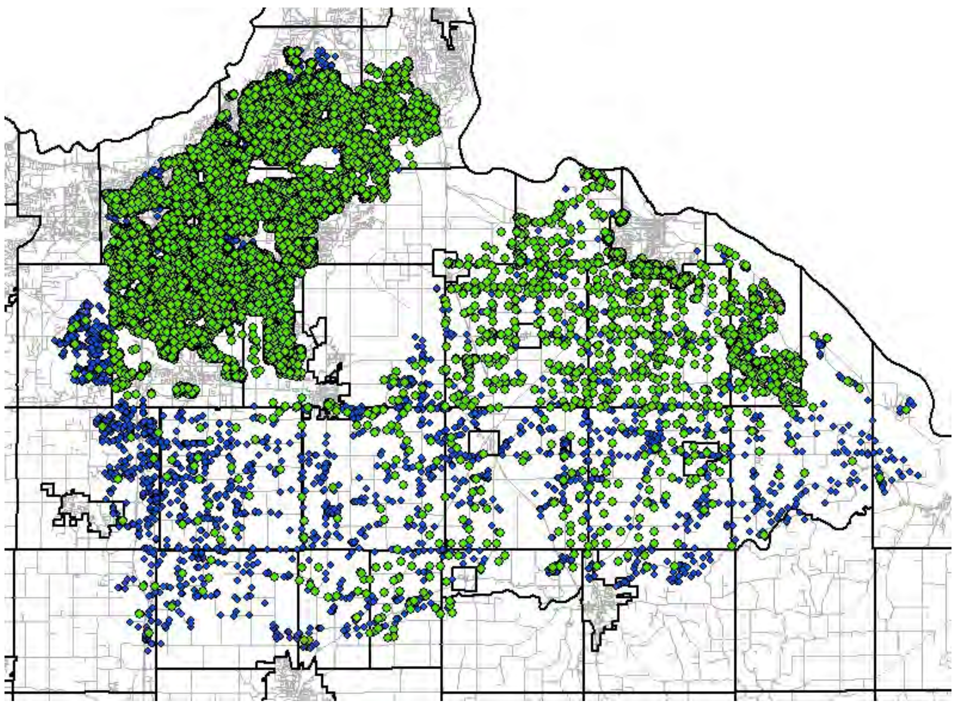
d) Demand Side Management

Dakota Electric has an extensive demand-side management system and can control (shed) as much as 100 megawatts (MW) during the summer months and around 70 MW during winter months. The load control consists of AC units, water heaters, irrigation, and other heating devices such as room heaters and hot tubs. 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. 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 higher. Dakota Electric, in coordination with Great River Energy (GRE), 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 most costly. 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 demand-side management system includes over 45,000 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 are being exchanged with new devices. The new LCRs use the same radio frequency mesh network as the AGi meters use to communicate.

The following figure shows the location of installed load control receivers. The new AGi LCRs are shown in green and the legacy LCRs are shown in blue. The exchange of LCRs is expected to be completed in 2024. Below is a snapshot of the replacement progress as of October 2023.

Figure 2. Map of Load Control Receiver Installations

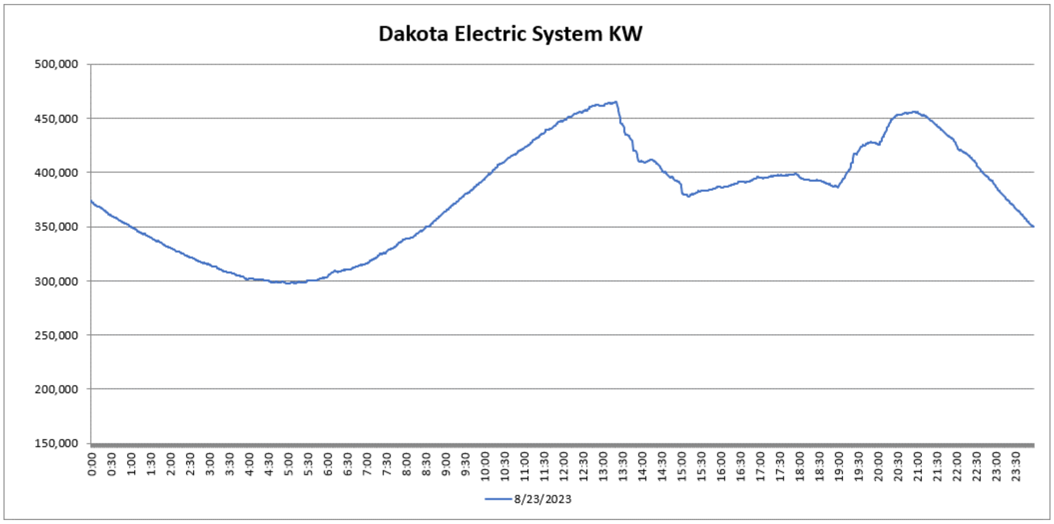


Included in Dakota Electric's demand side program is an interruptible rate for its commercial members that have installed full capacity generation. During peak load events or system emergencies, these members can transfer all their electrical load to their on-site generation when requested by Dakota Electric. 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's distribution feeder along with the member's generation to supply their campus during peak load periods or during weather events.

Through the 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.

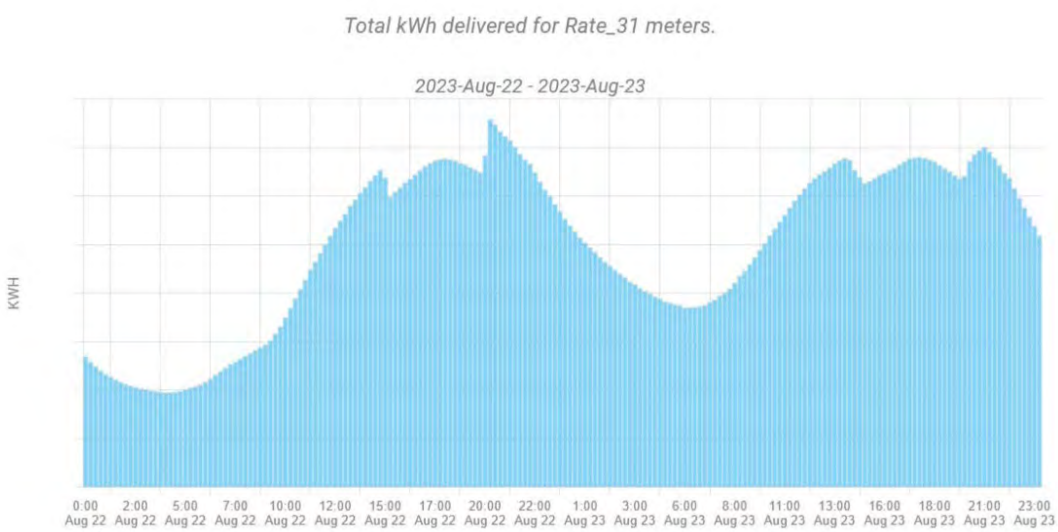
The following graph shows the total Dakota Electric load curve for a peak summer day in 2023. This graph clearly illustrates the amount of load control which was achieved on this day. The amount of load which is available to be controlled varies each control day depending upon many factors, such as the day of the week, the temperature of the proceeding day, etc. This graph illustrates the robustness and importance of Dakota Electric's load management programs. Without load control, the maximum load on the system could have easily exceeded 500 MWs.

Graph 2. Summer Peak Day (Aug 2023) with Load Management



The next graph shows the load curve for services on the residential rate for two consecutive demand response days in August 2023. Notice the difference between the two curves. The first day load control was initiated for all loads, at the same time. This resulted in all loads restoring at the same time. Notice the peak after control is greater than before control. For the second day, all the loads were individually controlled for the same amount of time but were instead staggered for starting control. As individual loads reached the amount of time for their control, the restoration was naturally staggered. The spreading out, over time, of restoration greatly limited the rebound peak during the second day of control. Dakota Electric used these events to test the results for two different control schemes.

Graph 3. Residential Loads over Concurrent Peak Summer Days



e) Highlights of Key Findings

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 economically 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. We continue to work with Great River Energy on this issue, but there have been difficulties 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 improvements to the transmission interconnection process and supply chain environment this will 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.

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. By 2027, Great River Energy's electrical supply is forecasted to utilize mostly renewable energy resources. Great River has done an excellent job of transiting from coal to renewable resources and is now working on long-term storage options to help firm up these variable resources.

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 a 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.

Reduction of Costs for Integrating DER

Dakota Electric has worked to improve the internal processes required to review and approve the interconnection of new distributed energy systems to the distribution system. Over the past few years, the average cost to support each DER interconnection has been greatly reduced by Dakota Electric through several internal process improvements. These changes include: the implementation of the AGi advanced metering project, which eliminated the need to replace the main meter with a more expensive bi-directional meter; modifying several internal processes to reduce the labor required to review applications; and implementing the use of iPADs by the field technicians to facilitate access to information by the field crews and in-house engineering. The use of electronic files speeds up the review process and reduces the cost and labor involved with printing out one-lines and other data used by field crews. The implementation of the NOVA DER application portal (2019) has also helped streamline internal processes and process tracking. In addition to improving the internal process, the NOVA portal also improves the process for the DER installers and their interactions with Dakota Electric. Below is a table showing the reduction in average total costs per installation and average net costs to Dakota Electric, which are not covered by the DER applicant.

Table 1. Costs for Interconnection of DER to the Distribution System

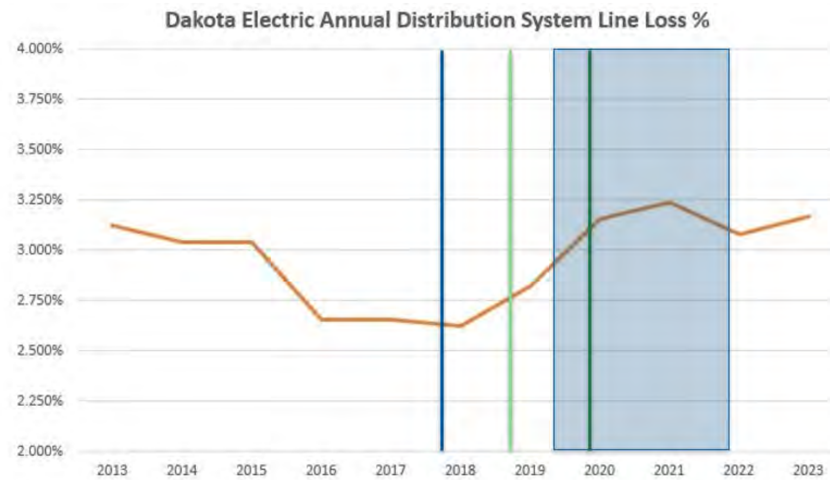
Category	2018	2019	2020	2021	2022
# of Interconnections per year	40	98	138	371	322
Total DEA Costs	$57,437	$111,390	$146,066	$186,009	$175,627
Average DEA cost per DER	$1,436	$1,137	$1,058	$501	$545
Total Receipts	$4,700	$11,818	$23,924	$55,467	$53,180
Average Receipt per DER	$118	$121	$173	$155	$140
NET Total Cost to Dakota Electric	$52,734	$99,572	$122,142	$130,542	$122,447
Net Dakota Electric's Cost Per DER Interconnection	$1,318	$1,016	$885	$352	$380

Over time, as more DER is interconnected with the distribution system, it is expected that the average costs of integrating a new DER with the distribution system will start to increase. The initial DER in an area, or on an existing transformer, seldom causes the need to upgrade the facilities. When subsequent DER are proposed for interconnection, there then becomes a risk of additional costs to increase the local distribution system, especially the local distribution transformer. As more DER is proposed to be integrated with in the same area, larger and larger costs to upgrade the distribution system are likely to occur.

Increasing Distribution System Losses

Prior to 2017, Dakota Electric did not have utility scale (large) solar systems interconnected with the distribution system and there were less than 100 small member owned solar systems interconnected. Since 2017,[4] Dakota Electric has installed three multi-megawatt solar systems and members have installed over 1,000 member owned solar systems on their homes.

Graph 4. Dakota Electric's Distribution System Annual % Losses – Past 10 Years



In the graph above, it is clear that the average distribution system energy losses have increased since 2018. This was a bit of a surprise for the Dakota Electric engineers as they felt that losses could increase with the addition of solar systems, but the amount of increase is considerably greater than expected. It was also surprising because the Dakota Electric system had experienced a trend downward in system losses as various system improvement projects had been undertaken. Furthermore, with the replacement of the older meters with AGi metering, Dakota Electric expected a reduction in distribution system energy losses. The graph above shows the beneficial impact in 2021 and 2022 of this transition. The installation of AGi meters started in the summer of 2020, but it was not until the end of 2021 that most homes and businesses had AGi meters installed. Dakota Electric believes the improvement in losses in 2022 was the result of the new AGi meters.

After reviewing the data more closely, it is believed that the utility scale solar systems, and possibly some of the member owned solar systems, are impacting the distribution system losses due to the extra losses being created by the flow of generated excess energy flowing through more of the distribution system than energy that is directly supplied by the distribution substations. The negative impact of these systems on distribution losses outweighs the improvement with line losses from the AGi Project. This is especially evident with the utility scale solar systems because there is little load adjacent to the solar system to absorb the generated energy. In this instance, much of the energy produced by the facilities flows up the circuit to the substation and then flows back out on the other feeders, to the loads. The energy generated at these facilities increases energy losses because solar generated energy goes through the step-up transformer at the solar farm and then along the distribution wires to the

[4] In 2017, Dakota Electric added a 1 MW solar system; in 2018, a 2 MW solar system; and in 2019, a 3 MW solar system.

substation, before flowing back out to the individual loads and through the local transformer. Transformers are historically a significant cause of system losses, so these operating characteristics can easily double the normal distribution energy losses.[5]

Beyond Dakota Electric's utility scale solar facilities, the increase in line losses may also be related to smaller member-owned solar systems if the output from these facilities is less coincident with the member's energy use. When output is more coincident with member energy use, there is necessarily a reduction in the amount of energy exported onto the distribution system because the member uses it at the premise. However, the nature of solar production in the Dakota Electric service territory is less conducive to more coincident production because peak solar production is typically in the early to midafternoon hours when homeowners are more likely to be out of the home. The excess energy generated during the day passes through the distribution transformer and then, at night, as the home uses much of its energy, the solar is generating little if any energy and the energy for the home again passes though the transformer. In this case, the amount of line losses will increase for homes with DER. This issue of increased line losses can compound if a utility is required to increase the size of the distribution transformer to support the larger flow of excess energy generated by the member's solar.

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

From the Commission's 2019 IDP Order, 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.

From Dakota Electric's perspective, the IDP Orders seek information that focuses on the integration of DER 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;

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[5] It is important to note that this review is only looking at distribution system losses and does not include changes to the transmission losses.

- discussion about possible issues which could occur that would affect higher DER levels of integration; and
- information being learned using Dakota Electric's new AGi metering system.

Dakota Electric crafted its report in a manner that is more topic focused, and it hopes this format is helpful to the Commission and responsive to any requests or questions that it may have. Since this is the third IDP Report, Dakota Electric expects future changes and process improvements going forward and is prepared to provide any clarification or additional information requested by the Commission or other parties. Although not specifically related to this topic, in terms of meeting the Commission's objectives in future IDP Reports, Dakota Electric requests that the Commission issue a clean order with all updated and relevant ordering points. Dakota Electric believes this will streamline our analysis in future IDPs and reduce the risk of us, and other utilities, missing relevant pieces of information that the Commission needs to meet its planning objectives.

g) Member Equity and Equality

Dakota Electric participated in each of the IDP stakeholder meetings for the other regulated electric utilities and observed that other utilities were asked about how the utility's distribution planning process considers social, economic, and equity issues. These are important issues and Dakota Electric is committed to furthering these objectives and addressing them where necessary. Dakota Electric was an active participant in the Commission's investigation into diversity in the industry and is committed to these goals. Dakota Electric has also worked collaboratively with the Prairie Island Indian Community on their Net Zero Initiative, which includes the construction of a 4.5MW solar facility located on the Dakota Electric distribution system.

Dakota Electric is unique among Minnesota regulated utilities in that it is a cooperative. Under the cooperative structure, Dakota Electric is member owned. Unlike an investor-owned utility, our members have a direct say in the operation and direction of the cooperative by electing the Board of Directors. Dakota Electric's business model is also based on a one member, one vote principle, so all our members, regardless of size, economic, or social status, have equal representation. This business model also guides our system operation goals and approach.

Dakota Electric strives for a highly reliable electrical service for all our members, regardless of size or other characteristics. We strive to achieve a homogeneous supply of electricity and service for our membership. For example, as engineers review the distribution system, they use the same reliability standards for all parts of the service territory. Although, as noted above, Dakota Electric's overall system performance and reliability is strong, and consistently amongst the best in the industry, our operations staff does periodically observe members who experience an unacceptable number of outages (classified as more than three separate outages in a year). Dakota Electric has been active in targeting these members with higher levels of outages and attempting to remedy these issues. Dakota Electric believes that all members deserve, and expect, safe and reliable electrical service. It is our expectation that this proactive approach will further decrease the number of outages for members and improve overall service quality and satisfaction.

The issue of electric reliability at an individual member level has also been discussed recently at the Commission. In response to directives in the annual SRSQ, Dakota Electric has started tracking system-wide data on this topic. In recent years, the Commission has 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 2. Dakota Electric CEMI Performance (2020-2022)

YEAR	$CEMI_4$	$CEMI_5$	$CEMI_6$	$CEMI_7$
2020	0.82%	0.34%	0.05%	0.01%
2021	0.14%	0.07%	0.01%	0.00%
2022	0.54%	0.06%	0.00%	0.00%

The information in the above table shows Dakota Electric's CEMI performance since 2020. Overall, Dakota Electric's data is favorable and, in 2022, it shows that less than one percent, or approximately 620 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 overheard 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 the lower incomes. Unfortunately, since these areas also have a greater percentage of overhead equipment, these are areas of our system that tend to have 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 access practicable.

Dakota Electric has identified one census track in Burnsville Minnesota, which has reliability concerns and is also classified as a Justice40 disadvantaged community. The homes in the area are supplied by overhead back lot line wires and served by older substation equipment. In early 2023, Dakota Electric submitted a grant request, as part of a larger group of cooperatives and municipalities, for funding from the Infrastructure Investment and Jobs Act (IIJA) to convert the back lot line overhead to underground supply for much of this census track and to replace 40-year-old substation equipment for the two substations which are suppling this census track and the immediate area around. In October 2023, Dakota Electric learned that this grant request was not selected by the federal government. Dakota Electric is considering the possibility of resubmitting this grant request in future grant submissions.

The other area where Dakota Electric experiences poorer relative reliability is in the rural areas where there are long cross-country overhead wires. These are also older installations with trees impacting the wires and are hard to reach and maintain. Dakota Electric works on improving these rural areas with reliability concerns when they are identified. Many times, reliability concerns in rural areas are driven by vegetation and older trees impacting lines.

Below is a picture of outages on the Dakota Electric system caused by vegetation in 2022. 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. 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 3. Map of Quantity of Outages in 2022 – Caused by Vegetation

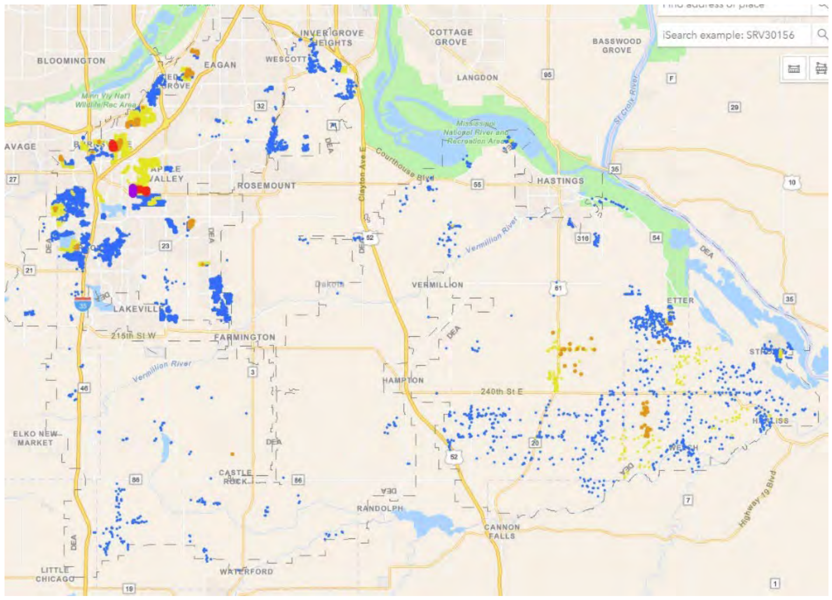
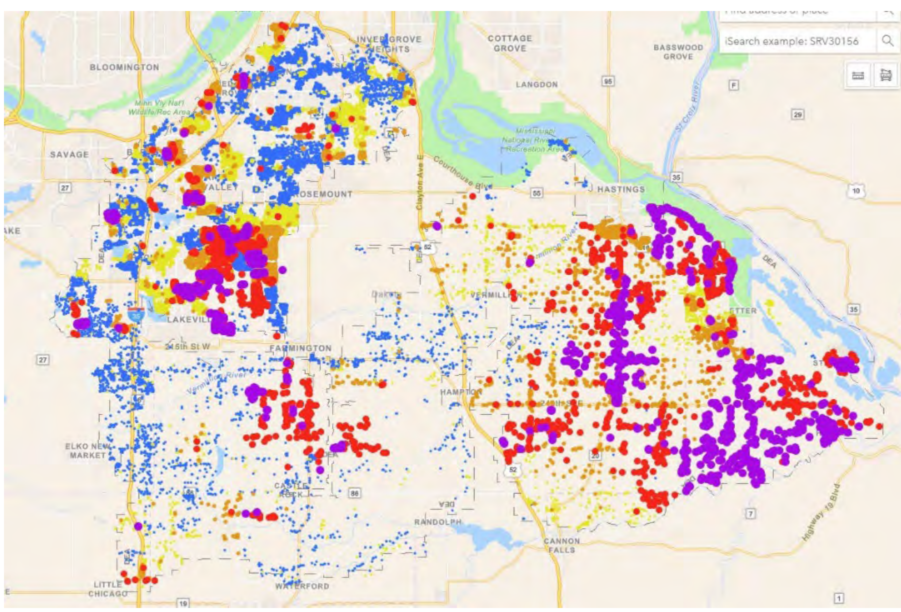


Figure 4. Map of Number of Outages in 2022 – All Causes



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 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.

h) 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 to improve processes and operations. Dakota Electric is governed by a Board, made up of members, which are elected by the membership. The Board provides direct and immediate feedback for the staff from 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 results in Dakota Electric being naturally, and consciously, responsive to the members. In addition to regular member engagement, Dakota Electric also hosted two outside stakeholder meetings. These are summarized in the following section of this report.

There are many other events which Dakota Electric sponsored throughout the 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 us 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.

Figure 5. Dakota Electric Information Booth

Figure 6. CEO Talking with Members

The event also highlights the cooperative's electric vehicles, like the Chevy Bolt, and provides information on electric vehicle programs. CEO Ryan Hentges actively participates, addressing attendees and emphasizing the cooperative's community involvement.

Beyond the entertainment, the Member Appreciation Event underscores the cooperative's commitment to community involvement. Members regularly contribute non-perishable food items for 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 Trends Expo

Dakota Electric's Energy Trends Expo, hosted in collaboration with Lakeville Friends of the Environment, is an annual event for its members and the local community. Held each September at the Eagan Community Center, this expo serves as a platform for exploring the latest developments and innovations in the energy sector. The expo in 2022 marked a significant milestone as it featured an impressive display of electric vehicles, including all-electric trucks and SUVs, generating a lot of interest and questions. Notably, it showcased two Rivian trucks, an F-150 Lightning, and a Rivian SUV, offering attendees a firsthand look at the future of sustainable transportation.

The theme of the 2022 expo was "Reliability and Optimization," addressing concerns about grid reliability amidst media reports of potential "rolling blackouts." Dakota Electric, in collaboration with Great River Energy, presented their ongoing efforts to enhance grid reliability and optimization. The Energy Trends Expo serves as a platform to discuss crucial energy trends shaping our present and future, making it an essential event for individuals seeking to stay well-informed about the evolving energy sector.

Figure 7. Members Visiting with informational booths.

Electric Vehicle Ride and Drive – May 2023

Dakota Electric hosted its third Ride and Drive event in 2023. The event provides an opportunity for Dakota Electric members to experience electric vehicles (EVs) firsthand in a relaxed and pressure-free environment. This environment helps them make informed choices about transitioning to sustainable transportation options. Attendees not only had the chance to test drive various electric vehicles but also engage with EV owners at the static display, 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.

The 2023 Ride and Drive Event showcased an impressive lineup of electric vehicles available for test drives, including the Mercedes EQS, Mercedes EQB, Mercedes EQE, Volkswagen ID.4, Hyundai Ioniq 5, Tesla Model 3, Tesla Model X, Volvo XC40 Recharge, and Polestar 2. The event saw strong participation with 292 registered attendees. With an ever-expanding range of electric vehicles available, the Ride and Drive event serves as a crucial platform for members to explore the exciting world of EVs, while receiving valuable information from the cooperative.

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

- Apple Valley Music in the Park – On June 16, Dakota Electric hosted the Apple Valley Arts Foundation's Music in the Park. Salsa Del Sol played to a large crowd, and LED Lucy danced and entertained kids and adults alike.

- 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 becoming 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.

- Electric Vehicle Grant Program - Great River Energy offered a grant program to its cooperatives to support the purchase of electric vehicles used as a part of a fleet by distribution cooperative members. Great River Energy's program had $60,000 available. Dakota Electric helped its members receive 50% of the available funds. Eagan Police Department - $20,000 for Tesla Model Y to be used as a squad car. City of Apple Valley - $10,000 for Chevrolet Bolt to be used for code compliance and inspections.

  Dakota Electric also works to assist municipalities in completing and submitting grant applications for new electric vehicle charging stations.

Figure 8. Electric Eagan Police Vehicle

- Food Drive – September 2023 - Hosted at Hy-Vee in Lakeville. At the event, Dakota Electric gathered 1200 pounds of food, and $636 dollars in donations. Dakota Electric matched $1 to each pound of food and matched all donations for an additional $1850.

Figure 9. Food Collection Booth at HyVee

- 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 – In March 2023, Dakota Electric board members and staff participated in the 2023 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 - In April 2023, Dakota Electric board members and staff were on hand at the Apple Valley Home and Garden Show on April 1. About 2,500 people attended the show, which featured about 90 local businesses.

- Crops Day at Dakota Electric - For the fifteenth 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 was held on Wednesday, March 22, 2023, at Dakota Electric's headquarters.

- 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 10. Staff Ready for Questions

[6] https://greenstep.pca.state.mn.us/.

i) IDP Stakeholder Outreach

On January 8, 2021, the Commission held a stakeholder discussion regarding Integrated Distribution Planning (IDP). As part of the conclusion to this stakeholder discussion, the Commission drafted a next step which stated in part, "Individual utility stakeholder meetings are encouraged to continue the relevant discussions in preparation of the 2021 IDPs."

Although the Commission's Order in Docket No. E111/M-21-728 did not include a utility stakeholder requirement, The Cooperative believes strongly in a collaborative process and concluded that continued stakeholder engagement for the 2023 IDP was important. Dakota Electric took steps to engage with other parties that are not necessarily members. We refer to these parties as "external stakeholders" in this report and, given the evolving nature of distribution planning, Dakota Electric believes these parties are also important and provide important input into our planning process. The Cooperative held a stakeholder meeting where various city public works departments were briefed on the information being developed for the 2023 IDP. This meeting was held at the Farmington City offices and occurred on June 23, 2023.

Dakota Electric also provided notice to parties registered in the Dakota Electric IDP Docket, relevant state agencies, and other Minnesota regulated utilities regarding a planned stakeholder workshop. Dakota Electric hosted an online stakeholder workshop on September 12, 2023 to present preliminary findings for the IDP. The agenda for the meeting included the following:

- AGi project update;
- DER forecasts for the Dakota Electric system (Solar and Electric Vehicles);
- Discussion on Distribution Planning and how Dakota Electric is planning for electrical vehicle charging;
- Overview of the proposed five-year distribution system investments and capital budget; and
- Key capital projects that Dakota Electric is planning for the next five years;

The presentation covered background information on Dakota Electric's business model, existing load management programs, trends in electric vehicles and distributed solar, current capital spending, and forecasts of potential loads and impacts on the distribution system. The meeting agenda and final presentation materials were filed as part of this docket on September 18th, 2023. Representatives from Commission Staff, Minnesota Power, and Xcel Energy were in attendance.

2) ELECTRIC VEHICLE FORECASTS AND ANALYSIS

a) Planning for Electrical 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 to 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 is focused 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 such as supply issues for raw material for batteries and the overall higher cost of electric vehicles. 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:

- <u>Residential EV Charging</u>. This represents vehicles purchased by our residential members and charged at their residence. The residential vehicles are expected to be mostly recharged 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. This retail charging does, however, 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.

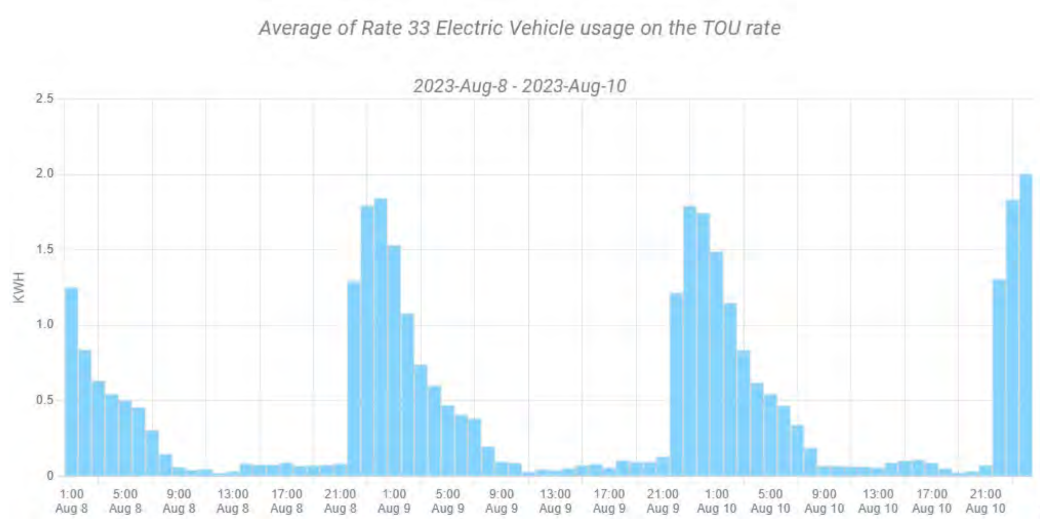
Dakota Electric’s engineers have looked at each of these classes of EV charging and developed a vision for how we expect each to impact the distribution system. The engineers continue to follow EVs and their characteristics and will continue to learn and adapt to these different EV use cases. As part 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 grow. 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. Getting 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.

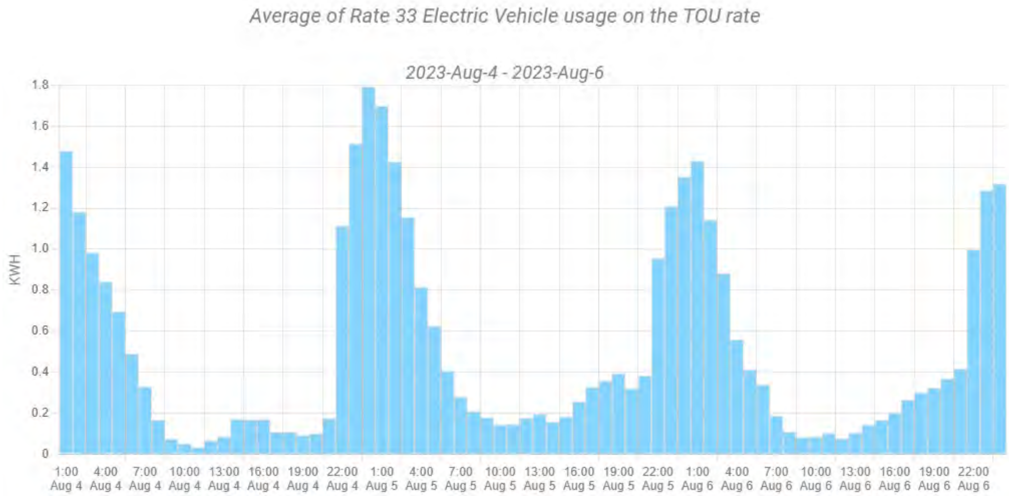
Looking into the future, as electrical demand is shifted to the off-peak periods, Dakota Electric will need to adjust the EV charging rates and/or add new rate options to spread out the recharging over the available off-peak periods. Based upon the typical driving habits of our membership, a residential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

Graph 5. 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 6. 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 at the off-peak rate. 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, we 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. 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 recharging. It is exciting that our 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 the 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 out 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 be replacing 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 member may also need to replace the secondary wires on their property which are the connection with the Dakota Electric system. Dakota Electric is optimistic that recently passed Federal and State tax incentives related to electrical panel upgrades will simplify and improve this part of the EV transition for members living in older properties.

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 is unclear if electrical panel upgrade tax credits apply in this situation but, if they do, this will hopefully offset the costs of these upgrades.

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 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 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.

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?
- Where do I have room 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 through the many issues involving adding EV charging to their facility is a top priority 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 recharging 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 DRMS and 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 will have the greatest impact to the local distribution system because its characteristics and requirements are different than other charging types. Specifically, these operations need to have the ability to recharge their vehicles 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 recharging. When looking at larger delivery vehicle fleets, they may be able to recharge some of their vehicles each evening but also need to recharge 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 recharging 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 loads.

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 a new data center or 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 to other users, there are limits placed on how large of 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.

Supporting Fast Charging in the Dakota Electric Service Territory

Dakota Electric has worked with the state of Minnesota to identify locations that would be a good fit for the National Electric Vehicle Infrastructure (NEVI) plan. In preparation for the state program, Dakota Electric's team identified interchanges that had capacity for up to 1MW capacity to support EV charging. This work done by Dakota Electric was included in the State's transportation plan for NEVI funding.[7] These chargers are much like the fleet chargers discussed above in that we do not have experience with how they will be used. Although most sources believe that residential EV charging will primarily occur at home, the use of fast chargers will necessarily develop over time to support instances where home charging is not possible.

In contrast to home charging, which will mostly occur during nighttime (off-peak periods), DCFCs will be mostly used during the daytime (on-peak periods). Since consumers and fleet operators who use fast charging are there to quickly charge their vehicle, there will be limited ability to curtail this electrical demand, without significant consumer dissatisfaction. Dakota Electric is aware that utilities in other parts of the country control or throttle fast chargers during periods of expected high costs, or potential reliability concerns, but the corresponding issue is customer dissatisfaction because chargers may be unavailable or operating at unacceptably slow rates. There are solutions that attempt to address this overall concern by tying fast chargers with battery storage. However, these charging platforms are higher cost and further exacerbate the low load factor concern for these applications.

[7] https://talk.dot.state.mn.us/ev-infrastructure-plan

The unique characteristics of this form of EV charging will have a significant impact upon the capacity requirements and infrastructure needs of the distribution system. Fast charging stations will not be evenly spread across the distribution system, like residential charging, they will instead be spot loads at light vehicle charging stations and concentrated in industrial and commercial areas for fleet charging. To support fast charging, new feeders, and in some cases new or upgraded substations, will be required to supply these large electrical loads.

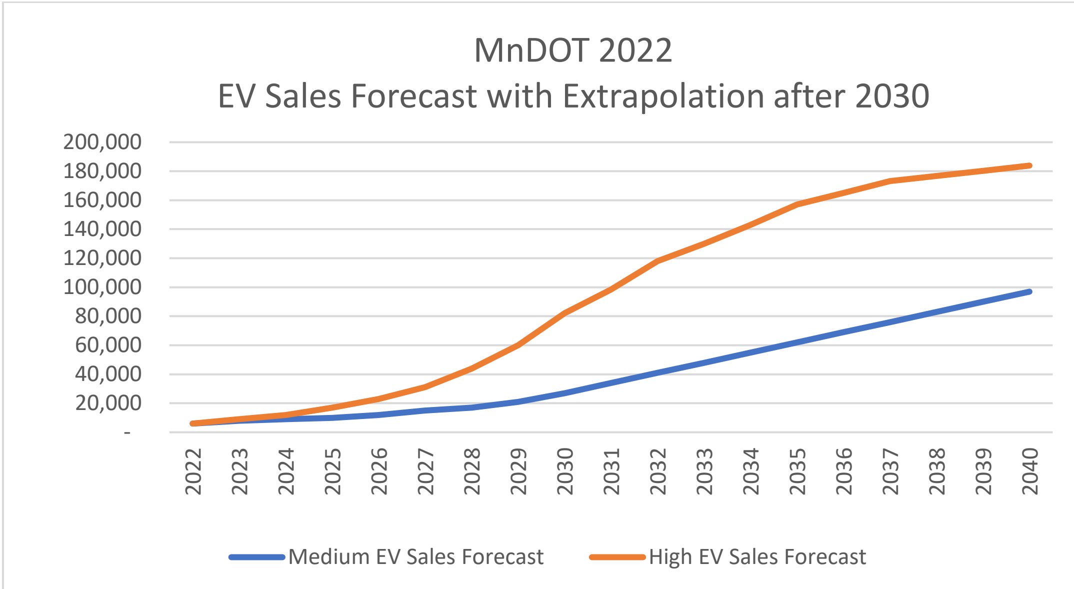
b) Forecast of Electric Vehicle Charging on the Dakota Electric System

For a variety of reasons, EV sales in Minnesota and the upper Midwest have lagged the rest of the country. Arguably the primary reason for these lower sales figures is the relatively rural nature of Minnesota compared to higher population densities found in coastal areas. Minnesota's lower population density requires longer driving distances and greater range anxiety. The lack of adequate fast charging facilities further amplified these range anxiety concerns. During 2021 and 2022, limited availability of EVs for sale at dealerships appears to have affected adoption of EVs by consumers. Starting in 2023, the availability of EVs is starting to change with some dealerships either having EVs immediately available or arriving soon. This increased vehicle availability is likely driven by improvements in manufacturer supply chains and Minnesota's adoption of the clean cars standard. Even with the recent uptick in Minnesota EV sales, Minnesota continues to lag the national average. On a positive note, the number of EVs being interconnected in the Dakota Electric service territory continues to accelerate.

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. However, applying these forecasts to Dakota Electric's suburban service territory, likely under forecasts EV growth for Dakota Electric. 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 5 years (2018-2022), Dakota Electric has seen the number of EVs on our off-peak programs go from 269 to 1,207 vehicles. That is over 400% growth in just a few years. When examining data from the first part of 2023, EV growth within the Dakota Electric service territory continues to accelerate.

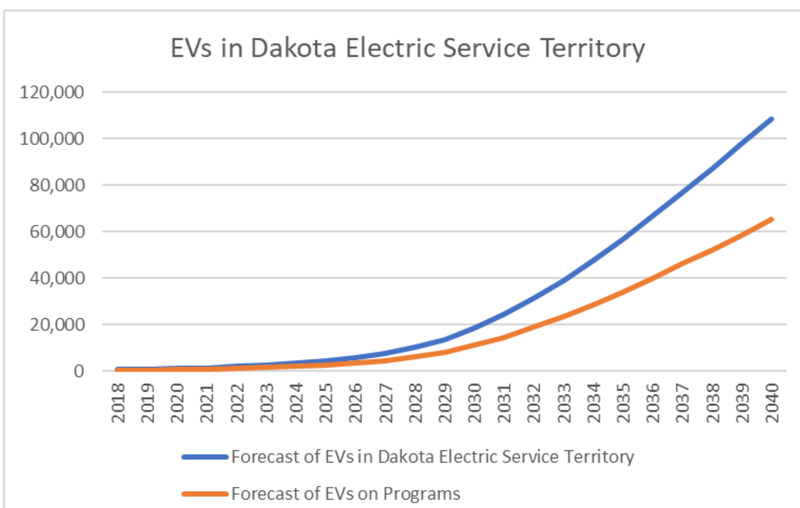
The following EV forecast for the Dakota Electric service territory was created using the growth rates in the MnDOT 2022 EV forecast (High). The MnDOT forecast provided EV sales numbers up to 2030. This forecast was then extrapolated through 2040. Below is a graph showing the Medium and High EV sales 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.

Graph 7. MnDOT Statewide 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. 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 associations off-peak rates. For planning purposes, the amount of "off-peak" EVs is forecasted to remain around 60% of the total number of vehicles. Dakota Electric is optimistic that it can continue to convince our members to utilize our EV programs and, through existing, new, and future programs, reduce the impact of the EVs on the distribution system and wholesale power costs.

Graph 8. Forecast of # of Electric Vehicles Charging on the Dakota Electric System



To date, Dakota Electric has been extremely successful in getting EV owners to participate in our special EV programs. A high percentage, estimated at 50%-60%, of members with EVs have signed up to utilize one of the lower cost EV charging rates. 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 our special EV rates. In December 2021, the PUC reported that there were 1,409 EVs in the Dakota Electric service territory and there were 692 services (49%) signed up for EV programs at Dakota Electric. In December 2022, the PUC reported that there were 2,046 EV in the service territory and 1,207 services (59%) were on one of the EV programs. The actual percentages of vehicles on EV programs is likely higher, as Dakota Electric only counts the home as a single number on a program even if that home has multiple vehicles recorded in the PUC EV count.

Starting in 2023, Dakota Electric is seeing a constant increase in new members signing up for our EV programs. In just the first half of 2023, the total membership utilizing EV programs went from around 1,000 to just over 1,200. In 2023, Dakota Electric revised the EV forecast using MnDOT 2022 forecast and 2023 EV enrollment levels in our off-peak and TOU programs. This updated forecast projects over 20,000 EVs in the service territory by 2030, which is double the number Dakota Electric was estimating in the prior forecast that was completed in early 2022.

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 recharged can have a large 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 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 advanced AGi meters, Dakota Electric engineers continue to learn how our membership is charging their EVs. In 2022, with over 650 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.[8] This approach limits the amount of time where the vehicle is totally recharged. 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.

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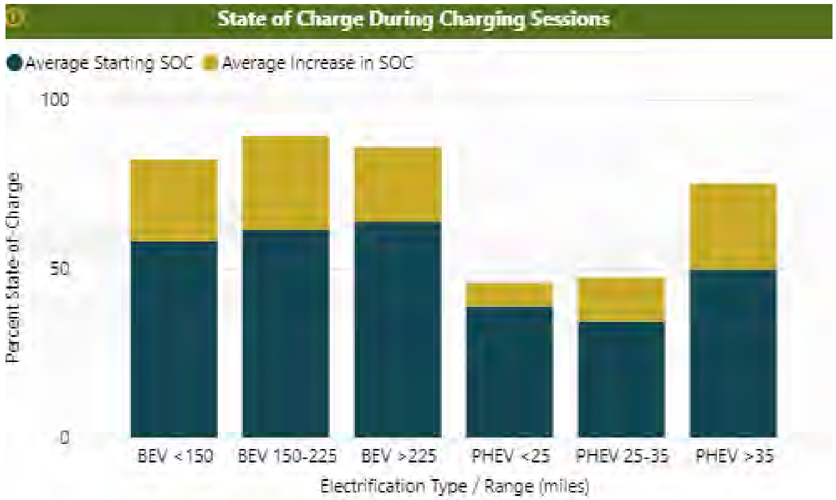
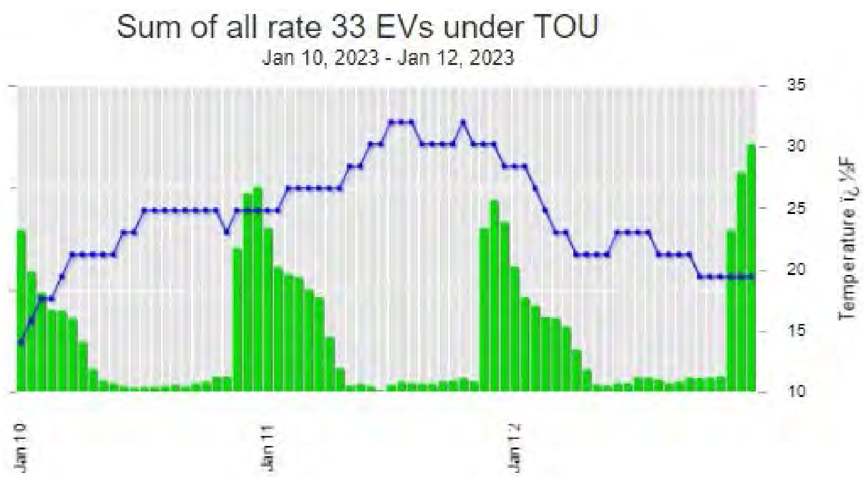
[8] www.energetics.com/evwatts-vehicle-dashboard

Figure 11. 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.

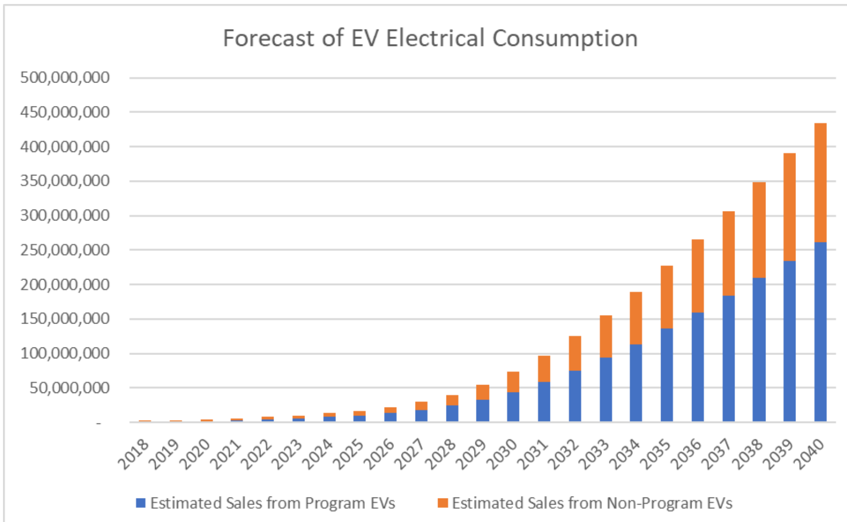
Graph 9. Daily Recharging Pattern for EVs on TOU Rate



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, we see that an 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 kwhr. The average is closer to 400 kwhr 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 kWhr per month; as such, the 300-400 kWhr increase in electrical consumption due 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 kWhr 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 10. Forecast of Electrical Consumption by EVs

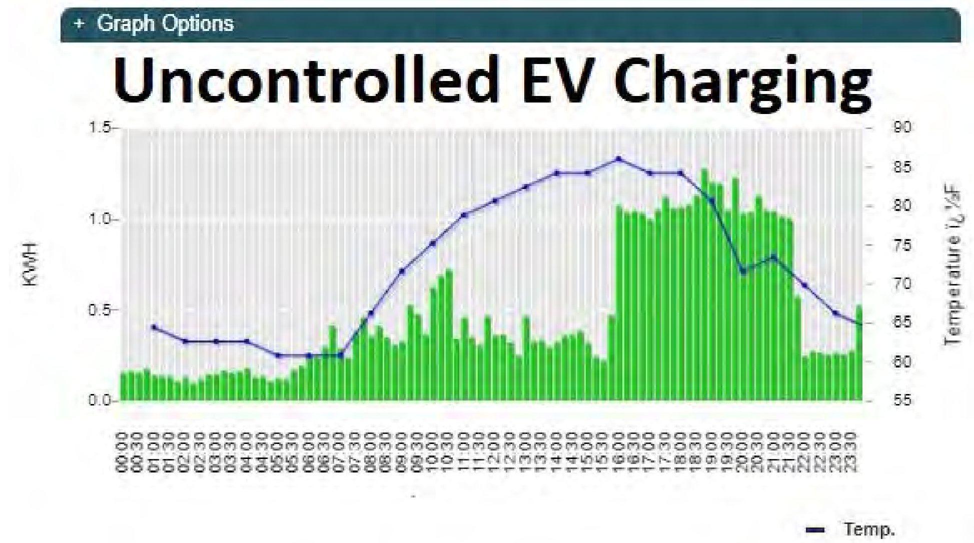


Dakota Electric is fortunate that standard design practices used over the past decades for the distribution system allow for growth in the electrical demand from our members. It is important to note that average residential consumption was significantly higher on a monthly kwhr basis but has decreased over the past 10-20 years due to efficiency improvements in appliances, such as air conditioners and refrigerators, and due to the use of LED lighting. 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 <u>some</u> available capacity for adding additional energy consumption such as EV charging.

While 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 11. 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.

3) FORECASTS OF MEMBER OWNED DER INTERCONNECTIONS

a) Forecast of Member owned Solar Interconnections.

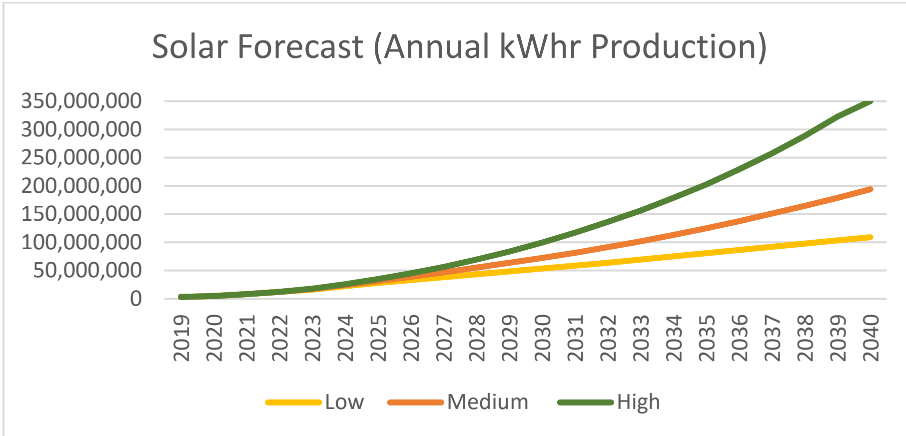
Over the past two decades, Dakota Electric has gone from a handful of member owned solar systems interconnected with the distribution system to now over 1,000 member-owned solar systems. Most of these member-owned systems have been installed in the past 5 years. DER installations on the Dakota Electric system have been strong the past 5 years and this strong growth has leveled off in 2023. There may be various reasons for this slowdown, but Dakota Electric has observed supply chain issues in small solar installations and increases in the overall costs of installations. The average cost of systems installed before COVID was around $33,000. In 2021, the average cost had increased to over $35,000 and, in 2022, the average cost jumped to over $41,000. These higher costs for systems have decreased the economic benefits for our membership. In 2023, the average cost per kW for these systems is around $5,500. There is a large range in costs per kW depending upon the installation, with some installations running as high as $8,000 - $9,000 per kW.

Dakota Electric worked with Great River Energy on forecasting future member owned solar interconnections for the Dakota Electric system. As with the 2021 IDP solar forecast, we 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.

The Low forecast assumes continued tightening in the market due to supply chain issues and the costs of the systems remaining at the recent higher levels. The Medium forecast is based upon a return to lower, pre-Covid installation prices and improved supply chain availability. While all three forecasts consider the impacts of the federal tax credits, the Medium and High forecasts have placed a higher weight on the impacts of these federal incentives. The High forecast assumes a continued robust level of installations into the near future and that the current leveling of the number of installations in the service territory is temporary. The Medium forecast incorporates the effects of the recent leveling of the number of new installations.

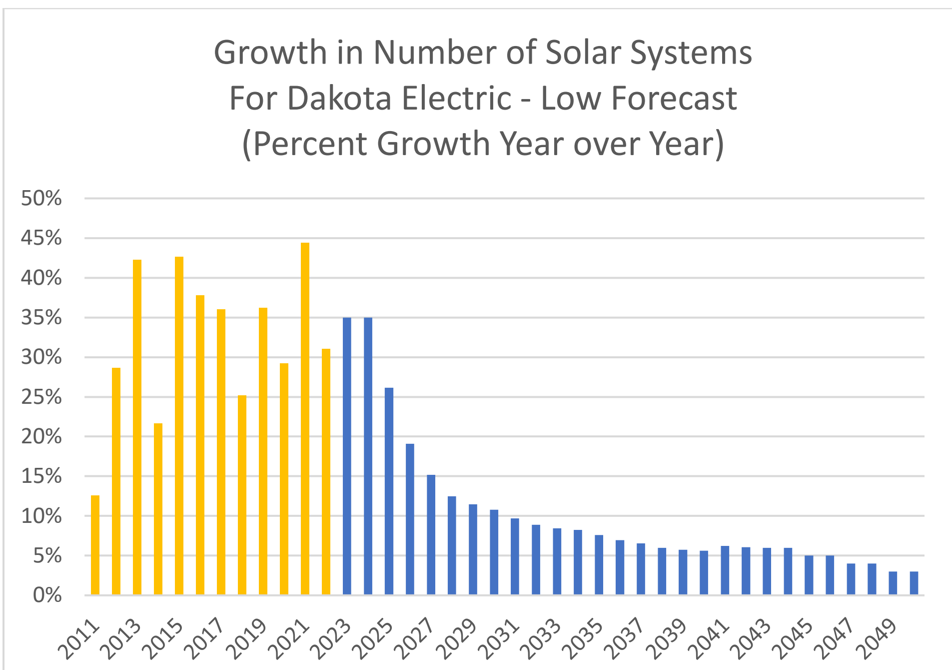
The graph below represents the total energy generated by the member owned solar, much of which will be consumed by the member within their home or business. Although the majority of energy is consumed by the member, there is still a significant amount of energy, on average 30-40%, that is generated by the solar member owned solar systems and is immediately fed back into the distribution system and consumed by other homes and businesses. The net energy received by the distribution system, from net metered homes and business, is compensated by Dakota Electric at full retail rates.

Graph 12. Forecast of Total Energy Production – Member Owned Solar (Medium Forecast)

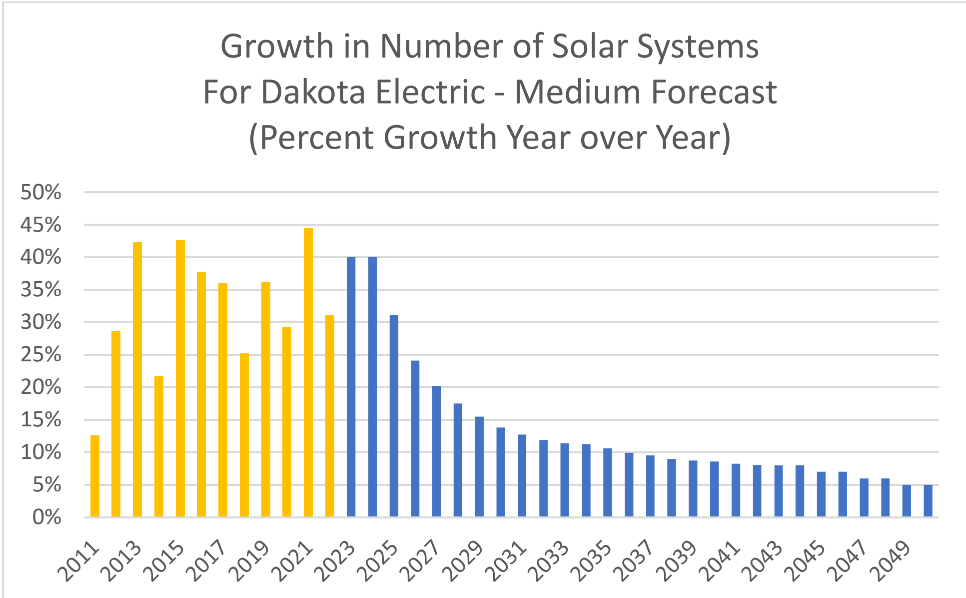


The following graphs show the different annual percent growth rates for the three levels (Low, Medium, High) of member owned solar forecasts.

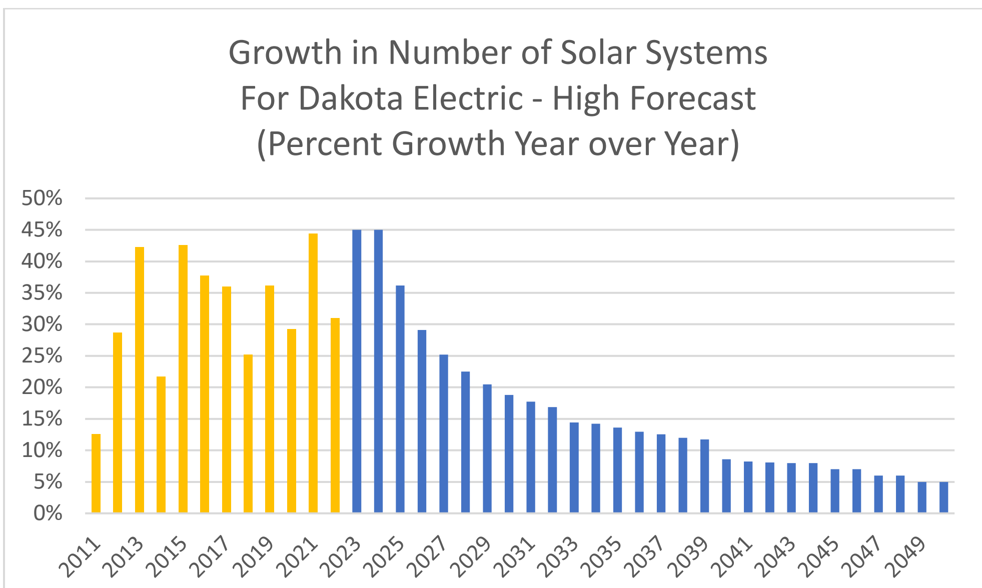
Graph 13. Forecast (Low) Annual % Growth of Member Owned Solar Systems



Graph 14. Forecast (Medium) Annual % Growth of Member Owner Solar Systems



Graph 15. 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 3. Member Solar – Low Forecast

		Low Forecast	**15% capacity factor**	
Year	Number of Solar Units	Total kW capacity	Total Solar Energy (kwhr)	% Growth
2006	2	11	14,717	
2007	6	20	26,280	
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	1446	12568	16,513,899	35%
2024	1952	16966	22,293,763	35%
2025	2462	21404	28,124,814	26%
2026	2933	25494	33,499,621	19%
2027	3379	29369	38,591,089	15%
2028	3801	33038	43,411,720	12%
2029	4237	36833	48,398,812	11%
2030	4695	40810	53,624,213	11%
2031	5151	44773	58,831,913	10%
2032	5608	48748	64,054,911	9%
2033	6081	52855	69,451,124	8%
2034	6582	57212	75,176,477	8%
2035	7082	61557	80,885,885	8%
2036	7573	65827	86,496,118	7%
2037	8068	70129	92,149,304	7%
2038	8552	74338	97,680,261	6%
2039	9042	78596	103,274,627	6%
2040	9549	83001	109,063,356	6%
2041	10144	88174	115,860,608	6%
2042	10760	93530	122,897,921	6%
2043	11406	99141	130,271,796	6%
2044	12090	105090	138,088,104	6%
2045	12695	110344	144,992,509	5%
2046	13329	115862	152,242,135	5%
2047	13863	120496	158,331,820	4%
2048	14417	125316	164,665,093	4%
2049	14850	129075	169,605,046	3%
2050	15295	132948	174,693,197	3%

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 percent growth over the prior year for the number of new installations.

Table 4. Member Solar – Medium Forecast

		Medium Forecast	**15% capacity factor**	
Year	Number of Solar Units	Total kW capacity	Total Solar Energy (kwhr)	% Growth
2006	2	11	14,717	
2007	6	20	26,280	
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	1499	13033	17,125,524	40%
2024	2099	18246	23,975,734	40%
2025	2753	23931	31,445,500	31%
2026	3417	29701	39,027,184	24%
2027	4107	35700	46,910,122	20%
2028	4826	41945	55,115,436	17%
2029	5573	48441	63,651,656	15%
2030	6342	55124	72,433,388	14%
2031	7148	62131	81,640,737	13%
2032	7997	69511	91,337,886	12%
2033	8911	77453	101,772,650	11%
2034	9912	86161	113,215,678	11%
2035	10963	95290	125,210,510	11%
2036	12052	104758	137,651,407	10%
2037	13201	114747	150,777,527	10%
2038	14389	125077	164,350,774	9%
2039	15645	135992	178,694,031	9%
2040	16992	147695	194,070,975	9%
2041	18390	159854	210,047,653	8%
2042	19875	172760	227,006,790	8%
2043	21465	186581	245,167,333	8%
2044	23182	201507	264,780,720	8%
2045	24805	215613	283,315,370	7%
2046	26542	230706	303,147,446	7%
2047	28134	244548	321,336,293	6%
2048	29822	259221	340,616,471	6%
2049	31313	272182	357,647,294	5%
2050	32879	285791	375,529,659	5%

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 percent growth over the prior year for the number of new installations.

Table 5. Member Solar – High Forecast

		High Forecast	**15% capacity factor**	
Year	Number of Solar Units	Total kW capacity	Total Solar Energy (kwhr)	% Growth
2006	2	11	14,717	
2007	6	20	26,280	
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	1553	13499	17,737,150	45%
2024	2252	19573	25,718,868	45%
2025	3066	26650	35,017,660	36%
2026	3958	34408	45,211,494	29%
2027	4956	43078	56,604,149	25%
2028	6071	52767	69,335,309	22%
2029	7314	63577	83,540,652	20%
2030	8689	75528	99,243,413	19%
2031	10228	88905	116,820,880	18%
2032	11954	103910	136,537,711	17%
2033	13679	118898	156,232,395	14%
2034	15627	135834	178,485,694	14%
2035	17751	154300	202,750,241	14%
2036	20048	174260	228,977,983	13%
2037	22561	196105	257,682,133	13%
2038	25269	219642	288,609,576	12%
2039	28232	245400	322,455,463	12%
2040	30662	266517	350,203,337	9%
2041	33186	288458	379,033,439	8%
2042	35865	311748	409,636,399	8%
2043	38734	336687	442,407,311	8%
2044	41833	363622	477,799,896	8%
2045	44761	389076	511,245,889	7%
2046	47895	416311	547,033,101	7%
2047	50768	441290	579,855,087	6%
2048	53814	467767	614,646,392	6%
2049	56505	491156	645,378,712	5%
2050	59330	515714	677,647,648	5%

Dakota Electric expects the additions of member owned solar will continue at the current pace for the next 5 -10 years. This is in line with the Medium forecast.

b) Forecast of Member Owned Energy Storage System Interconnections

Dakota Electric has seen more members install energy storage systems in 2023 than previous years. Prior to our last IDP filing, there were only a handful of energy storage systems interconnected to Dakota Electric but, during the preparation of this IDP Report, we reviewed data and note that there are now approximately 30 systems interconnected or approved for interconnection. Before 2022, there were less than 10 energy storage systems interconnected and, in just the first half of 2023, there have been 10 energy storage systems interconnected or applied for interconnection. All these energy storage systems are being used for emergency backup/outage protection and are also installed along with a solar system.

While energy storage systems are very expensive to purchase and install, the federal tax incentives in the IRA, state grant opportunities, and increasing competition from manufacturers providing additional system option is placing downward pressure on the effective cost of installation. These market dynamics are expected to increase demand for new installations. Dakota Electric has heard from some renewable energy developers that they are planning on leveraging federal tax and grant opportunities to help market standalone ESS systems or adding them to sites where members already have solar systems.

In light of these recent developments, Dakota Electric is exploring ways to utilize these energy storage systems to help reduce power supply costs and provide financial benefits to the members who install qualified energy storage systems. One of the issues with the utility use of a "behind the meter" energy storage system is the energy that is lost in charging and discharging the battery. It has been reported that most home energy storage systems only provide 70% of the energy which they store,[9] in other words, they experience approximately 30% energy loss. If Dakota Electric were able to control a member's energy storage system, up to 30% of the energy that is passing through the utility meter to recharge the energy storage unit could be lost. This would result in a significant cost for lost energy recorded by the meter.

Another issue with utilizing the full capacity of a member's energy storage system is loss of life. While batteries incur a natural degradation of as much as 2 percent a year of total capacity loss, even without using the battery, if the batteries are used more often, or deeply discharged, the loss of life can be more rapid. To maximize battery life, the typical advice from manufacturers is that the battery should not be discharged below 20% of the rated capacity. Thus, only a percentage of the total rated capacity of the battery is available for any utility program.

There are also other uses of ESS beyond power supply cost reductions. These use cases are for grid support, and they have been implemented using utility scale energy storage systems and, in some cases such as in California, using behind the meter ESS. These grid support uses cases, referred to in MISO as ancillary services, include:

- Spinning Reserves: provided by resources already synchronized to the grid and able to provide output within 10 minutes.

[9] NRECA "The Value of Battery Energy Storage for Electric Cooperatives" January 2021 – Page 9

- Supplemental (non-spinning) Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.

- Regulation: provided by specially equipped resources with the capability to increase or decrease their generation output every four seconds in response to signals they receive to control slight changes on the system.

For these grid support functions to provide proper value to the market, all these ancillary services require fast response of the DER and high-resolution metering to document the response of the DER. The metering is required to capture and save the energy consumption and output of the DER, and this metering must occur at least every minute. Regulation services may require faster data capture rates. The 1-minute data capture is required to prove that the DER device responded to the terms of the ancillary service requirements. Because of these requirements, the costs involved with controlling and metering individual small residential energy storage systems can be more costly than the payments received for providing the ancillary service.

Dakota Electric, in conjunction with Great River Energy, is looking at ways to obtain value using energy storage. Currently, demand response is seen as one of the fastest ways to get value from energy storage. Providing ancillary services for the grid are possible, but, currently, the costs for behind the meter energy storage may not economically support that effort. However, as MISO markets evolve, there may be opportunities in the future to provide ratepayer value, and Dakota Electric will continue to work with Great River Energy to explore possible options.

c) Costs involved with DER Interconnections

As described In Section 6 of this report, question Section A.16, Dakota Electric has worked at improving processes to reduce internal costs associated with processing DER interconnection applications. The table below shows that the average cost of processing and interconnecting DER with the Dakota Electric system has dropped by over 70% since 2018. Some of this reduction in cost was accomplished by implementing the NOVA application platform. Another significant cost reduction was found through streamlining how work orders were handled within the cooperative. The goal of this streamlining effort was for each area to handle a work order once. It is important to note that improvement in general was made possible by vendors submitting clean applications. When a vendor submits a clean application, Dakota Electric does not have to devote additional labor to resolve issues with the application and, when an installer is ready for witness testing, it eliminates the possibility of multiple trips to the site to complete the final testing of the interconnection. Dakota Electric commends these vendors and installers for collaboratively improving the interconnection process.

Table 6. Interconnection Costs for Member Owned DER Systems

Category	2018	2019	2020	2021	2022
# of Interconnections per year	40	98	138	371	322
Total DEA Costs	$57,437	$111,390	$146,066	$186,009	$175,627
Average DEA cost per DER	$1,436	$1,137	$1,058	$501	$545
Total Receipts	$4,700	$11,818	$23,924	$55,467	$53,180
Average Receipt per DER	$118	$121	$173	$155	$140
NET Total Cost to Dakota Electric	$52,734	$99,572	$122,142	$130,542	$122,447
Net Dakota Electric's Cost Per DER Interconnection	$1,318	$1,016	$885	$352	$380

The information in the table above shows that the average cost for interconnection increased during 2022. Dakota Electric reviewed the data associated with interconnection and believes this is driven in part by a couple new vendors beginning work in the Dakota Electric service territory and their applications required multiple revisions. In addition, upon receiving notice of completion of installation and scheduling of testing, Dakota Electric observed that the systems were not installed per the submitted one-line, which required additional, multiple visits to the site for re-testing.

d) Improvements in DER Interconnection Process and Tools at Dakota Electric

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, 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 do 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 12. 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

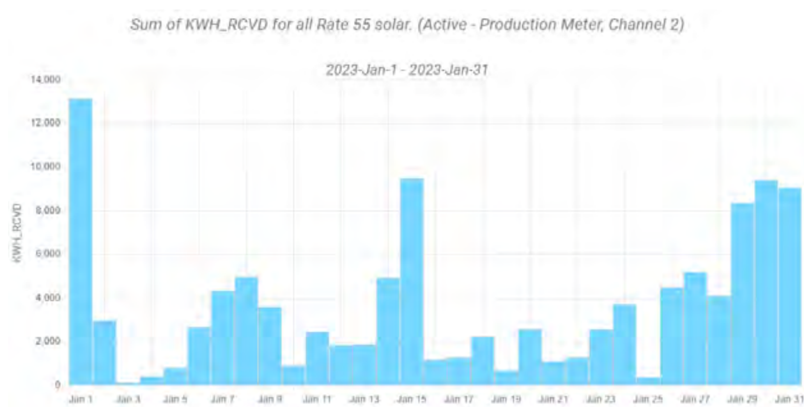
Given the low penetration of DER on the Dakota Electric system, this tool is working well and allows quick review of a DER interconnection application. As members contact Dakota Electric, we are able to easily review for capacity issues with their potential DER interconnection. As the penetration of interconnected DER increases, there will be a need for a more robust tool, but for the time being, this tool is helping provide a quick review. As we prepare for the future, Dakota Electric is researching Advanced Distribution Management System (ADMS) and similar tools which will do a more complete engineering study of interconnected applications.

e) 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. Along with the higher penetration of DER integration, Dakota Electric will need to develop 8,760-hour modeling of the distribution system and incorporate data from the AGi advanced meters within that modeling. Dakota Electric will also need to implement an ADMS with real-time modeling to support engineering analysis and to provide a tool for its control center operators. This additional data and system functionality is 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) will become unreasonable to forecast or provide operating plans to support. Thus, a robust, real-time model will be required to provide the control center 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 16. Solar DER Output January 2023 – Production Meters

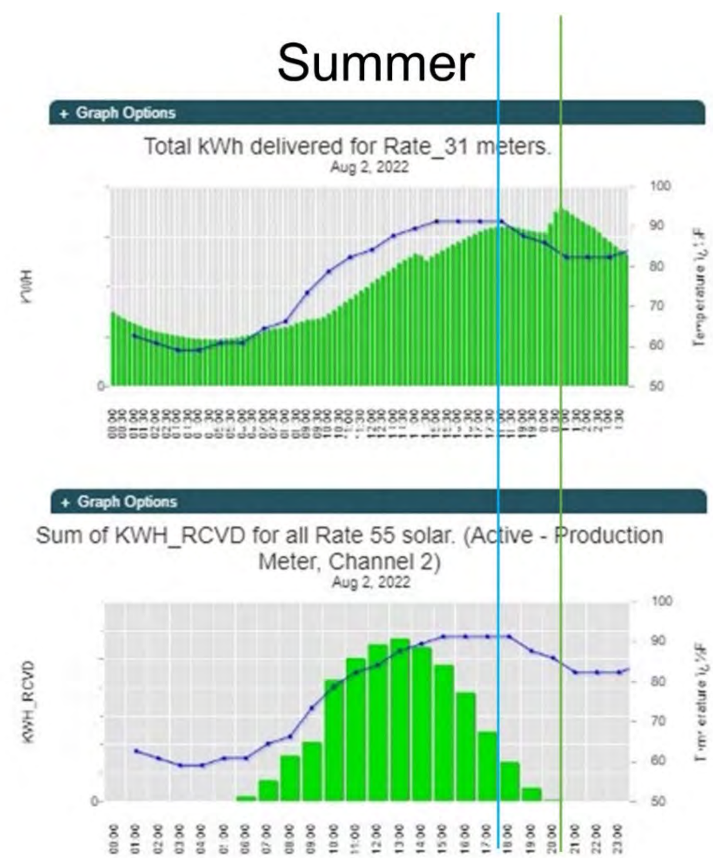


Thus far, the data captured shows that even with many aggregated solar installations, there is a common loss of output due to snow cover in the winter and cloud cover in the summer. The variability of solar output can be seen in the above graph from January 2023. This graph represents over 1,000 individual solar installations on member homes, which are located across the Dakota Electric distribution system. This loss of output is especially coincidental during the winter when cold fronts come across Minnesota and are typically associated with snowfall which covers the solar panels.

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.

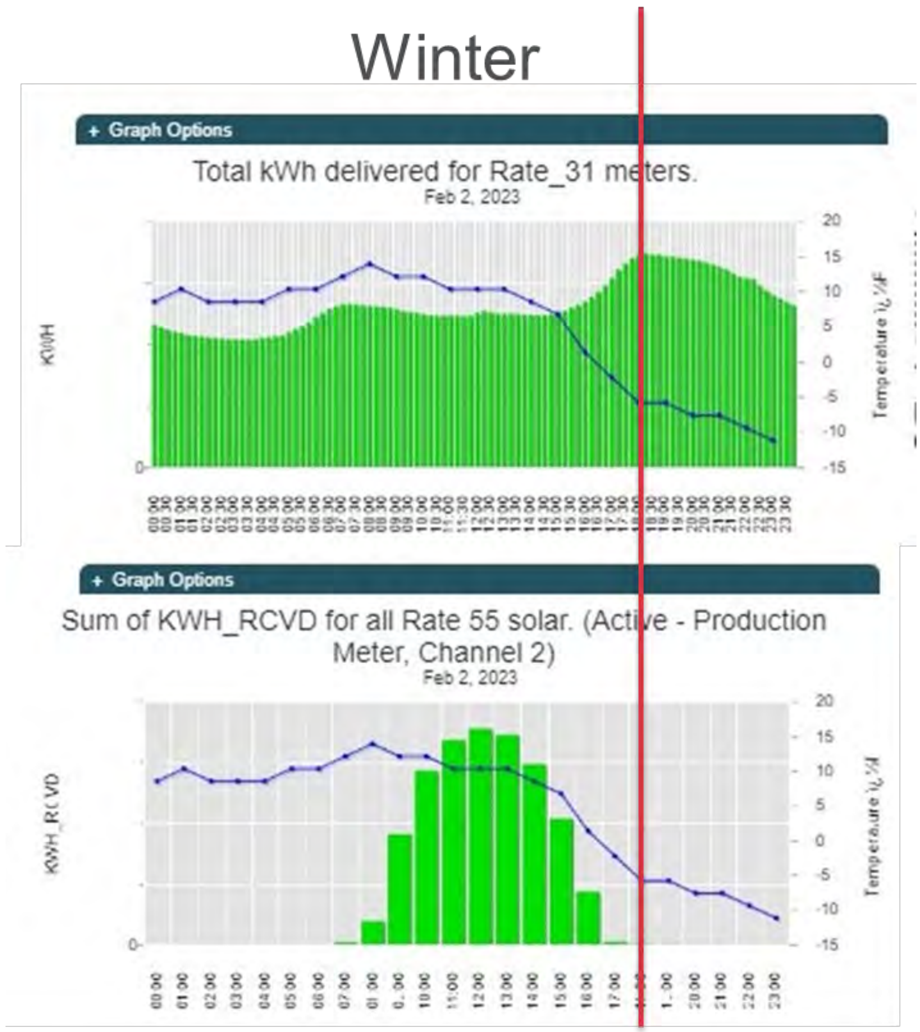
Below are two graphs, the top graph shows the total load curve for all the residential members on the Dakota Electric system, and the second graph is the sum of all the energy produced by the member owned solar systems. The top graph is a hot summer day where load control was implemented to reduce the 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 red 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 13. 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 14. 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 if any support provided by member owned solar coincident with their peak demand.

With the addition of electric vehicle charging, we have started to observe a shift in when peak demand occurs on the distribution system. With the need to environmentally condition the 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.

f) Discussion on Potential Barriers to DER interconnection

In its 2021 IDP report, Dakota Electric provided discussion about potential barriers which may limit higher levels of DER integration on the Dakota Electric system. One of these potential barriers is the cost of upgrading transmission systems to support back feeding of the transmission system due to DER interconnections on the local distribution system. The issue of back feeding the transmission system remains a potential barrier as the cost to upgrade transmission to support power injections is a significant expense. Since the 2021 IDP Report was filed, there has been additional engineering analysis completed on the transmission limitations with 3-terminal lines and changes are ongoing with MISO processes and rules for approving injections into the transmission system. Dakota Electric provides further discussion on two transmission related issues below.

Three-Terminal Transmission Line Limitation

In Dakota Electric's 2021 IDP Report, there was discussion about the limitations for injecting power onto 3-terminal transmission lines by distribution interconnected DER systems. The 2021 Dakota Electric IDP report stated the following:[10]

> There are also some substations that before any back feeding of the transmission is allowed, very expensive upgrades to the transmission protection system are required to allow safe back feeding.[11] The costs for these upgrades are in the millions of dollars. For example, four of Dakota Electric's substations are supplied by the same 69kV transmission line. This transmission line has three existing transmission sources and is referred to as a "3-terminal" line. Most transmission lines have only two sources. For a 3-terminal transmission line, the ability for each of the sources feeding the transmission line to quickly identify when there is a fault on the line, is more difficult than for a typical two source transmission line. If each of the three transmission line sources are not opened expeditiously, the safety of the public is compromised and the overall effect of the fault on the rest of the transmission system is negative. The protection settings on 3-terminal lines are specially analyzed and calibrated to ensure a safely operated system.
>
> When a substation, which is connected to a three terminal transmission line, back feeds the transmission line, that substation becomes a new fourth source into the transmission line. The back feeding (fourth source) from the substation causes the

[10] 2021 Dakota Electric IDP Report, Page 79

[11] Additional information is available in the Dakota Electric September 15,2021 IDP Stakeholder presentation, Slide 50, showing protective relaying zones for a 3-terminal transmission line with and without a back-feeding substation and the hole in protection which is created by the back-feeding substation.

protective relaying on the transmission line to become unable to identify (see) faults. If one or more of the sources cannot see, or identify, a fault, it may not quickly trip and interrupt the flow of energy into the faulted transmission line. In the event that the transmission line falls to the ground, it is critical that ALL sources supplying electricity into the transmission line are quickly interrupted. A transmission line with four sources is unable to be quickly, and safely, cleared for a fault on the transmission line, which is a significant safety hazard.

In 2022, after learning of the high costs and negative economics with owning and operating substation energy storage, Dakota Electric reached out to Great River Energy to see what other options were possible to allow back feeding of a 3-terminal transmission line. As part of that extensive review, Great River Energy transmission protection engineers modeled inverter-based DER interconnected with the Dakota Electric distribution substations which are supplied by a three-terminal transmission system. Through this analysis, it was determined that, given the limited fault current generated by inverter based DER systems, the ability of the existing transmission relaying was not negatively impacted to a level such that the transmission line protection would not function properly to safely de-energize the transmission line. This was important news and, in many cases, reduced the barrier that 3-terminal transmission lines created for integrating additional DER with the distribution system. While this was an interesting development, the significant costs of transmission upgrades due to current injections from distribution substations into the transmission system remain a potential barrier. In addition, the long lead times to complete transmission upgrades remain a future barrier when higher levels of DER penetration occur on distribution substations.

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 for the past year 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 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, the area transmission utility is Great River Energy. 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” after several stakeholders submitted comments to MISO in an effort to reduce redundancy with existing study processes. 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. The actual cost for most studies have been less than $10,000 and 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 the DER is 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 the most 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 Pilot Knob as reported in Appendix A. The minimum load at this substation has decreased over the past few years; in particular, the minimum load reported in 2022-2023 is only 72% of the substation minimum load reported in 2018. If the load on this substation was fully offset by DER interconnections in 2018, there would now be excess DER generation causing injections into the transmission system. It is also possible that distribution devices on the individual circuits may be overloaded by the energy generated by the DER systems and back feeding on those distribution devices. These devices would be required to be replaced to support the DER operation or the previously DER approved for interconnection would need to be curtailed during minimum load periods. Neither one of these operational responses is preferred.

Table 7. Example of Negative Load Growth in Feeder and Substation Minimum Loads

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2022	2020	2018	2022	2020	2018	2022	2020	2018
Pilot Knob (19)	Substation	11,154	11,762	12,773	1,741	2,311	2,408	2,418	3,323	3,183
	1				255	264	257	363	402	356
	2				244	240	233	298	249	275
	3				176	200	218	223	210	268
	4				222	886	306	222	1,114	318
	5				644	647	697	891	895	894

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.

g) Discussion on Substation Energy Storage Project in Support of DER

In the Commission's September 9, 2022 Order in Docket No. E111/M-21-728, the Commission ordered the following in Ordering Point No. 3:

> Required Dakota to file, in its next IDP filing, a thorough discussion of the installation of a utility-operated energy storage system (which would be charged with energy that would otherwise cause back-feeding during the day and that would then discharge that energy in the evening) in light of recent state and federal infrastructure programs. The discussion must include how to calculate cost to benefits impacts and how such storage solutions affect its wholesale power supply contracts and obligations.

The analysis and discussion below respond to the Commission's Ordering Point on this topic. Dakota Electric breaks its response into separate sections to aide in the review of this topic.

<u>Use of Energy Storage to help Reduce Transmission Injection Barrier</u>

The Commission requested that Dakota Electric review and analyze the use of energy storage systems (ESS) to help maximize the ability to interconnect DER with the distribution system which would otherwise be limited by transmission back feeding restrictions. This use case for ESS would be through reducing, or eliminating, energy injections into the transmission system to avoid high-cost transmission upgrade costs required to increase allowed back feeding levels.

The concept is to use an ESS to absorb energy that would otherwise cause back feeding of the transmission system above an approved level. The ESS would be installed at the substation or on a circuit supplied by that substation. The expectation is that the energy storage will charge the batteries when the DER on the impacted substation is generating sufficient energy to back feed the transmission system. The Battery Energy Storage System (BESS) would then discharge in the evening, or at night, when the DER is not generating excess energy. This concept assumes an ESS can be installed with enough capacity to store energy when the transmission system does not have capacity to support the DER export above the native load on a substation.

The process to establish the level at which a distribution substation is allowed to inject energy into the transmission system is created by transmission studies. This back feed limit depends upon the capacity of the transmission system to support injections. The study to identify the limit will include injections of energy at other, neighboring substations which have received prior approval. When beginning this process, it is important to note that there is a possibility that no injections of energy into the transmission system will be approved without paying for transmission upgrades. Typically, transmission upgrades are expensive and would likely have a negative impact on the cost-effectiveness of the ESS.

To support the use case of an ESS controlling the back feeding level at a substation, a control system would need to be established to cause the ESS to automatically absorb energy when the native load on the substation nears the established transmission injection limit. Using this real-time signal, the ESS would modify its energy absorption level to keep the substation from back feeding the transmission system above the approved limit. The ESS would need to be sized to ensure that there is sufficient capacity, each day, to absorb all the potential excess energy available from DER interconnected to the substation. The substation would also need to have enough native load connected, so that the ESS totally discharges the absorbed energy each evening.

The ESS would also need to be able to support sufficient charge/discharge cycles so that it is ready daily to absorb excess energy. Thus, daily cycling of the ESS may be required. Many energy storage systems degrade over time as they endure more and more charge/discharge cycles. When selecting the chemistry and type of ESS to install, it is important to fully understand how the ESS will need to be operated.

Since the level of native load on the substation and DER production, especially solar, changes from day-to-day, and season-to-season, the relationship between the amount of native load and the amount of DER energy generated must be considered and understood. For some cases, there could be days, or even seasons or long period of time, when no absorption of excess energy is required. This would reduce the need for daily cycling of the ESS and could have a positive impact on the long-term availability of the battery. Having a solid understanding of native load versus DER generation throughout the year is very important, because the more an ESS is completely charged and then discharged, the sooner the batteries in the system will require replacement. The costs involved with battery replacement are significant and would drive the overall economics.

<u>Types of ESS</u> – There are several different types of ESS, and battery chemistries, which can be selected for use. Dakota Electric has not completed a full review of all ESS types and chemistries, but, through our research, we have learned that this market is complex and constantly evolving. One type of ESS which appears to be very promising is flow batteries. In these batteries, liquids are stored and pumped through a reactor for charging or discharging of the ESS. There are many different types of flow batteries, and each can use different chemistries for electrical energy storage. In our research, some of these flow batteries do not appear well suited for operation in the Minnesota climate because they are not rated for operation in temperatures significantly below freezing and require heating when not in charge/discharge operation. If the fluid (electrolyte) freezes, then the elements participate out of the fluid (separate) and the flow battery is no longer functional. Clearly, this is something to avoid, so auxiliary heating is required when ambient temperatures fall below a certain temperature level. As part of this auxiliary heating, there may also be a need for special climate-controlled structures, which significantly drives up the overall capital and annual

operating costs. One of the flow battery models being planned for installation by Great River Energy and Xcel is rated for ambient temperatures down to -40C (-40F).

The other BESS chemistry which is gathering widespread use is lithium-iron batteries. There is a shift to Lithium-iron because this chemistry is reported to be better than lithium-ion batteries as they are less prone to combustion and thermal runaway. These batteries also claim to have longer cycle life. Vendors have informed Dakota Electric that lithium-iron batteries can be fully charged and fully discharged and will have significantly less degradation versus Lithium-ion batteries. With both battery chemistries (Lithium-iron and Lithium-ion), the general rule of thumb is to not discharge them below 20%; however, with lithium-ion batteries, there is a recommendation to limit recharge above 80% of the rating because additional degradation of the battery will occur when recharged above this level. Lithium-iron chemistry is not reported to have this upper limit.

2021 ESS Review - Dakota Electric began the initial review of a substation-based ESS use case concept in 2021 but did not reach a point where it was necessary to develop a full economic analysis detailing the cost/benefits of this potential solution. Dakota Electric did not conduct a more detailed analysis because, at that time, a simply review of readily available information made it was clear that the cost of this solution would be unreasonably high and the costs were significantly greater than the benefits. The other issue we encountered was that concurrent with our bid request, there were a significant number of utility scale energy storage projects being quoted by vendors. This greatly limited the availability of vendors willing to simply bid on smaller projects such as what was required for Dakota Electric's use case.

When completing the review of substation energy storage feasibility, we observed additional issues. One of the problems identified was sitting substation energy storage and the lack of available space within the existing substation. The expectation was that with the small amount of energy storage capacity required, there would be space within the existing substation footprint to site an ESS. However, after reviewing the topic in greater detail, it was found that energy storage space requirements were greater than expected. In most cases, the existing substations are built to safely contain the existing equipment and additional space is not available to site a large ESS. The space requirements for energy storage, with enough capacity to meet the requirements, is significant. For example, a 3 MW flow battery, with 6-8 hours of capacity, would need around an acre of land. To site an ESS of sufficient size, additional land would need to be purchased and developed. In urban areas, finding land available for development for hosting energy storage would be difficult, expensive, and require special permits.

Another issue with co-locating a BESS with existing substation equipment, or within an urban environment, is the risk of fire from the BESS. The fire risk and potential for damage to existing substation oil-filled transformers is risky unless sufficient space separation could be provided between the BESS and other oil-filled substation equipment. Although, as discussed above, certain newer battery chemistries have reduced fire and thermal runaway risk, the fire risk still exists, and it is likely that a BESS would be expected to result in additional permitting issues due to adject homes and business. Siting BESS in rural areas would likely have fewer land acquisition and permitting issues, as there is undeveloped land available, and it is possible to site a BESS a distance from existing structures.

<u>Estimated Benefits and Issues of using ESS to Control Transmission Back Feeding</u>

The main purpose of the ESS in our analysis is to absorb excess energy that would normally be injected into the transmission system. With the possibility that excess energy will need to be absorbed on any day, the ESS needs to be "unloaded" or, more correctly, discharged before the possibility of the DER generating excess energy. This means that the ESS use case requirement to have available unloaded capacity, limits several of the possible ways to use the ESS and receive monetary benefits. The following is a discussion of the different ways an ESS could receive compensation while achieving the goal of this analysis, which is to avoid injection of energy into the transmission system.

In addition to preventing injection into the transmission system, there are several potential uses of energy storage when installed at a location on the distribution system. Dakota Electric discusses a number of these potential uses below.

<u>Outage Protection</u> – This would be applicable for a behind the meter ESS that is installed at a home or business to operate like an Uninterruptible Power Supply (UPS). UPS are installed such that there is zero interruption in power supply to the loads which are protected. In contrast, the ESS analysis in this report will allow a brief loss of power to the loads and then transfer the supply from the utility to the ESS. Beyond this temporary outage condition, an ESS installed on the distribution system is not able to realistically provide outage protection to homes and businesses on the distribution system. This inability to provide outage protection is due to the capacity required to reliably support all the load for a distribution circuit. If a utility were to specify an ESS for this use case, it would be extremely costly as it requires an unrealistically large ESS.

<u>Creating an Unsafe Operating Condition</u> – Using a utility scale ESS to provide outage protection for a substation creates an unsafe operating condition. The entire electrical distribution system operates at 60 hertz frequency. The power on one substation naturally operates at the same frequency as its neighboring substations. Where the wires from the neighboring substations are interconnected via an open switch, the energy on each of the wires is normally designed to be "in sync." This condition makes sure that when an open switch is closed, the two separate systems will naturally operate together. When one of the substations, or wires, is supplied by

an ESS (independent source), the wires are no longer “in sync” and, if that open switch between wires which are not “in sync” is closed, there could be a catastrophic failure of the switch and the two systems could be damaged. When considering neighboring substations, there can be hundreds of normally open connections between them; as such, having independent sources would, in fact, become a serious safety issue for line workers, especially when working to restore power during a storm, because of the real potential of a not “in sync” situation.

<u>Demand Reduction (Capacity)</u> – Dakota Electric’s wholesale power costs are based in part on monthly demand (kW) coincident with the Great River Energy peak demand for that month. Great River Energy works with its member cooperatives to control, and minimize, that monthly coincident peak to save costs for all its members. If the ESS is sized properly, Dakota Electric could use this ESS to reduce the monthly demand charges which are billed to Dakota Electric. However, there are two issues associated with that strategy. First, since the ESS in this analysis is primarily to prevent export of energy onto the transmission, it is important to remember that Great River Energy peak demand occasionally occurs during the morning hours. In these instances, the ESS would already be discharged during the morning peak and would not be available to discharge energy to reduce the peak. The second issue is cost shifting. Simply reducing Dakota Electric’s demand during the Great River Energy peak does not always provide savings for Great River Energy. Instead, while Dakota Electric would receive a reduction in power costs for that month, the other members of Great River Energy would see their monthly costs increase. As a cooperative organization, the member utilities and Great River Energy work together to identify ways to reduce actual costs and not just shift cost from one member utility to the other members. If Dakota Electric were to pursue a utility scale ESS, we would instead work with Great River Energy to find ways to use the ESS in a way that reduces overall costs for Great River Energy and the other member cooperatives. The following are some of the potential ways this could be achieved.

<u>MISO Load Modifying Resource (LMR)</u> – An ESS could qualify for a load modifying resource credit within MISO. The unit would need to be registered within MISO and be ready to discharge for at least 4 hours at its registered kW level. The problem with using an ESS as a MISO LMR resource, and an absorption device for excess DER energy, is that the ESS could be at a discharged state when requested to provide 4 hours of discharge to support the grid. This would make registering the ESS for the MISO LMR program difficult, if not, impossible. Once a device is registered as part of the LMR process, it must be ready to respond within 2 hours of a request for operation. There are possible exemptions of this 2-hour response, but the benefits of using an ESS for LMR versus the risks of not being able to perform could be significant.

<u>Energy Arbitrage</u> – Since the ESS will be charging during daytime hours to absorb excess solar generated energy, and then discharging during the evening demand periods, there could be a cost of power difference, commonly referred to as arbitrage, between the energy used for charging and the potential for higher prices paid when discharging. If we look solely at wholesale power costs, there could be energy benefits for charging the ESS during the

afternoon or morning hours and then discharging over the evening hours. The table below presents a simple economic analysis with the following assumptions:

- Afternoon MISO wholesale energy costs, on average are greater than early evening energy costs;
- ESS is cycled using only 70% of capacity to avoid excess degradation of the battery;
- 15% loss of energy during the charge/discharge cycle on the ESS;
- $30/MWHR average cost of energy lost; and
- Net Benefit calculation is Energy Released (@ $X benefit) – Cost of lost energy.

Table 8. Value of ESS with Energy Arbitration & Reducing Transmission Back-feeding

	Daily	Yearly
Energy Consumed	12,600 kwhr	4,599 MWhr
Energy Released	10,710 kwhr	3,909 MWhr
Cost of Energy Lost @ $30	$56	$20,700
Net Benefit @ $10 average difference	$51	$18,390
Net Benefit @ $20 average difference	$158	$57,488
Net Benefit @ $30 average difference	$265	$96,579

The table above assumes a relatively large $30/MWHR average daily wholesale power cost differential and, even with this large differential, there is only a $96,579 annual net benefit. Using a more realistic, but arguably still optimistic $10 per MWHR average wholesale cost differential, there is only a $18,390 annual net benefit energy arbitrage.

Conceptually, beyond the relatively small benefits presented above, there is also the existing energy cost disincentive for a utility to use an ESS to support greater penetration of residential solar on the distribution system which exists because utilities in Minnesota compensate small DER production at the average retail rate and not wholesale costs. For Dakota Electric residential solar, they are paid over $130/MWHR for excess energy (retail net metering), while typical wholesale energy costs are in the $20-$50/MWHR range. The table below shows the cost to the utility for purchasing the excess energy from the residential consumers at retail rates and selling it back to the grid at wholesale prices each evening.

Table 9. Cost of Buying At Retail and Selling at Wholesale

	Daily	Yearly
Energy Purchased from Residential members	12,600 kwhr	4,599 MWhr
Energy Cost at $130/MWHR	$1,638	$597,870
Energy Released	10,710 kwhr	3,909 MWhr
Energy Payment @ $40 value	$428	$156,360
Net Benefit (Loss)	($1,210)	($441,504)

The information in the above table presents a case where the utility would lose over $440,000 per year because of the difference between average retail rates and wholesale power costs. This loss is in addition to the cost to install, own, and operate the ESS. Dakota Electric notes that the $40/MWHR average cost of energy over the evening hours is illustrative and should not be taken as a firm price estimate. This table does, however, illustrate that there are few, if any, instances where the value of the energy received by the ESS (wholesale costs) is near what is being paid for that energy from the DER system (retail net metering).

<u>MISO Grid Support – Spinning Reserve</u> – Traditionally, there has been a subset of generators on the grid that were not fully loaded and maintained spare generating capacity to allow them to quickly increase their energy output if another generator tripped offline. When a generator trips offline, the frequency drops as there is too much load on the existing rotating generators to handle and they quickly start to slow down. When a rotating generator senses a drop in frequency, the "droop characteristic" of the generator control is designed to automatically increase the energy output of that generator. In addition to this subset, there are also generators connected to a communication link with the generator control center and/or MISO control center that are available to increase their output to cover for an emergency loss of generation. This emergency capacity is referred to as a spinning reserve. An ESS can provide short-term spinning reserve services, but, in the use-case requested by the Commission, there is no guarantee that the ESS is always fully charged. Based on this fact, there will be times when the ESS is not able to respond to a spinning reserve operational request. This would preclude this ESS from participating in this MISO market or significantly impact their value potential in the MISO market.

<u>MISO Grid Support - Frequency Regulation</u> – As discussed earlier, traditional generation has a "droop curve" that would automatically trigger the generator to increase output if the frequency dropped too low and decrease output if the frequency went too high. With the addition of renewable systems, many are only able to reduce output, or are not programed to modify their output at all, in response to frequency issues. In this instance, an ESS can be operated to either raise production or lower production by either charging or discharging. Many utility-scale ESS are installed and operated as Frequency Regulation systems. The issue

with using an ESS for frequency response, that is also designed to handle excess DER energy production at the substation, is that there are times when the ESS will be fully charged and times when it is fully discharged. In both cases, the ESS will not be able to correctly respond to the frequency changes. Based on this fact, there will be times when the ESS is not able to respond to a Frequency Response need. This would preclude this ESS from participating in this MISO market or significantly impact their value potential in the MISO market. It is possible to size the ESS such that a portion of the ESS capacity could be reserved for Frequency Regulation, but given the MISO payments for Frequency Response, there is a long-term economic concern as to how economical this would be.

Estimated Costs of an ESS to Control Transmission Back Feeding

After presenting the detailed introductory information and scenarios above, Dakota Electric provides the following estimated costs for the installation and operation of an ESS to control transmission back feeding at a substation. For this example, Dakota Electric assumes a 3 MW/18 MWhr system. Generally speaking, the smaller the capacity of the ESS, the greater the cost per rated kW due to siting and interconnection costs. With larger systems, there are economies of scale for siting and interconnection costs. The system size modeled by Dakota Electric represents the most realistic size specification that we believe would satisfy the Commission's request in its 2021 IDP Report Order.

The following costs for an ESS system are the same values used in the Section 4 analysis of non-traditional solutions (non-wires alternatives).

- Land costs for sitting 3 MW's of ESS, rural land purchase.
  - $25,000 per acre for 4-5 rural acres of land.
- $100,000 to permit and develop a substation site (*e.g.,* grading, access roads, landscaping).
- $150,000 for construction and physical interconnection of the ESS with the distribution system.
- $50,000 estimated for the control system to sense the load level on the substation and provide a signal to the ESS charge/discharge controller.
- 5% annual interest rate for Net Present Value Calculations.
- Energy Storage System Costs.[12]
  - $888 Per kW for energy storage infrastructure.
  - $216 Per kWhr for energy storage capacity.
  - 10-year useful life for energy storage before refurbishing.
  - $48 / kW for ESS annual operating costs.

[12] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage - NREL 2022 baseline, Utility Scale Battery Energy Storage - 2025 Moderate forecast – 20-year cost recovery period – 6 hour Capacity.

Table 10. Estimated Cost of 3MW/18MWHr ESS Installation

Description	Cost 2023 Dollars	Present Value @ 5% rate
Acquire Land (4 acres)	$ 100,000	$ 100,000
Permitting and Development of the Site	$ 100,000	$ 100,000
Control System	$ 50,000	$ 50,000
Energy Storage (3 MW - 18 MWHr)	$6,552,000	$6,552,000
Operating Costs		
Maintenance	$1,440,000	$1,111,930
Total Costs	$8,242,000	$8,006,754

Looking at the cost for installing and operating an ESS and, given the limited ability to use the ESS for both absorbing the excess DER generated energy at the substation and for other use cases such as MISO grid support services, the overall costs suggest that this is not an economic method for supporting additional DER integration with a distribution system that is limited in its ability to back feed the transmission system.

Behind the Meter Energy Storage

The high cost and limited economic benefits of utility scale energy storage to support the integration of DER led Dakota Electric to examine the use of ESS installed at individual DER systems as a potentially better application of energy storage. The behind the meter (BTM) ESS could be used to reduce, or eliminate, excess energy being pushed back to the distribution grid. This would also support a better match between energy production and local energy consumption. Further, the BTM ESS system would be able to provide outage protection for the home and, if installed to work with the solar DER, could enhance the outage protection for at least a portion of the home's electrical needs.

Through the use of existing utility TOU rates, an ESS coupled with a solar system can be used to reduce a home's energy usage during higher priced periods. This is especially economically beneficial if the homeowner is able to shift use of more energy intensive appliances, such as dishwashers and clothes washers, to the lower priced off-peak periods.

Both of these use cases are supported within current utility rules and rates. However, given the upfront cost of a BTM ESS and available TOU rate options, there is currently little economic support for a homeowner to install a BTM ESS. Even with the current federal and state tax incentives, energy storage remains expensive. Since there is currently no cost to use the distribution grid for back feeding of excess energy, and the homeowner is fully compensated through retail net metering credits, there is no incentive, or economic reason, for a consumer to reduce their impact on the grid. In addition, as part of the current DER interconnection process, adding energy storage to a solar system increases the cost of interconnection fees and energy storage can result in the loss of the net metering option if the combined capacity of the system is above the net metering threshold. These observations raise important questions about whether changes to how combined solar and storage systems are treated for the interconnection process and whether it is appropriate for utilities to consider rate programs or incentives for BTM energy storage.

4) ANALYSIS OF NON-TRADITIONAL SOLUTIONS (NON-WIRES ALTERNATIVES)

Dakota Electric has employed what is 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, our membership saves over $15 million dollars in power costs each year through the operation of the 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 1960s, 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 approach or exceed two (2) million dollars. Dakota Electric notes that it has also applied for, or is actively considering, grant and funding opportunities through the IIJA and IRA which may also involve projects in excess of $2 million. Since these potential investments are contingent upon a grant award, Dakota Electric does not provide additional discussion at this time.

The following is a summary of the large projects, which are included in the capital dollars, followed by a more detailed analysis for each of the projects listed.

1) The first project identified is the sitting and construction of a new substation near Elko-New Market, Minnesota. This project was reviewed in the 2019 and 2021 IDP reports and below is an updated review of the non-wires solutions versus the construction of a substation near Elko-New Market. Construction of this substation has been delayed due to extended lead times and coordination schedule extensions involved with interconnection of the substation to Xcel Energy's transmission system. The energization date for this substation is currently December 2024.

   This analysis looks at using non-wires (non-traditional) methods instead of building a substation or delaying the construction of this substation. This analysis provides a generic comparison of using non-wires solutions to eliminate or delay distribution substation capital expenditures and provide reliable electricity for our membership as the issues are similar for any new distribution substation.

The Dakota Electric service territory around Elko-New Market is currently supplied by a substation which is several miles north of the future load center. The existing substation and the associated feeders connecting the Elko-New Market service area to the substation have a limited amount of unused capacity. The neighboring substation is many miles to the east and has limited capacity to provide energy in the event of a contingency, such as the loss of the primary substation. The service area in need of additional capacity is adjacent to Interstate 35 and is prime commercial development. Since the 2021 IDP analysis, a major manufacturing plant has been approved and is expected to be on-line in 2024. The existing substation, with additional feeder development, will be able to meet the normal electrical requirements of this one new load for 2024. However, a new substation is required, and is planned for late 2024 completion, to reliably supply this load and the future load growth in the area.

2) The second 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 the 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 fail and whether that non-wires solution is able to meet the reliability and capacity needs during time required to repair/replace the failed substation equipment.

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 generators 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 the 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 that same level of reliability.

4) Enter into a contractual relationship to provide the service of the DER. Dakota Electric needs to provide 24/7 electricity to our membership. As a result, all portions of the distribution system must be designed, and built, so that we have a way to supply electricity in the event of equipment failures. One place where DER systems could provide a benefit is during these contingencies. Upon failure of a portion of the distribution system, the DER would provide energy to an area while the failed equipment is replaced or maintained.

Once a decision is made to forego rebuilding a distribution circuit or adding a new substation, instead relying upon the DER system(s) to provide electrical energy, this is a long-term commitment by the DER system(s). It is important to understand that if a distribution substation is not built prior to the 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. Even adding or replacing circuits involves permitting/routing time considerations, so the DER will be required to make a long-term commitment to maintain the operation of the system.

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

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 that 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.

Renewable Energy Systems: The cost of renewable energy projects, including energy storage, has been impacted by supply chain issues and overall increased demand. With the significant federal funding dollars available in support of renewable projects, 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, especially in the solar market prices. All the costs for renewable energy systems are based upon the NREL 2022 forecasts, which are available on the web, under the annual technology baseline.[13]

Solar Systems: The costs of solar systems were dropping as better designs and improvements in the costs of the components were occurring. However, as with all the renewable energy systems, recent demand and supply chain considerations have affected the cost of these systems. The following costs of utility scale solar for 2025 installations are from the NREL 2022 forecasts, which do not fully incorporate the high costs of renewable energy systems.

Table 11. Utility Scale Solar Costs

Utility Scale Solar[14]	
$/kW	$981.7
Annual O&M costs $/kW-yr	$18

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 in that size and, after providing the quote, could not hold that price outside of a 30-day window. 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 2022 NREL Annual Technology Baseline report. The numbers are the 2025 forecasted costs from the 2022 study. The NREL

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

forecast is based upon 2021 costs and does not reflect 2023 cost increases. The O&M costs include round-trip energy losses and replacement of failed equipment.

Table 12. Utility Scale Energy Storage Costs

Utility Scale Energy Storage[15]	4-hour Storage	8-hour Storage
$/kW	$1,104	$1,968
Base $/kW[16]	*$888*	
Capacity $/kwhr[4]	*$216*	
O&M $/kW-yr	$27.6	$48

Table 13. Residential Energy Storage Costs

Residential Scale Energy Storage 5kW-20kW[17]	
$/kW	$2,611
$/kW-year	$65

d) Project #1: Siting and Construction of New Substation Near Elko-New Market

As noted above, this project was initially reviewed in Dakota Electric's 2019 and 2021 IDP reports. The review below includes updated costs for non-wires solutions, land prices, and substation equipment.

As new residential and commercial buildings are constructed in and around Elko-New Market, Dakota Electric must provide service. The traditional method of providing electrical service involves adding new feeders and distribution substation capacity to bring the electrical energy from the transmission system to the new services. The following analysis assumes that wires within local residential and commercial developments are required to be run to each of the new services and that larger wires (feeders) are also required to supply business and residential developments under any scenario. This cost of local wires to each premise, connected to main feeders, is assumed to be the same and required for all the solutions analyzed. As a result of this, the cost for these wires and distribution transformers located next to the homes or business are not included in any of the scenarios. The analysis looks at the unique costs

[15] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage - NREL 2022 baseline, 2025 Medium Forecast – 20-year cost recovery period.

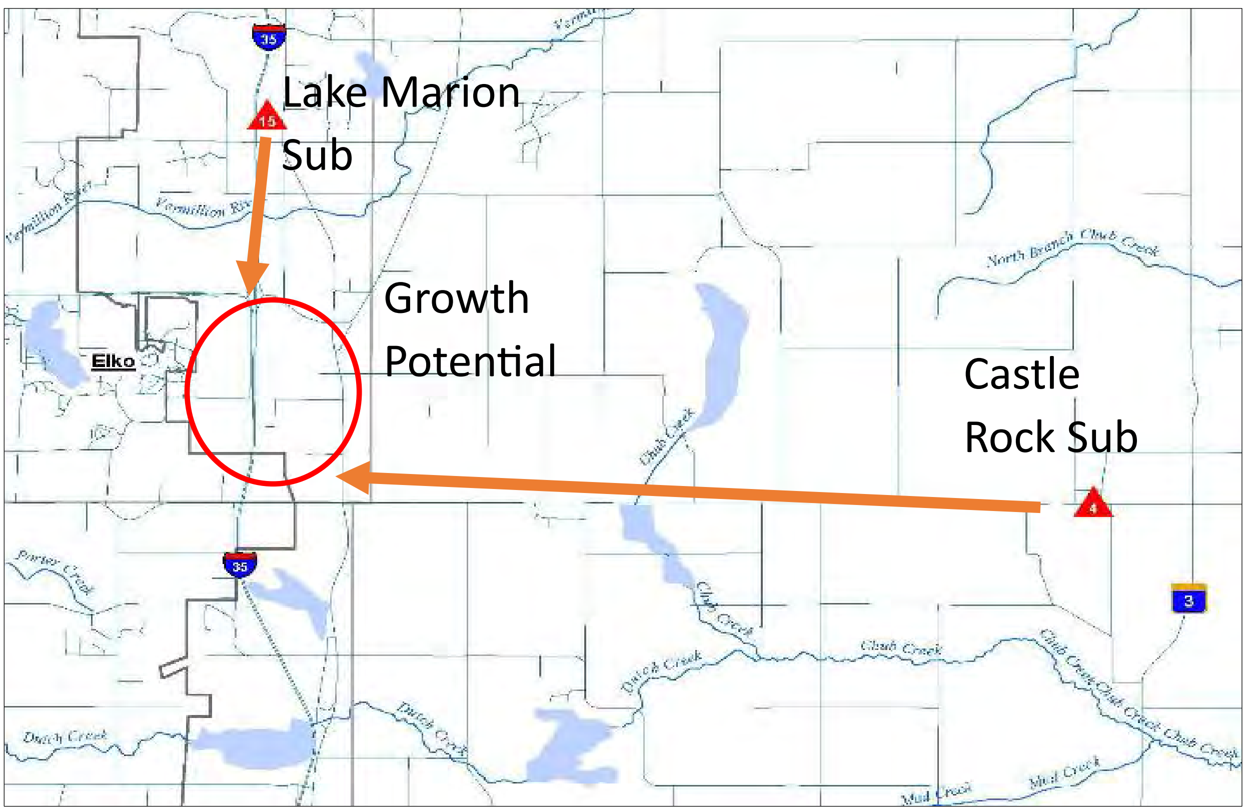
[16] Taking the different between 4-hour and 8-hour energy storage and dividing that difference by 4 gets $216. This is generally the $/kwhr of adding additional storage capacity. The remaining $888 on the 4-hour storage system is the balance of system costs per/kW. This $888/kW is in line with EIA August 2021 Energy Storage report. "Battery Storage in the United States: An Update on Market Trends."

[17] https://atb.nrel.gov/electricity/2022/residential_battery_storage - NREL 2022 baseline, 2025 numbers from the medium forecast – 20-year cost recovery period.

associated with each option which is possible to provide a reliable source of electrical energy to the membership.

As shown in the figure below, there is an area east of the city of Elko-New Market which has high growth potential. This area is presently supplied by Dakota Electric's existing Lake Marion Substation (Lake Marion), located a few miles north of this area. Lake Marion currently has some capacity to supply new loads in this area, but there will need to be more capacity added in the area to supply the growing load. The option of adding more feeders coming from Lake Marion, along with increasing the Lake Marion capacity, was considered. After reviewing this solution, Dakota Electric concluded that this option was not feasible because it does not provide a method to supply this area if there is a loss of the Lake Marion substation. If Lake Marion substation is damaged or fails, the remaining Castle Rock substation, located several miles to the east, would be unable to supply the area's load.

Figure 15. Growth Potential of Lake Marion - Castle Rock Area



Since increasing capacity using the Lake Marion substation is not a reliable solution, Dakota Electric must consider other solutions to serve the load growth in the Elko-New Market area.

Load Growth Assumptions for the Comparison of the Options

The speed of load growth in the area is uncertain. A large commercial load is approved and is planning to be energized in 2024. Additional electrical demand in this area could grow quickly, with additional commercial installations or, it could grow slowly, depending upon many factors, such as: general economic conditions, I-35 interstate access, and public opinions on new developments. Regardless of how fast the growth occurs, any solution will need to be economically justified to meet both the high and low growth scenarios. Given the uncertainty of future load growth, it is important that any solution for this area is flexible and able to meet electrical needs.

For the following analysis, there were two load growth scenarios developed. One assumes slower load growth and the other represents a faster growth scenario. The known commercial development is included in the two load forecasts. The table below shows the peak load demand values (MWs) for each load growth scenario.

Table 14. Growth Scenarios for Lake Marion – Castle Rock Area

Analysis Year	Slow Growth	Faster Growth
Year 1	5 MW	7 MW
Year 3	7 MW	10 MW
Year 5	8 MW	14 MW
Year 10	9 MW	16 MW
Year 15	10 MW	19 MW
Year 20	15 MW	25MW
Year 30	20 MW	30 MW
Year 40	25 MW	40 MW

The following potential wires and non-wires options were identified for analysis.

1A. Traditional Solution - Permitting and constructing a new 115kV substation capable of initially providing 25 MVA of firm capacity and having that installation able to easily add additional capacity.

1B. Energy Storage only - Permitting and developing a substation site, which is ready for future substation construction, but initially installing an ESS to defer the substation construction costs.

1C. Energy Storage plus Solar - Build a solar system to generate energy with an associated energy storage system to provide 24/7 energy and deferring the substation equipment installation for a longer period than option 1B.

1D. Demand Side Management - Installation of demand-side management at member homes and businesses to defer the substation construction for a period, similar to option 1B, but using distributed energy storage at member’s homes and businesses.

Summary of Assumption and Costs

Below is an estimate of the various cost considerations used for all scenarios. The analysis is a high-level (not detailed) study of benefits, costs, and risks to evaluate the different options.

- Land costs.
  - $500,000 per acre for 5 acres of land for the substation site.
  - $100,000 per acre for purchasing larger amounts of land.
- $400,000 to permit and develop a substation site (*e.g.,* grading, access roads, landscaping)
- $1,500,000 For a 115kV to 12.5kV substation transformer.
- $850,000 for a substation switchgear.
- $700,000 for construction of a substation (*e.g.,* rock, fence, high side, foundations, ground grid).
- $350,000 for construction to double end an existing substation.
- $750,000 for connection to the transmission line.
- 5% annual interest rate for Net Present Value Calculations.
- Energy Storage System Costs.[18]
  - $888 Per kW for energy storage infrastructure.
  - $216 Per kWhr for energy storage capacity.
  - 15% round trip energy losses (85% efficiency)
  - 10 years useful life for energy storage before refurbishing.
  - $48/kW for ESS annual operating costs.
  - Energy storage output is 80% coincident with Dakota Electric monthly peak.
- Solar Installation Costs[19]
  - $981.7 per kW for solar system installation.
  - $18/kW for annual operating costs.
  - 8 acres of land per MW.
  - 1,400 MWHR annual production per MW of solar installation.
  - Assumption, all solar energy credited for higher cost on-peak energy.

Option 1A – Building a New 115 kV Substation.

A new substation requires the purchase of land, permitting, development of the site, interconnection with the transmission system, and the purchase and installation of the substation equipment. Building the substation, with a transformer and switchgear, meets all the reliability criteria. The initial substation capacity would be at least 25 MW and the analysis includes doubling the capacity of the substation at 25 years to 50 MWs. Since this is using existing methods, Dakota Electric has spare equipment available to replace any failed equipment. All the Dakota Electric field technicians and line crews are fully trained to

[18] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage - NREL 2022 baseline, Utility Scale Battery Energy Storage - 2025 Moderate forecast – 20-year cost recovery period – 6 hour Capacity.

[19] https://atb.nrel.gov/electricity/2022/utility-scale_pv - NREL 2022 baseline - Utility Scale PV – 2025 Moderate Forecast – 20-year cost recovery – Class 9 Southern Minnesota Installation.

operate this standard equipment under both normal and abnormal conditions. Dakota Electric crews can quickly repair or replace any equipment used for this option.

The following is the cost for both the slow growth and the fast growth scenarios as the one solution will satisfy both growth scenarios. Comparing these substation costs to the 2021 IDP report, it is clear that substation transformer costs have doubled. This is due to limited production capacity and the current cost of metals, such as copper. Other substation costs also increased due to supply chain realities.

Table 15. Option 1A - Building a New 115 kV Substation Cost Estimates

Project Year	Description	Cost 2023 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land	$2,000,000	$2,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Substation Transformer	$1,500,000	$1,500,000
	Switchgear	$850,000	$850,000
	Transmission Interconnection	$750,000	$750,000
	Substation Construction / Misc Equip.	$700,000	$700,000
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,500,000	$442,954
	Switchgear	$850,000	$251,007
	Substation Construction	$350,000	$103,356
	Total Cost	**$8,900,000**	**$6,997,317**

Option 1B – Deferring Building a New Substation Using Energy Storage

This option is to develop a substation site that is ready for construction when required, but to defer the purchase and installation of the substation transformer, switchgear, and transmission interconnection for a few years through the use of an ESS to supply the daily peak loads. The assumption is the existing feeders, which are supplying the area from the adjacent substations, have enough spare capacity during every evening so the ESS can be recharged each night to be ready to supply the peak load the next day.

A key assumption of this option is the ESS 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 ESS to be recharged from neighboring substations. The ESS 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 15% loss of energy with the charging and discharging of the ESS is assumed. Suppliers of ESS have informed Dakota Electric that they will guarantee a maximum of 15% energy losses and, over time, that can grow to 20% energy losses due to the charging and discharging of the ESS.

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. Since the 2021 IDP report analysis, a large commercial load is planned for the area and expected to be online in 2024. The commercial load is a 24/7 operation and will likely have high-capacity demand 24 hours per day. Due to the higher demand requirements of the new commercial load, the capacity of the energy storage has been increased.

Dakota Electric assumed that this option could defer substation equipment costs for 7 years. This option also assumes the energy storage continues to operate for the remaining life of the system, 10 years, and provides energy arbitrage and power supply demand reduction benefits during this time.

Dakota Electric also considered additional potential benefits in its review of the ESS. This analysis credits the ESS for reducing 80% of the peak demand charges over traditional power supply options. The analysis also gives credit to the ESS 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 ESS through charging and discharging. For the analysis, the ESS 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 16. Option 1B - Estimate Cost for Slow Growth of Load

Project Year	Description	Cost 2023 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land (3-4 acres)	$2,000,000	$2,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (5 MW - 50 MWHr)	$15,240,000	$15,240,000
Year 7	Substation Transformer	$1,500,000	$1,175,289
	Switchgear	$850,000	$665,997
	Substation Construction / Misc Equip	$700,000	$548,468
	Transmission Interconnection	$750,000	$587,645
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,500,000	$347,066
	Switchgear	$850,000	$196,671
	Substation Construction / Misc Equip	$700,000	$161,964
	Transmission Interconnection	$750,000	$173,533
	ESS Demand benefits minus Annual Operational Costs	-$7,844,500	-$6,057,315
	Total Cost	**$17,395,500**	**$15,439,319**

The fast-growth scenario assumes a second energy storage system would need to be added in Year 3 to double the capacity of the energy storage system. In addition, the fast growth scenario also assumes that the deferral of the substation equipment expenses would only be for five years.

Table 17. Option 1B - Estimate Cost for Fast Growth of the Load

Project Year	**Description**	**Cost 2023 Dollars**	**Present Value @ 5% Rate**
Year 1	Acquire Land (3-4 acres)	$2,000,000	$2,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (5 MW - 50 MWHr)	$15,240,000	$15,240,000
Year 3	Add Energy Storage Capacity		
	additional (5MW – 50 MWHR)	$15,240,000	$13,164,885
Year 5	Build the substation		
	Substation Transformer	$1,500,000	$1,175,289
	Switchgear	$850,000	$665,997
	Substation Construction / Misc Equip	$700,000	$548,468
	Transmission Interconnection	$750,000	$587,645
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,500,000	$565,334
	Switchgear	$850,000	$320,356
	Substation Construction / Misc Equip	$700,000	$263,823
	Transmission Interconnection	$750,000	$282,667
First ESS	ESS Demand benefits minus operational costs	-$7,844,500	-$6,057,315
Second ESS	ESS Demand benefits minus operational costs	-$7,844,500	-$5,494,163
	Total Cost	**$24,791,000**	**$23,662,986**

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, under both growth scenarios, the amount of energy which could be unserved by the existing infrastructure could be large. Given this fact, the energy capacity requirements of the ESS 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 $6.98 million and the lowest cost Option 1B scenario at $15.4 million are sufficiently large that additional detailed analysis of Option 1B was not warranted.

In addition to the higher costs of Option 1B, the option using energy storage has additional reliability and resiliency risks over the traditional substation construction. There are significant risks when relying on the ESS 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 reliability supply the load using the ESS.

- Failure of the ESS – The repair time for replacing a failed component within the ESS is unknown. Getting spare components to repair a portion of the ESS would be a difficult process. Spare components are not readily available within hours as with traditional solutions. Due to the failure of the ESS system, some of the members in the area could go without power for an extended period of time until replacement components are available.

- The ESS must have existing electrical infrastructure available every night to allow recharging of the ESS. Without the existing wires and adjacent substations, the ESS 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.

Option 1C – Deferring New Substation Using a Solar System with Energy Storage

This option involves construction of a solar energy system to provide energy to meet the energy requirement of the new loads which are connected in the area in combination with an energy storage system to provide energy during times when the solar is unavailable. This option helps remove the risk of the adjacent substations and feeders not being available to recharge the energy storage system, but it adds significant costs. The original plan was to use the energy produced by the solar system, and the ride-through capability of the ESS, to eliminate the construction of the substation. However, as the energy and demand amounts continued to increase, the overall costs of this option escalated, especially for the fast growth scenario. As such, the option to delay the construction of the substation to a future year was added to help cap the overall cost of this option.

As with Option 1B, the sizing of the ESS is difficult as the load profiles of potential new loads are unknown and will remain as such until they are constructed, or near completion. High-level assumptions were made for the energy and capacity requirements associated with these new loads. The energy storage will need to be sized to supply the energy requirements of the loads during evenings and periods when the solar panels are unable to produce energy, such as when they are covered with snow or there is extended cloud cover. Given these disruptive events, the energy storage must be flexible and able to quickly add more capacity. In addition, both the solar and energy storage will need significant spare capacity available to serve new loads.

Assumptions

- The solar system will last for 30 years without refurbishment.
- Energy storage sizing:
    - Able to supply 50% of the peak load for 8 hours daily, also a portion of the local load for 10 hours each evening since solar production will not be possible during the nighttime hours.
    - ESS must be sized to supply 90% of the load for at least two consecutive days because of loss of solar production due to events such as snow or cloud cover.
- Production from the solar system is assumed to be produced on-peak and the costs are credited at that full value.
- The ESS reduces power supply demand charges by 90%.

The following are the costs to supply the slow growth scenario.

Table 18. Option 1C – Estimate Cost for Slow Growth Scenario

Project Year	Description	Cost 2023 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land (80 acres – Solar Farm)		
	Enough for 30 years capacity	$8,000,000	$8,000,000
	Build 2 MW's of Solar	$4,908,500	$4,908,500
	Energy Storage (5 MW - 50 MWHr)	$15,240,000	$15,240,000
Year 10	Build 3 MW's of Solar	$4,908,500	$3,013,393
	Energy Storage (3 MW - 18 MWHr)	$15,240,000	$9,356,038
Year 15	Build Substation		
	Use land purchased for Substation	$0	$0
	Development of the Site	$400,000	$192,407
	Substation Transformer	$1,500,000	$721,526
	Switchgear	$850,000	$408,865
	Substation Construction / Misc Equip	$700,000	$336,712
	Transmission Interconnection	$750,000	$360,763
	Solar Energy Production Benefits	-$13,776,000	-$6,220,344
ESS #1	ESS Demand benefits - operational costs	-$7,516,000	-$5,803,656
ESS #2	ESS Demand benefits - operational costs	-$7,516,000	-$5,264,087
	Total Cost	**$23,689,000**	**$25,250,115**

For this scenario, the present value costs are higher than the total costs, which is much different than for the other scenarios. This is due to the benefits occurring annually during the life of the project. When adding up the total benefits, absent depreciation, the total amount of benefits is a greater value. When the present value of these benefits is calculated, they are significantly reduced.

The following are the costs for the fast growth scenario.

Table 19. Option 1C - Estimate Cost or Fast Growth Scenario

Project Year	Description	Cost 2023 Dollars	Present Value @ 5% Rate
Year 1	Acquire Land (120 acres)		
	Enough for 30 years capacity	$8,000,000	$8,000,000
	Build 5 MW's of Solar	$4,908,500	$4,908,500
	Energy Storage (5 MW – 50 MWHr)	$15,240,000	$15,240,000
Year 3	Build 5 MW's of Solar	$4,908,500	$4,240,147
	Add Energy Storage (5 MW - 50 MWHr)	$15,240,000	$13,164,885
Year 5	Build 5 MW's of Solar	$4,908,500	$3,845,938
	Energy Storage (5 MW - 50 MWHr)	$15,240,000	$11,940,939
Year 10	Build Substation		
	Use land purchased for Substation	$0	$0
	Development of the Site	$400,000	$192,407
	Substation Transformer	$1,500,000	$721,526
	Switchgear	$850,000	$408,865
	Substation Construction / Misc Equip	$700,000	$336,712
	Transmission Interconnection	$750,000	$360,763
	Solar Energy Production Benefits	-$24,640,000	-$11,768,622
ESS #1	ESS Demand benefits - operational costs	-$7,516,000	-$5,803,656
ESS #2	ESS Demand benefits - operational costs	-$7,516,000	-$5,264,087
	Total Cost	$32,973,500	$40,524,315

Overall, Option 1C is much like Option 1B because the energy capacity requirements are unknown for any new loads which will request electrical service from Dakota Electric. Therefore, a large amount of extra energy generation and storage capacity is required to allow enough reserve for supplying the electrical requirements of the loads. The energy storage system capacity amounts used for this option could easily be greater than what was used for the analysis. Dakota Electric is also concerned about what would happen if the solar system's output was limited for longer than a day or two. This is not an unlikely scenario because storms could damage panels requiring weeks or months to repair. If this scenario occurred, there would be no options to supply energy to members in this area because there are no wires to carry energy to the area. The only solution would be for these members to procure their own backup generators or be disconnected for periods of time and possibly experience rotating blackouts.

As noted above, the traditional solution (Option 1A) is $6.98 million dollars in present dollars compared to $25.2 million (slow growth) and $40.5 million (fast growth) for the non-wire solution. The traditional wires solution is also able to be repaired in a short time frame with standard equipment which is warehoused by Dakota Electric and others. For these reasons, the traditional solution was selected.

Option 1D – Deferring New Substation with Demand-side Management.

This option would require Dakota Electric to work with new and existing loads to identify enough new load management to effectively reduce the system peak demands during times when the load in the area is greater than the existing infrastructure's capabilities. This would require developing new load management programs and, most importantly, the cooperation of many new and existing members to allow the control of the loads in their homes and businesses.

Assumptions

- The cost of incentives for members to accept load management is a high-level estimate. Based upon Dakota Electric's experience with load management, it is possible to get members to sign up for load management if communicating to all members across a large area. When the need is specific to a targeted area and specific to members during a short time period, such as 1 year, there must be additional incentives applied to motivate the members to sign up. This analysis assumes that it will cost $150 per kW to get members to sign up for a specific load management control program.
- There is enough load that can be identified for the load management programs to allow this option to occur.
- A combination of traditional load management using load control receivers and behind the meter energy storage is used to achieve the amount of controllable load.
- Cost per kW to install receiver-based load control is $250/kW.
- Cost to provide maintenance for the behind the meter ESS is $100/kW/year.
- Cost per kW for home energy storage installed is $3,500/kW (assuming 4 kwhr/kw installed, to provide a minimum of a 4-hour supply)

Over the past few years, due to very high demand, Tesla and other battery manufacturers have continued to increase the cost of smaller behind-the-meter energy storage systems. For example, costs of over $4,000/kW have been reported.[20] These costs include actual installation costs in homes in Minnesota. Within this same report, Dakota Electric observed that the round-trip energy losses for the battery system were 30%, which is much greater than projected.

[20] 2021 NRECA Battery Energy Storage Use Cases. https://www.cooperative.com/programs-services/bts/Documents/Reports/Battery-Energy-Storage-Use-Cases-January-2021.pdf.

The cost of a Tesla Powerwall is listed as $9,200 without installation and other OEM storage systems are similarly priced. Dakota Electric reviewed installation costs and observed costs in the range of $12,000 to $16,500 for a 5kW 13.5 kwhr system.[21] In this analysis, Dakota Electric assumes that the energy storage has a 4-hour capacity output. Therefore, 13.5kWhr divided by 4 results in a 3.375 kW unit. As such, taking the lower $12,000 installation cost estimate results in $3,582/kW for installed costs. Dakota Electric used an installed cost of $3,500/kW installed estimate for this analysis.[22]

The following costs assume slow growth. Option 1D is not practical for the fast growth scenario because the load growth and resulting load levels over the entire 24-hour period are too high. Since load control can only reduce loads for a maximum of 4-6 hours each day, the high loads on the remaining hours could not be controlled, making the solution not viable.

[21] https://www.energysage.com.

[22] Dakota Electric is aware that tax credits and other incentive programs may be available for behind-the-meter energy storage. Since these opportunities can be based on individual income and tax liabilities, Dakota Electric does not include these impacts in its analysis. All else being equal, to the extent tax credits or incentives exist, they will lower the cost of the battery installation.

Table 20. Option 1D - Cost Estimate for Slow Growth Scenario

Project Year	Description	Cost 2021 Dollars	Present Value @ 4% Rate
Year 1	Cost of Incentives for Members	$300,000	$300,000
Year 1	Cost of Energy Storage Systems (500kW)	$7,000,000	$7,000,000
Year 2	Cost of Energy Storage Systems (500kW)	$1,750,000	$1,666,667
Year 3	Cost of Energy Storage Systems (500kW)	$1,750,000	$1,587,302
Year 1	Cost of receiver controls (500kW)	$200,000	$200,000
Year 5	Acquire Land (3-4 acres)	$2,000,000	$1,567,052
	Permitting and Development of the Site	$400,000	$313,410
	Substation Transformer	$1,500,000	$1,175,289
	Switchgear	$850,000	$665,997
	Substation Construction / Misc Equip	$700,000	$548,468
	Transmission Interconnection	$750,000	$587,645
Year 25	Increase the Substation Capacity		
	Substation Transformer	$1,500,000	$442,954
	Switchgear	$850,000	$251,007
	Substation Construction / Misc Equip	$700,000	$206,712
	Power Supply / Monthly Demand Reduction Benefit - Operating $	-$2,323,000	-$1,698,878
	Total Cost	**$17,927,000**	**$14,813,626**

One of the major differences between this Option (1D) and Options 1B and 1C is that the load management and energy storage systems are sized closer to the actual loads as they are added to the system. Since the load management is installed at the member's home or business, the overall cost of the energy storage system is lower. However, a negative issue with this option is that Dakota Electric cannot prebuild the energy storage to ensure that there is active energy storage installed before the load level on the existing infrastructure grows above the available capacity level. This option assumes many individuals will allow the installation of energy storage in their home. This also assumes that all loads which can be controlled are controlled with the installation of a load control receiver. Any installation of residential ESS, or the application of a load control receiver, must wait for the load to be built and then convince the member to install load management or energy storage. Given these facts, there is a risk of non-supply to members.

When you compare this table with the same table in the 2021 IDP, the amount of energy storage required in Year 1 has increased. This is due to the known need for additional capacity to support the planned commercial load, which has increased the total costs of this option. More importantly, beyond additional cost, the planned commercial load renders this option unviable because there is not enough existing load to shed. Although this option is intriguing, and could represent a novel and innovative solution, it is not technically feasible.

The following are additional issues or considerations that would need to be resolved for the application of this option:

- With energy storage being installed behind-the-meter, there will be energy losses which will be recorded on the member's electrical usage. Actual energy losses have been reported to be as high as 30% with behind the meter energy storage.[23] The energy storage system would be designed to charge during off-peak hours, and the ESS could be sub-metered to support the member being charged the off-peak rate for any energy used to charge the ESS. The energy stored in the ESS would then be released during the on-peak hours and, hopefully, the rate difference is greater than the energy losses. If this process was used, there may be an additional net benefit for the member.

- The ESS could be used by the member for outage protection, which would be an additional benefit for the member, but there will need to be a control setting or system to ensure the ESS would not immediately recharge after a power outage and cause a demand on the system which is higher than the system can supply.

- If the ESS was discharged due to an evening or overnight outage, will the ESS be available to support the system during the daily peak demand the next day.

- Other cost issues arise with BTM energy storage revolving around obtaining access into the member's home to maintain energy storage systems, including potential after-hours visits.

- In time, the battery system will require replacement or refurbishment. Costs for maintenance have been included, but no costs for replacement have been included in the analysis. The assumption is the system would work to defer the construction of the substation and not be replaced when it fails. The expected life is 10 years. A significant concern is how Dakota Electric will replace or maintain these systems once their expected life is reached. It is highly likely that the members will expect these systems to be replaced, at no cost to them, if they fail or reach the end of useful life.

[23] NRECA Business Technology Report – January 2021 "The Value of Battery Energy Storage for Electric Cooperatives" Page 9.

- If Dakota Electric provided ESS systems, with energy cost reduction and outage protection for members in a small geographical portion of the system, there is a concern that other members served by the rest of the system may respond negatively to Dakota Electric spending money to install ESS and they do not have this option available.

Notwithstanding these additional concerns, it is important to reiterate that Option 1D does not work due to the known energy demands of the new commercial load. Despite this fact, Dakota Electric is intrigued by the use of dispersed energy storage and demand side management. One benefit of demand side management and ESS installed behind the meter is the ESS is dispersed among many homes and businesses, which means that a single failure of an individual ESS would not eliminate the entire ESS system. Conceptually, this is a significant resiliency gain relative to a single large substation ESS. However, a major risk, or hurdle, associated with this option is the inability to convince members to allow the installation of the ESS on their premises. Although this option is not currently viable, Dakota Electric will continue to educate itself on the topic of distributed behind-the-meter energy storage.

Moving beyond the commercial load issue, the over-arching flaw or design limitation of this option, as with option 1B, is the ESS must be able to recharge each night and be ready to reduce the next day's daily peak load. If a neighboring substation is out of service due to equipment failure, the existing circuits coming from the remaining neighboring substation would have insufficient capacity to supply the loads and also recharge the ESS.

As this option is designed, each ESS has 4 hours of capacity stored, thus the ESS would not have enough capacity to supply the load in the area for a long enough duration to support the area during a contingency like the loss of a neighboring substation. Even with these flaws, the benefits of energy storage, especially energy storage, coupled with solar, should continue to be analyzed. Dakota Electric, in concert with GRE, continues to look at ways to support the installation of behind the meter energy storage. Given the issues identified, this solution may not be able to target specific portions of the system. However, these storage options could make sense if applied across the entire Dakota Electric service territory to help reduce system peak demands. It may also be helpful for smoothing out transitions in the amount of overall power supply needs. As more solar is interconnected with the system, ESS may be able address operating issues, such as the duck curve, which occur with higher penetrations of solar interconnections.

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

Section E.2.i. 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 the greatest 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, approaches 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 400 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. Section 3. e) of this report has more discussion on the data received from the DER production meters, which show the concurrent loss of solar production and how the output from the solar DER is not coincident with the distribution peak demands. It is unfortunate that many diverse solar installations do not provide a firm electrical supply and are unable to be used to help offset distribution facilities.

f) Timeline Required to Consider Non-Traditional Solution Alternatives

Section E.2.ii. 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. As noted in Appendix A, question #28, 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 ESS systems, has 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.iii. 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.iv. 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.

5) 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 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.

Dakota Electric regularly reviews its planning assumptions and conducts long-range engineering analyses and forecasts. This long-range planning forms the foundation of our expectations for the equipment necessary to serve new and existing loads over the five-year planning period. This engineering analysis synthesizes real world system data along with load growth expectations to create an expected engineering plant budget.

These planning assumptions and decisions have also been complicated recently by supply chain issues. As discussed earlier in this IDP Report, these supply chain issues have resulted in significant increases in cost and increases in equipment lead time. These compounding factors have created planning challenges that we have addressed and continue to address. Dakota Electric, like any distribution utility, has an obligation to serve its end users and provide new or expanded electrical service in a timely and cost-effective manner. The supply chain issues Dakota Electric, and the industry as a whole, has experienced (and continues to experience) since the last IDP Report are significant. Dakota Electric has been able to plan effectively and is well positioned to meet the growth needs of our membership. To date, we have been able to meet these challenges, but the need to address these significant operational and supply chain complications has required us to move some emphasis away from medium and long-range planning toward present operational considerations. Dakota Electric remains committed to thoughtful long-range planning that maintains the efficient operation and growth of our system despite the present headwinds that the industry is experiencing.

<u>AGi Project</u> – The AGi Project represents the largest single project in Dakota Electric's history and will help shape many facets of our distribution operation and planning for decades. By early 2024, Dakota Electric expects that the installation phase of the project (which includes meters and load control receivers) will be substantially complete. With all meters and load control receives installed, Dakota Electric will be able to fully enter the next phase of the project, which is leveraging and using the detailed system data provided by the meters to improve operations and increase value to the membership. Despite remaining in the deployment phase of the project since the filing of the last IDP Report, Dakota Electric has already derived significant value from the functionality of this equipment through improved meter reading performance, reduced member cost (reconnection fee reduction, Docket No. E111/M-22-494), and new program development (Virtual Metered EV tariff, Docket No. E111/M-22-592). Receiving the full benefits of the AGi project is a major objective for Dakota Electric, and we are excited to transition from the deployment to operational phase of the project, especially in light of the significant improvements we have already realized. The AGi system consists of 15-minute internal data and, in the future, there will be value in allowing members to view and access the data if they so desire. These members will be able to use the data to make data driven decisions about their energy use which could impact future distribution planning, especially if these members significantly shift or modify their energy usage patterns. Dakota Electric will continue to develop ways to use the data provided by the meters and load control receivers to help our membership by improving the quality of their service.

The AGi project supports the following Commission objectives and furtherance of overall grid modernization:

- Improved safety and reliability through the ability of each of the meters to report events, such as high temp in the meter socket or LAST GASP outage notifications. This functionality has already derived significant value for Dakota Electric through pre-emptive identification of safety and power quality issues. As we complete full deployment and receive additional experience with this technology, Dakota Electric anticipates further process and safety improvements;
- Greater customer engagement and empowerment through providing the 15-minute interval usage data to the members that will allow them to better understand how they are utilizing electrical energy. This ability to access data is an important part of various operational and technological improvements that Dakota Electric is currently considering and reviewing as part of greater strategic focus at the organization;
- Support additional options for energy services through better understanding of how different classes of members are using energy;
- Provides an accessible grid platform to help us develop new products (rates) and new services and adoption of new technologies. Dakota Electric's recently approved pilot virtual metered EV rate and lower reconnection and service fees are early examples of the products and improvements made possible by the AGi Project. We anticipate further program development over the next 5 to 10 years; and
- Improved efficiencies, optimization, and utilization of the electric grid access to minimize total system costs through information provided from the meters and load control devices. The load control devices will alert Dakota Electric to non-functioning devices which are not able to control the loads as intended. The meters will alert us when they malfunction and need to be replaced. In addition, the new AGi system is also allowing us to identify and repair load control receivers which are not operating as expected. This could be due to many issues such as failed equipment, electrical wiring changes initiated by the member, or replacement of the equipment being controlled.

Operational Technology and Cyber Security – 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 apparatus. While these are not physical components of distribution planning, or a field capital 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. Dakota Electric's ERP and work order systems have recently been replaced, and we recently began the process of upgrading our GIS, outage management system (OMS), and SCADA systems. These are complex, inter-related systems that also include sub systems and supporting 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. The process of updating these systems will also allow Dakota Electric to explore and potentially install advanced functionality through an ADMS platform.

Energy Storage – Energy storage utilization supports the Commission's IDP planning objectives in the following ways:

- Additional options for energy services and empowers the membership to utilize a new technology;
- Helps optimize the utilization of grid access through the management of distribution peak demands; and
- Enhances the reliability, security, and resilience of the energy supply for our membership through back up power supply options.

Over the past several years, Dakota Electric has investigated the possibility of utilizing a utility scale energy storage system to support the interconnection of additional DER to one of our transmission limited substations. The project included an analysis and review of the physical and economic possibility of installing an energy storage system at a substation where the transmission system protective relaying could not support back feeding of the transmission. If a substation is limited from back feeding, and Dakota Electric is unable to do anything, Dakota Electric may need to tell our membership that they cannot add any more DER to specific substations. The conventional, physical fix to allow transmission back feeding requires the construction of a transmission switching substation, which would likely cost several million dollars. An alternative solution that was under consideration was for Dakota Electric to consider installation of a utility operated energy storage system. Conceptually, the energy storage would charge the batteries when the DER on the impacted substation is generating sufficient energy to potentially back feed the transmission system. The BESS would then discharge in the evening and at night when the DER is not generating excess energy.

Dakota Electric began the initial review of this concept in its 2021 IDP but did not develop an economic analysis detailing the cost/benefits of this potential solution. We did not conduct a more detailed analysis because the initial information suggested that the cost of this solution would be unreasonably high and not economic in all situations. The other issue we encountered was that the significant amount of utility scale energy storage projects limited the availability of vendors willing to bid on smaller projects such as what was required for Dakota Electric. Finally, there were factors with our wholesale power supplier GRE that impacted the overall economic viability and functionality of Dakota Electric's conceptual project.

Dakota Electric continually monitors the market and economics for energy storage and notes that there have been significant changes related to energy storage (and electrical distribution in general) since we filed our last IDP. Although Dakota Electric remains interested in utility scale energy storage solutions, as noted earlier in this section, supply chain related circumstances required us to devote significant resources to ensuring we have sufficient distribution resources on hand to meet the needs of current and future members. Further, continued evolution in battery technology, pending changes in certain wholesale power provision (discussed below), and recent changes in legislation related to the IIJA and IRA will significantly impact the potential viability or planning process for energy storage solutions. Dakota Electric is incorporating these changes into its analysis of future storage projects.

In addition to utility scale energy storage solutions, Dakota Electric is closely following BTM energy storage and how this may impact the distribution system. Currently, we only have a handful of these storage facilities on our system but, based on growth in places such as California, Dakota Electric expects that these will become more popular with our membership. Dakota Electric sees these resources as an opportunity to improve DER integration and management on our system, and we are investigating member-focused solutions that will help us gain a better understanding of how BTM storage can benefit individual members and the cooperative as a whole. This is an area where we anticipate further innovation during the next 5 to 10 years.

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. In fact, during preparation of this report, Dakota Electric has seen a noticeable uptick in the number of EVs being added to our rate programs, which suggests that the number of vehicles entering the Minnesota market is increasing rapidly.

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. Although an EV load on its own is not significantly different than other larger household loads, if they occur 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 forward. In addition, as the energy transition continues, it may be appropriate to have program options that are more adaptable and dynamic. This is why Dakota Electric is beginning the process of examining other program delivery options.

Public charging is another component of electric vehicles that has garnered additional attention since we filed our last IDP. The issue of public charging and range concerns have always been present with electric vehicles, but it has taken on greater significance as EV adoption increases and the recent allocation of Federal funds through the NEVI. In support of the State of Minnesota's NEVI application, Dakota Electric reviewed its system and mapped all locations along the I-35 corridor in our service territory that would be able to support DCFC. Over the 5-year planning horizon, Dakota Electric will continue to proactively monitor and plan its system so that it can respond to public charging requests and connect these in a cost effective and equitable manner. Further, as public fast charging becomes more prevalent, we also anticipate reviewing rate options and system use to ensure that system costs and benefits are optimized.

Although not specifically included in our EV planning assumptions, it is also important to note the opportunity and risk of large fleet charging. It is difficult to project these impacts because there are no widespread installations in the market and each use case is different. For example, if you have a delivery fleet that only operates during the day, it is likely that overnight charging options will work; however, if a company operates a 24/7 fleet, then a different solution and resulting system impacts will exist. Generally speaking, fleet charging will mimic "regular" large load additions, but they may also introduce unique system challenges and dynamics based on the fleet operations. Dakota Electric is continually researching this field and has been working with perspective members about potential solutions and planning objectives when this occurs.

Continued promotion of EVs will support the Commission's objectives in the following ways:

- Increase options and accessibility for members to utilize EV rates and help provide cost effective options for charging Electric Vehicles;
- Provide increased support for new services and adoption of new technologies; and
- Transition additional members to EV TOU and/or off-peak rates that will help optimize the utilization of electrical grid assets and resources through the management of peak demands.

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 which the Community has 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 will be the fourth utility scale solar generator in the Dakota Electric service territory and will be an important part of the Community's plans to meet their net zero objectives. The expectation is that the facility will become operational in early 2024. 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 plans and to work through any issues which may occur. To the extent significant changes or developments occur regarding this initiative during the 2023 IDP proceeding, Dakota Electric will update the Commission. Dakota Electric has also expressed our willingness to work with and aid the Community with any Federal grants and programs they may undertake as part of the IIJA or IRA.

Support for the Prairie Island Communities Net Zero Initiative, and other energy goals, will also meet the Commission's objectives in the following ways:

- Provide greater member engagement for the Community through empowerment of member choice and support of options for energy service; and
- Ensure efficient optimized utilization of the electrical grid, through partnering with the Community to ensure the coordination of the design and installation of the renewable energy systems and the resulting reliable operation of the facilities.

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 is slated to begin in 2025 and is expected to take over 10 years to complete. The current budget for this project is approximately \$2-\$3 million a year; as such, this will represent a significant long-term, and ongoing, capital expense for Dakota Electric. We believe these expenses are reasonable because they will modernize or system and improve overall resiliency. Furthermore, they will also meet the Commission's IDP objectives in the following ways:

- Enhance the reliability, security, and resilience of the distribution system through replacement of aging, less reliable equipment with newer equipment;
- Improve employee safety though replacement of older equipment with newer equipment which has improved operational safety improvement; and
- Improve efficiency of the distribution system with the installation of more efficient equipment.

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 in 2023, this transformation will need to continue over the next 5 to 10 years ao 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 our load using renewable resources. This component also governs other aspects and requirements of certain self-generated projects. Dakota Electric currently has three solar facilities that operate under this agreement with Great River Energy and, as noted earlier in this section, we expect a fourth facility to come online in late 2023. Great River Energy and its members recently approved an expansion of this program and changes to requirements associated with self-generator. 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. These wholesale power provisions meet the Commission's IDP planning objectives by:

- Replacing fossil fuel generation with renewable resources; and
- Supporting additional options for energy services and demand response programming.

6) BASELINE DISTRIBUTION SYSTEM AND FINANCIAL INFORMATION

The following section is in response to the request for information contained in the original IDP order, Docket E111/CI-18-255 (the 2019 Order), Section A, request to provide "Baseline Distribution System and Financial Data." Dakota Electric discusses this information separately below.

a) System Data: Modeling Software

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

Dakota Electric continues to use the 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.

b) System Data: SCADA Penetration

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

100% of Dakota Electric's 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 the 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 is 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. Based on a literature review and discussions with the DER vendors, Dakota Electric's ability to curtail these large DER systems appears unique in the industry. 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 continencies. This arrangement is mutually beneficial, as it provides Dakota Electric with operational flexibility and DER generators with economic benefits.

As a benefit of the AGi project, and our production meter requirement, Dakota Electric can 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 truck rolls. All of these responses, or interventions, can be remotely accomplished without interrupting electrical supply to the 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 the 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.[24] 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 nearly complete. By early 2024, all meters will be substantially exchanged for AMI meters, except for the few members (around 165) 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 was reported in the 2021 IDP for Dakota Electric. In addition to sending back alarms or notification for events, 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.

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

1) kWhr (Delivered);
2) kWhr (Received);

[24] iHistorian is the Dakota Electric software system which stores and supports retrieval of the data collected by the SCADA system.

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) kWhr (Delivered);
2) kWhr (Received);
3) kVARhr (Lagging);
4) kVARhr (Leading);
5) kVAhr (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;
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) kWhr (Delivered);
2) kWhr (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.

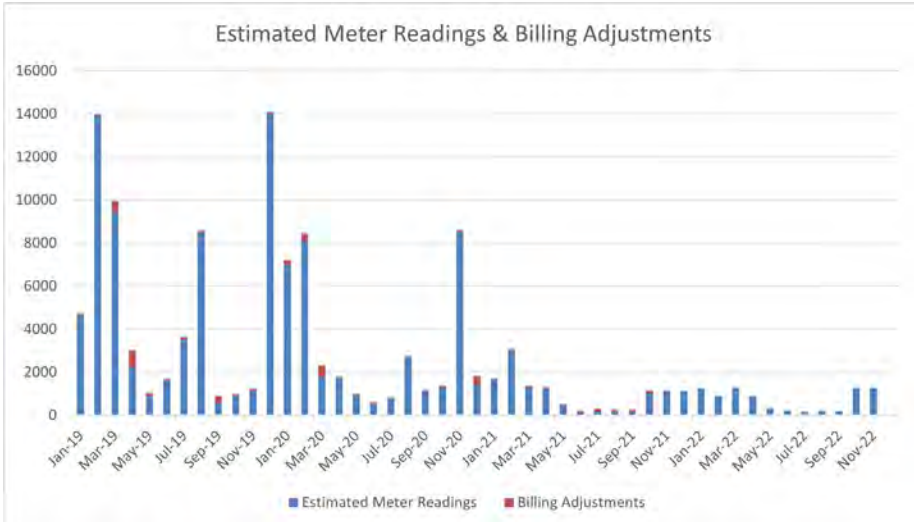
Since the 2021 IDP report was filed, Dakota Electric is now using the internal switch within many of the single-phase residential meters to disconnect and reconnect the member's electrical service. The internal meter switch allows Dakota Electric to remotely turn off the flow of energy through the meter. 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 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.[25] This reduction in travel and labor expenses also saves the member through lower reconnection fees.[26]

At the time this report was prepared, just over 165 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 are not providing interval data into the meter data management 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 very limited information available for engineering models and engineering analysis.

The AGi system has benefited the membership in several ways. The first is directly through improved accuracy with the monthly billing. In the following graph, you can see how prior to the installation of the advanced meters, the amount of estimated bills and billing adjustments was higher than after the use of the 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 shows 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.

[25] Docket No. E111/M-22-494.
[26] Docket No. E111/M-22-227.

Graph 17. Estimated Meter & Billing Adjustments Before and After AGi Meters Installed



The final benefit to members is the indirect benefit of reduced internal labor being required to estimate billing and resolve billing 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 GRE'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 electrical systems. 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 is supplying 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-wired alternatives (NWA). As the electrical grid continues to evolve to meet consumer's 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 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 Dakota Electric's 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. We continue to work with GRE on this issue, but there have been difficulties because GRE does not own or operate much of the transmission system that Dakota Electric's substations are interconnected to. Dakota Electric is concerned that absent improvements to the transmission interconnection process, and supply chain environment, this will 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.[27] In addition to these efforts, GRE provides support and coordination for many different energy 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

[27] Prior to the early 2000's, 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.

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 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 DER is 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 projects out 15-20 years. 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 DER penetration and generation levels are embedded in the historical monthly and annual energy usage by member category for the forecast. The issue in this case is that these historical growth patterns may not be representative of future DER penetration levels. 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. This forecast was used in the GRE IRP.

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 our 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, so new DER additions are not able to be included in the annual feeder and substation load 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 (which are the DER installations on the Dakota Electric service territory) are intermittent and there are many hours during the year when the DER systems do not produce energy or are operating 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. There could also be a worst-case scenario where an overload could occur and damage equipment and/or low voltage to member homes and business which also could damage member equipment.

<u>Cold Load Pickup</u> - 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 in the 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), and 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 is currently required to follow the same reconnection (enter service) requirements.

As noted earlier in this section, 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. Dakota Electric is reviewing its rates and time windows for Time-of-Use (TOU) rates to see where adjustments are needed.

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, it is critical to know the maximum total load behind each meter and thus the potential magnitude of load which could be placed upon each of the circuits, to ensure enough feeder capacity during cold load pick-up events. Using the AGi meters, with 15-minute interval data, this can be identified 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 will be changing 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).

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 for these systems to help reduce low voltages within the home will become a possibility.

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.

Table 21. 2022 Distribution System Losses

2022 - Months	Monthly System Loss Percentage
January	2.81%
February	2.99%
March	3.29%
April	3.15%
May	3.32%
June	3.59%
July	3.24%
August	3.31%
September	3.11%
October	3.12%
November	2.38%
December	2.32%

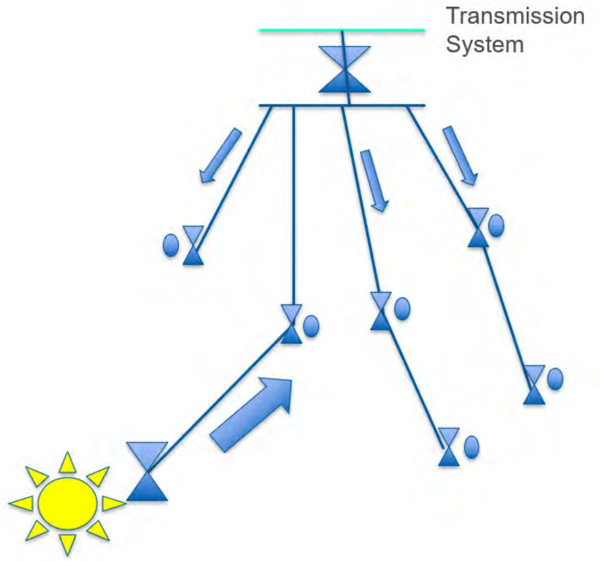
In the table above, the loss values vary by month due to many factors and these factors can be highly interactive, and the monthly losses are the result of the 24 hour a day 7 days a week interaction of the factors. Below is a table of some of the key factors which impact distribution losses.

Table 22. Variables Affecting Energy Losses on a Distribution System

Equipment	Factor	Affect
Wires & Cables	Amps (energy flow)	The losses increase by the square of the current. Double the current is 4 times the losses.
Wires & Cables	Voltage	Higher voltage reduces the current level to deliver the same energy – so this lowers the losses. We operate the system voltage higher during the day to reduce these losses.
Transformers	Voltage	Transformers use energy to keep energized. The lower the voltage, lower No-load losses. We lower the distribution operating voltage each night to reduce these transformer no-load losses
Distribution System	Contingency or Maintenance outages of equipment	When equipment is taken out of service the energy is rerouted to flow over neighboring equipment. This increases the flow on the other equipment and increases the distance the energy must flow, increasing losses

The AGi project included the installation of meters which are remotely read and support daily meter readings; this is one of the significant benefits of the AGi project. From this data, meter readings which coincide with GRE's monthly meter readings can now be used for the purpose of calculating distribution losses.

Figure 16. Distribution One-line with Interconnected Utility Scale Solar



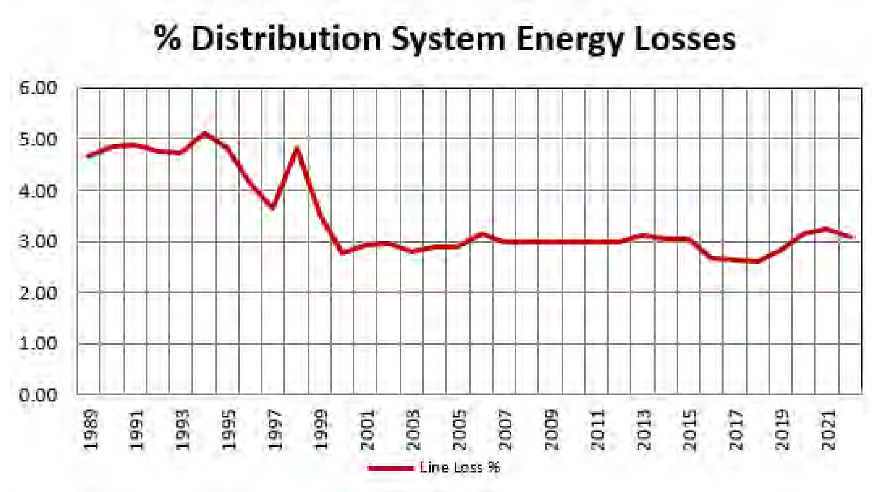
Adding solar to the distribution system, especially larger utility scale solar can result in greater distribution system energy losses due to the amount of distribution wires and transformers which the solar energy must travel through. The path from the substation to the loads is the normal path for the energy flow, but the additional factor is the large amount of energy flowing from the solar system up the single circuit to the substation. Some of the loads along this path absorb the energy from the solar generator, but the majority flows to the substation and is then distributed. In addition, since this is a higher level of current on the feeder wires, and we know that losses increase with the square of the current level, the losses on this one circuit are significantly higher compared to normal losses.

The figure above shows the transformers through which the energy must flow. Overall, transformer energy losses result in 40-50% of the losses on Dakota Electric's distribution system. The energy flowing from the solar system must first pass through a step-up transformer to get the energy to the distribution voltage and then it will pass through a transformer at each of the services where the energy is consumed. This configuration is doubling the distribution transformer losses.

It is important to note that the substation transformer and transmission losses may decrease as solar energy reduces the flow over these components. However, in the case of Dakota Electric, we do not realize these gains because we receive all energy on the distribution side of the substation transformer. Overall, the amount of energy loss reductions on the transmission side is expected to be less than the increase in the overall distribution losses due to the higher operating voltages of the transmission system that results in increased efficiencies.

Historical Distribution System Losses: The graphs below show Dakota Electric annual system losses and suggest a potential new trend of increasing distribution system losses over the past few years.

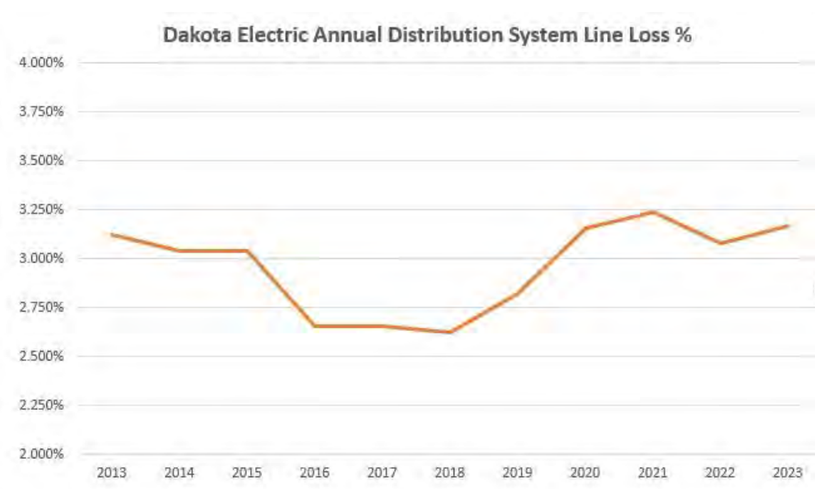
Graph 18. Historical Distribution System % Energy Losses



Despite the increase in system energy losses the past few years, as shown in the graph above, Dakota Electric distribution system energy losses over the past 30 years have improved significantly. This was accomplished through various changes including: purchasing more efficient equipment (such as distribution transformers), changes in how the system voltage is managed during light loading periods, addition of improved control systems for distribution capacitors, and replacement of existing distribution system components (such as wires and cables with larger capacity).

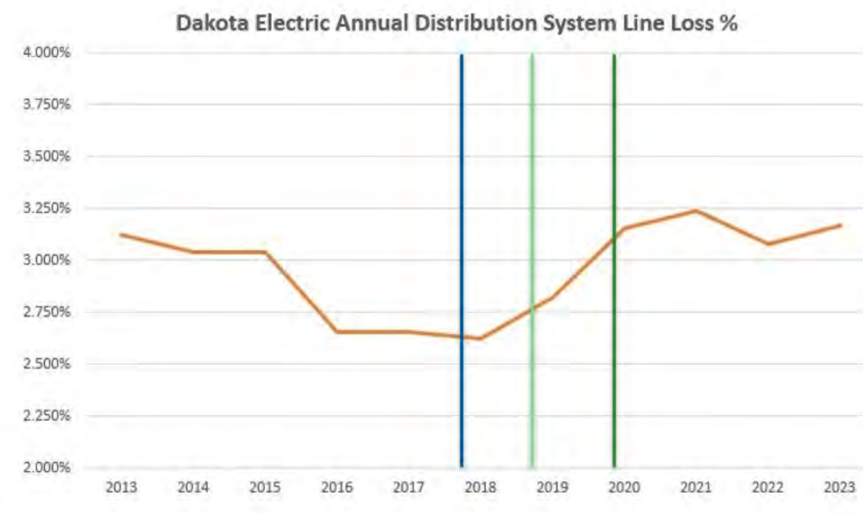
The graph below provides a closer examination of the most recent years of line loss data which shows a change in the trend of reduced energy losses. Starting with 2018, the distribution system losses have been increasing. It will be interesting to monitor system losses in the future, as the recent annual energy loss percentages are still near the nominal 3% level that has existed for the past 10 years.

Graph 19. Distribution % Energy Losses (2013-2022)



When this topic is examined in greater detail, the increases in system losses roughly correspond with the interconnection of larger utility scale solar and increased member owned solar systems. Dakota Electric believes most of the increased energy losses are due to the operation of the larger multi-megawatt solar systems, which are not associated with load, and sell all their energy to the utility. Below is the same figure but with lines showing when each of the multi-megawatt solar systems started commercial operation. Each of the solar system additions correlates with an increase in distribution systems losses in the following year.

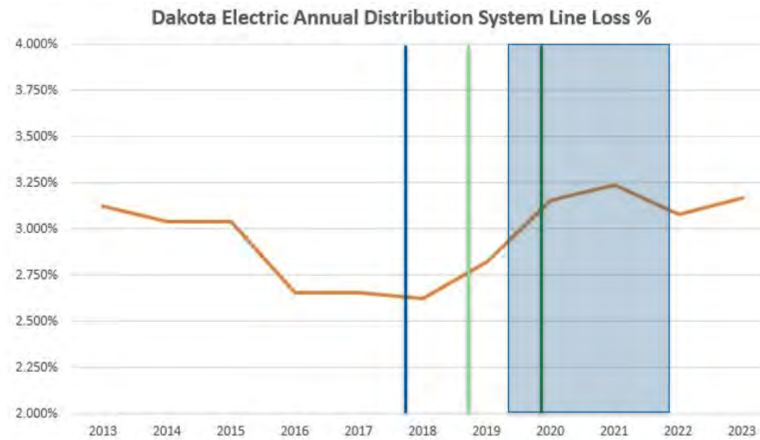
Figure 17. Distribution System Losses correlated with Large Solar System Additions



The increase in system losses due to the interconnection and operation of solar systems is believed to be the result of the energy from the solar system traveling across more of the distribution system compared to energy which is received into the substation directly from the transmission system. Figure 16 above is a basic one line showing the flow of energy from the solar DER, up the feeder to the substation, and then back down the other feeders to the loads.

The mitigation in the slope of the increased losses in 2021, and the reduction in losses in 2022, are likely attributed to the installation of the new AGi meters. The mass replacement of old meters with the new AGi meters started in July of 2020 and was completed by January 2022. These are represented in the shaded area in the following figure.

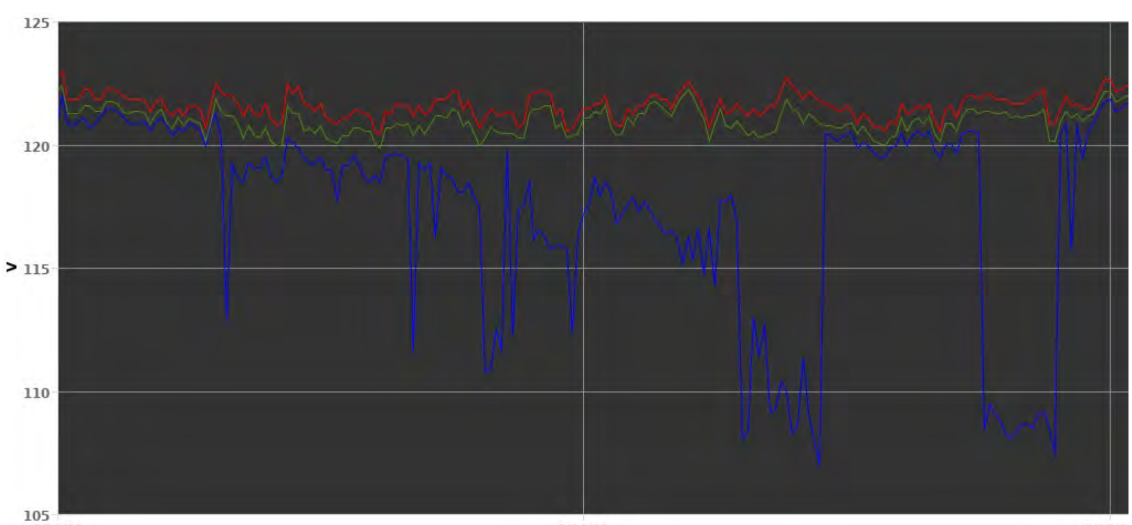
Figure 18. Distribution System Losses correlated with AGi Meter installations.



The replacement of older analog meters with more accurate digital meters resulted in more accurate metering of the flow of energy, especially during periods of low usage. As part of the metering replacement, and the ability of the new AGi meters to report on the input voltage and current inputs into the meter, Dakota Electric was able to identify some locations which were metered using incorrect types of metering, which resulted in less energy being metered then was consumed. Further, the new AGi system was able to alert us if the voltage being supplied to the meter was outside of normal levels, either high or low and was incorrectly reporting voltages to the meter.

The graphs below shows three phase voltages being reported by a multi-phase meter. This graph shows that one phase voltage is not accurately metered, and, as a result, the energy consumed by the premise is greater than what is being recorded by the meter. For many multi-phase meters, there are potential transformers which convert the service's higher voltage (277-480V) to a lower 120 Volts which can safely be metered. In this case, the connections from the potential transformer (PT) to the meter were not solid. Correcting these metering issues reduces overall distribution system losses because the energy is registered as sold energy and not lost.

Graph 20. Voltage Graph of Meter – Incorrect Input Voltage to Meter.



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 of the Dakota Electric distribution system at the time of peak system demand for Dakota Electric (1) and at the time of peak system demand for GRE (2). 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.

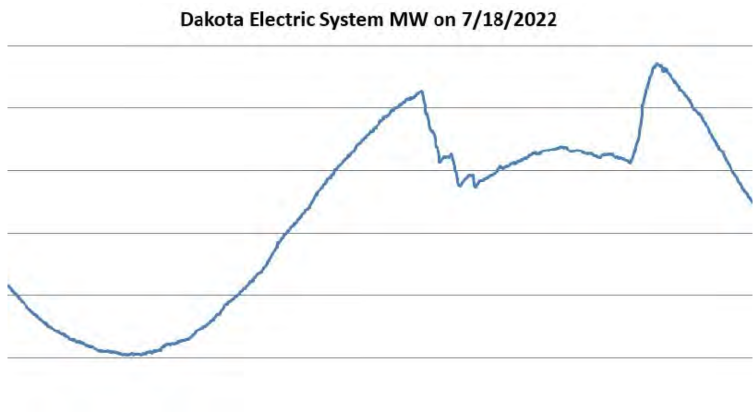
Table 23. Historical System Peak Demand (3)

Year	(1) System Peak Demand (MW)	(2) Peak MW demand with Load Management Active
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 YTD	473	455

(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) Both of the demand values are reduced by any coincident DER generation amounts and do not reflect the maximum electrical load in the area.

The figure below is the load shape for a typical summer peak day with load control in 2022. The reduction in electrical demand from operation of load control is significant and clear. The demand, at the end of a load control period, which is higher than other periods of time during that day, is referred to as a “rebound peak.” If the end of the control period is not properly coordinated, the rebound peaks can cause system overloads and/or low voltage. As such, overall coordination of load control is important to help limit the size of “rebound peaks” and avoid potential reliability issues, or shifts in billing peaks, in the immediate period after control.

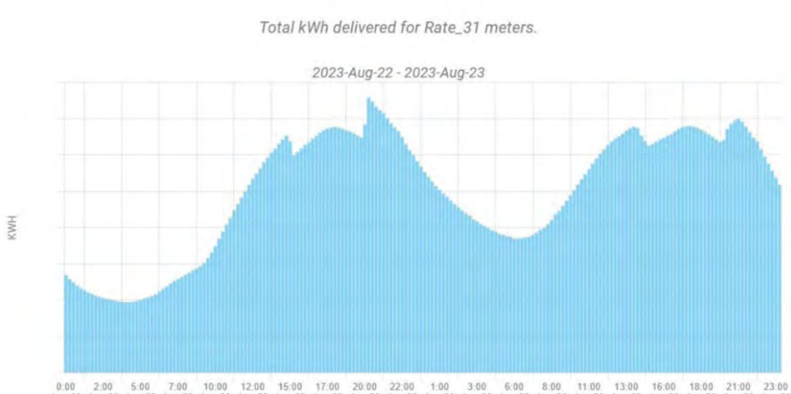
Figure 19. Summer Peak Day with Load Management



The figure above highlights the success of Dakota Electric’s demand-side management and load control programs and how they effectively decrease peak demand on our system. This decrease in peak demand saves our members significant money through avoided capacity costs with GRE. The above figure shows the total system load, commerical and residential, and the ability to reduce the electrical demand on our system using all of the different load control systems.

The graph below shows the usage from just residential users. The consecutive peak days allowed us to compare different methods of implementing load control. On the first day, all residential control was started and stopped at the same time. For the second day, the control was filtered on and off, and this change in strategy resulted in little if any rebound peak demand. Individual homes were controlled for the same amount of time on both days.

Graph 21. Residential Member Usage on Two Consecutive Peak Days



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 of that year. Notice that Dakota Electric has not needed to add additional substation capacity for the prior 3 years.

Table 24. Historical Total Distribution Substation Capacity

Year	Total Distribution Substation Capacity (kVA)
2019	1,135,200
2020	1,158,100
2021	1,172,500
2022	1,172,500
2023	1,172,500

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 25. Total Distribution Transformer Capacity

Year	Number of Transformers	Total Transformer Rated kVA
2018	23,271	1,055,552
2019	23,278	1,057,624
2020	23,420	1,059,892
2021	23,725	1,087,151
2022	23,940	1,102,132
2023	24,202	1,119,718

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.[28] The amount of overhead line continues to decrease as urban areas expand and the existing wires are replaced by underground cables.

Table 26. Miles of Overhead Line

Year	Miles of Overhead Lines
2018	1,188
2019	1,182
2020	1,177
2021	1,175
2022	1,161

[28] For example, three-phase line includes four strung conductors. A three-phase line that extends for one mile has four miles of wire footage.

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 miles of underground cables continue to increase as new developments are added to the system.

Table 27. Miles of Underground Cable

Year	Miles of Underground Cables
2018	2,961
2019	3,003
2020	3,041
2021	3,098
2022	3,132

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 28. Total Number of Services (Distribution Customers)

Year	Number of Member's (Services)
2018	108,274
2019	109,089
2020	111,007
2021	113,011
2022	114,775

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 2018-2022, the following are the direct labor and material expenses incurred in support of the interconnection and installation of DER generation.

Table 29. Cost Incurred from Interconnection & Installation of DER Generation

Category	2018 Expenses	2019 Expenses	2020 Expenses	2021 Expenses	2022 Expenses
Application Review	$57,437	$71,395	$105,228	$116,608	$91,445
Responding to Inquiries		$14,351	$17,568	$18,751	$15,318
Make Ready		$1,732	$2,071	$25,868	$43,515
Testing		$23,912	$21,199	$24,782	$25,349
Total Costs (1)	**$57,437**	**$111,390**	**$146,066**	**$186,009**	**$175,627**

(1) Total costs do not include the cost of the production meter which is provided by Dakota Electric at no additional cost to the member.

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 category in which they were incurred (including application, fees, metering, make ready, etc.).

For the calendar years 2018-2022, 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 30. Total Charges to Members for DER Generation

Category	$ Paid				
	2018	**2019**	**2020**	**2021**	**2022**
Application Fees	$4,700	$10,946 (1)	$23,054	$48,050	$37,832
Metering	$0	$0	$0	$0	$0
Testing	$0	$0	$0	$0	$0
Make Ready (2)	$0	$872	$870	$7,417	$15,348
Total	**$4,700**	**$11,818**	**$23,924**	**$55,467**	**$53,180**

(1) 2019 Application fees is calculated from the number of applications in the 2019 Commission DER report since the NOVA on-line portal was not fully functional during the entire year.

(2) 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.

i) DER Average Cost Per Application

Using the costs and charges from the answers to above IDP Section A questions 15 and 16, and utilizing the number of units interconnected from question 19, Dakota Electric calculated the average costs for handling DER applications.

Please note, the average cost to support each DER interconnection has been greatly reduced by Dakota Electric through several internal process improvements. These changes include the implementation of the AGi advanced metering project, which eliminated the need to replace the main meter with a more expensive bi-directional meter; modifying several internal processes to reduce the labor required to review applications; and implementing the use of iPADs by the field technicians to facilitate access to information by the field crews and inhouse engineering. The use of electronic files speeds up the review process and reduces the cost and labor involved with printing out one-lines and other data to be used by the field crews. The implementation of the NOVA DER application portal (2019) has also helped streamline internal processes and process tracking. The NOVA portal also helped improve the process for DER installers and their interactions with Dakota Electric.

Table 31. Average Costs for DER integration

Category	2018	2019	2020	2021	2022
# of Interconnections per year	40	98	138	371	322
Total DEA Costs	$57,437	$111,390	$146,066	$186,009	$175,627
Average DEA cost per DER	$1,436	$1,137	$1,058	$501	$545
Total Receipts	$4,700	$11,818	$23,924	$55,467	$53,180
Average Receipt per DER	$118	$121	$173	$155	$140
NET Total Cost to Dakota Electric	$52,734	$99,572	$122,142	$130,542	$122,447
Net Dakota Electric's Cost Per DER Interconnection	$1,318	$1,016	$885	$352	$380

q) System 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 2018-2022, the following are the aggregate nameplate capacity of the different DER generation systems that completed interconnected to Dakota Electric's distribution system.

Table 32. Total Nameplate Capacity of DER Generation Interconnected by year

Year	Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
2018 (1)	2,406 kW	0	0	0	500 kW	0
2019 (1)	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

Note (1): 2018 includes a single 2,000 kW solar installation and 2019 includes a single 3,000 kW solar installation.
Note (2): Solar/Storage column refers to DC coupled ESS 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 2018-2022, the following are the total number of DER generation systems, by type, that completed the interconnection process with Dakota Electric's distribution system.

Table 33. Number of DER Generation Systems Interconnected by year

Year	Solar	Solar/Storage (1)	Storage	Wind	Gas Engine	CHP
2018	39	0	0	0	1	0
2019	97	0	1	0	0	0
2020	137	1	0	0	1	0
2021	366	1	4	0	1	0
2022	312	0	9	1	0	0

Note (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 September 2023 and the total nameplate capacity of those units.

Table 34. Total Number of DER Generation Systems Interconnected

	Solar	Storage (2)	Wind	Gas Engine	CHP
Number of	1,325	24	10	126	0
Total Capacity kW	17,360	148	154	84,191 (1)	0

Note (1) Engine Prime Rating
Note (2) All of the current storage projects are at existing solar installations.

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 35. Number of DER Generation Systems in Interconnection Queue

Solar	Solar/Storage	Storage	Wind	Gas Engine	Hydro	CHP
86	1	4	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.[29] On May 30, 2023, 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 May 1, 2023, members have enrolled 1,033 plug-in electrical vehicles on Dakota Electric's EV charging rates.

Dakota Electric believes that around 45% of its members with EVs have them on one of our EV rates. Assuming 45% of EVs are on an EV rate, that would suggest approximately 2,296 EVs on the Dakota Electric system. This is similar to the January 2023 EV numbers reported by PUC where they estimated 2,046 EVs on the Dakota Electric system. In the first few months of 2023, Dakota Electric has experienced increased growth in the number of members signing up for EV rates. As of July 2023, we now estimate 2,500-2,600 EVs in the Dakota Electric service territory. This would represent an increase of approximately 200 to 300 vehicles in less than six months.

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 Dakota Electric filed this IDP Report, it 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 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

[29] 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 additional to Dakota Electric's TOU EV charging rate and EV charging that is available through our interruptible storage off-peak program.

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 recharging 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 September 2023, Dakota Electric has 24 energy storage systems which are interconnected with the distribution system. There are 5 systems which are in review or approved. Each of these systems are coupled with solar installations and are either DC or AC coupled. All the energy storage systems are coupled with the solar and most will allow the solar to continue generating during an outage and prolong the benefits of the backup system.

The smallest ESS system is rated at 1.28kW (3.36 kWhr) and the largest is rated at 15 kW (29.1 kWhr). Total capacity for all interconnected and applied for interconnection systems is 203 kW (526 kwhr).

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 18,907 MWh of savings in 2022.

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 A.31 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 A.31.

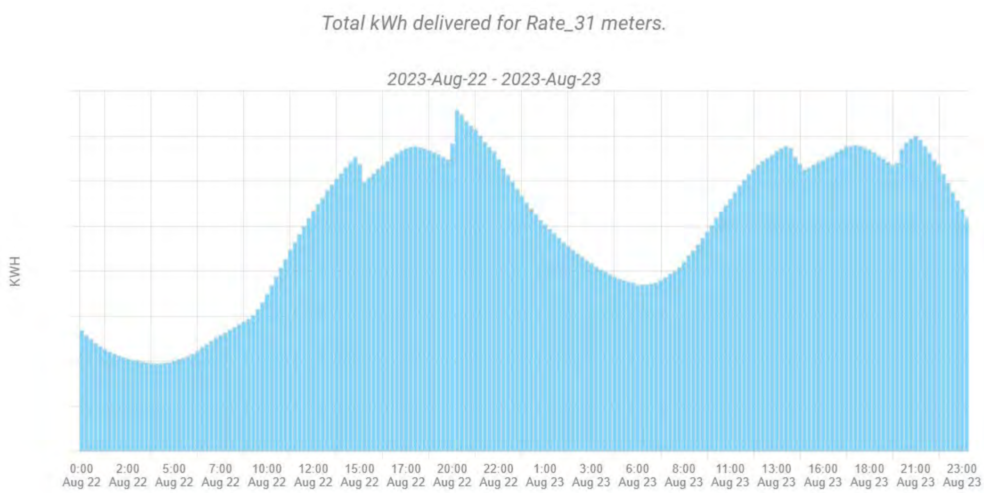
The actual amount realized when the "control button is pushed" is different (lower) than the sum of the connected kW values. For each type of load, there are different factors impacting the actual amount of realized load reduction when the control button is pushed.

<u>Air Conditioning</u>
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. For example, during a 90F-day in May, most of the AC units in our service territory are not operating and the resulting load reduction due to control is less. However, for a 90F day in June, July, or August, most of the AC units in our service territory are operating, and we can see a greater reduction in

load during control 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 turning down 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 efficient units. It is important to note that there is an implicit overall reduction in electrical demand from these more efficient 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 22. 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

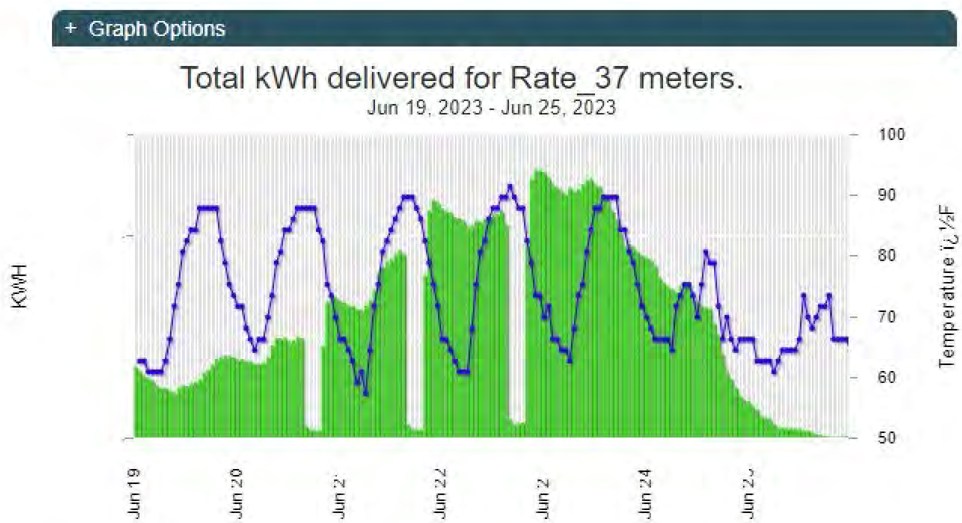
Heating devices can include methods such as in-floor heating, electric strip heaters, or infrared heating. The use of these devices is variable as the heating device can be the main heat for a residence or supplemental heating for a room or garage. The expected load reduction is between 5-10 MW due to 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 23. 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 36. Load Reduction Estimated by Program Type

Program	Number of Units	MW Connected	MW Reduction Summer	MW Reduction Winter
Air Conditioning	52,189	153	10-20	N/A
Heat Pump	2,765	10	3-5	2-8
Heat Device	3,331	29	N/A	5-10
Irrigation	377	24	0-12	N/A
Miscellaneous	738	4.7	1	1
Water Heat	7,372	33	4-8	5-10
C&I Interruptible Generation	127	85	50-65	30-50
Curtailment	20	9	2-5	2-5

Note: 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 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: Historical Distribution System Spending

Section A.26. Historical distribution system spending for the past 5-years, in each category:

- *a. Age-Related Replacements and Asset Renewal*
- *b. System Expansion or Upgrades for Capacity*
- *c. System Expansion or Upgrades for Reliability and Power Quality*
- *d. New Customer Projects and New Revenue*
- *e. Grid Modernization and Pilot Projects*
- *f. Government Mandates Projects related to local (or other) government-requirements (i.e. road-relocations)*
- *g. Metering*
- *h. Other*

The table below shows Dakota Electric's capital spending for construction over a historical 5-year period (2018-2022) by various 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 in these construction capital projects.

As previously explained in the 2019 and 2021 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.

The table below is an engineering estimate of the breakdown for the requested categories using the actual total capital spending over the most recent 5 years.

Table 37. Historical Total Capital Spending

	2018	**2019**	**2020**	**2021**	**2022**
Age Related Replacement	$4,195	$3,066	$5,771	$2,426	$3,108
System Expansion (Due to Capacity)	$716	$831	$694	$3,263	$2,772
System Expansion (Due to Reliability)	$1,220	$1,308	$1,025	$1,176	$1,225
New Members	$3,006	$4,302	$4,099	$4,561	$5,782
System Project (Driven by Mandate)	$1,263	$1,306	$1,107	$1,532	$1,659
Metering	$0	$103	$5,592	$12,381	$0
Grid Modernization (Advanced Technologies)	$361	$1,057	$2,685	$3,348	$3,950
Annual Total	**$10,762**	**$11,973**	**$20,972**	**$28,687**	**$18,495**

Note: All dollars are in Thousands

Dakota Electric notes that the estimated allocation of these costs to the various categories is difficult and results in a rough estimate of costs. It is important to stress that the coding system, which Dakota

Electric uses for budgeting and tracking capital construction, tracks what was constructed, rather than why it was constructed. Converting what was constructed, especially for historical construction projects, into categories which are based upon why each project was constructed, is a subjective process. In the interest of transparency, Dakota Electric provides notes and discussion below about how it decided to assign spending from the tracking code categories into the various construction categories.

For some of the activities which are tracked by Dakota Electric's coding system, such as installations for new development and service connections, the relationship to the above categories was quite clear. For other activities, such as underground cable replacement or overhead line replacement, the category assignment was less straight forward. The difficulty associated with assigning costs is illustrated with the following example. Dakota Electric has decided to replace an overhead line. The line is old and, because of its age, is weaker and considered a reliability risk. Due to these factors, the line was replaced. Since the line has deficiencies that fall into two categories, it begs the question, "should this be placed into the Age-Related replacement category or the Reliability replacement category?" For overhead lines, Dakota Electric placed most of these costs in the age-related category as these projects are primarily selected by age to improve reliability.

Turning to underground cable replacements, the selection of these projects was by the number of failures (outages) experienced by the cable. The underground replacement projects are selected not by age but by the need to improve reliability. However, since the underground cable replacement project does not increase system capacity, these projects were also included in the age replacement category. Dakota Electric placed these projects in this category because the underground cables replaced tended to be among the older underground cables on the system.

Projects which were driven by member requests, such as conversion of the electrical service to their homes from overhead wire to underground, were included in the System Projects (Driven by Government) category as that appeared to be the best fit for those projects.

The information in the above historical capital spending table clearly shows the impact of Dakota Electric's AGi advanced metering project. This impact is illustrated by the significant increase in spending starting in 2020. These increases are related to the cost of new meters and load control receivers. The cost of the new meters was placed in the metering category and the cost of the new load control receivers was included in the advanced technologies category. The advanced categories category also includes costs associated with the RF Mesh system which was installed in 2020.

The historical capital expenditures presented in the 2021 IDP Report for the years 2018, 2019, and 2020 have remained unchanged. In the 2021 IDP Report, the capital expenditures for 2021 and 2022 were forecasted. In the above table, the years 2021 and 2022 are now historical numbers. Below is a comparison between those forecasted numbers and the actual expenditures broken into the IDP categories.

Table 38. Comparison of 2021 & 2022 IDP Forecasted Capital Expenditures vs Actual

	2021 Forecast	2021 Actual		2022 Forecast	2022 Actual
Age Related Replacement	$2,235	$2,426		$2,904	$3,108
System Expansion (Due to Capacity)	$3,348	$3,263		$3,045	$2,772
System Expansion (Due to Reliability)	$1,052	$1,176		$1,357	$1,225
New Members	$4,473	$4,561		$4,605	$5,782
System Project (Driven by Mandate)	$1,734	$1,532		$1,893	$1,659
Metering	$11,921	$12,381		$499	$0
Grid Modernization (Advanced Technologies)	$2,972	$3,348		$4,169	$3,950
Annual Total	**$27,736**	**$28,687**		**$18,471**	**$18,495**

The 2021 total dollar expenditures were up slightly due to the ability to complete more of the AGi meter and load control receiver installations in 2021 than expected. These accelerated installations are apparent when looking at the expenditure differences in the Metering and Grid Modernization categories. The actual 2022 expenditures were surprisingly close to the totals for 2022 which were forecasted in 2021. Typically, given all the variables and moving components, the actual versus forecast is normally not this close. Overall, delays in projects due to COVID reduced expenses, while inflation due to supply chain issues increased expenses. The impact of these two variables offset each other.

The replacement of age-related equipment and system expansion were very close to the budgeted values due to limited unexpected projects and because most of the equipment had been contracted in 2020 and 2021, at those prices, for these planned projects. As such, these projects were not significantly impacted by the supply chain and inflation issues discussed earlier in this IDP Report. The New Member category was impacted by the higher costs of transformers and other equipment and was greater than forecasted. Within the Metering category, due to supply chain impacts, availability of meters to complete the AGi project were not available in 2022 and thus meter exchanges for those meters were not completed in 2022. As a result, Meter expenditures within this category in 2022 were below forecasted values. The Grid Modernization category includes expenditures for the AGi load control receiver replacements. In 2022, Dakota Electric identified issues with certain pieces of equipment supplied by the manufacturer. This issue required crews to be redirected to resolve the identified issues and reduced the number of new locations and their devices which were able to be exchanged. As a result, the total expenditure for this category was below forecasted levels.

aa) Financial Data: Investments in Distribution System Upgrades

Section A.27. 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).

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 2018-2022. 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 2021, and it was significantly higher than the prior three years. These significantly higher CIAC costs were primarily due to increased payments from new residential developments. In 2022, the contributions from new development were lower than 2021, but they were still higher than typical levels received because of larger street lighting projects.

Table 39. Historical Contribution-In-Aid-of-Construction

	2018	2019	2020	2021	2022
Age Related Replacement	$0	$316	$126	$169	$145
System Expansion (Due to Capacity)	$0	$0	$0	$5	$28
System Expansion (Due to Reliability)	$0	$0	$0	$0	$0
New Members	$1,301	$1,982	$1,419	$2,484	$2,330
System Project (Driven by Mandate)	$890	$164	$149	$400	$68
Metering	$0	$0	$0	$0	$0
Grid Modernization (Advanced Technologies)	$0	$0	$0	$0	$0
Annual Total	**$2,191**	**$2,462**	**$1,694**	**$3,058**	**$2,572**

Note: All dollars are in Thousands

bb) Financial Data: Projected Distribution System Spending

Section A.28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects.

This section presents the forecasted 5-year construction capital spend for the requested categories. When looking at the construction capital spending forecast, it is important to understand how Dakota Electric selects projects for construction and how that process works. Dakota Electric completes a 5-year capital construction forecast to help identify periods of expected high or low future capital spending. Dakota Electric has a limited labor pool to accomplish projects and peaks in the capital spending require increases in labor while, on the other hand, valleys in capital spending create an under-utilized labor pool. The 5-year capital construction budget forecast attempts to identify periods of high and low spending and, if possible, allow Dakota Electric to consider shifting spending to other years to help reduce capital budget swings. It is important to note that the majority of individual projects are not identified or approved by the Dakota Electric Board beyond the next calendar year.

The allocation of the forecasted capital spending into the IDP required categories, shown in the following table, has been done using a similar engineering estimation process as was utilized for the historical capital spending. Since most of the distribution system construction is in response to requests for new services, road rebuilds by government, response to area load growth, or other requests which have short lead times, much of the capital spending forecast is based upon historical spending within the internal financial categories. Only projects which require longer lead times, such as new distribution substations or projects which are driven by internal timelines, such age-related replacements, can be forecasted further out.

Figure 20. Substation Switchgear

Table 40. Five Year Forecast of Distribution System Spending

	2023	2024	2025	2026	2027
Age Related Replacement	$3,806	$4,242	$5,646	$6,687	$5,137
System Expansion (Due to Capacity)	$4,650	$4,501	$3,982	$3,061	$3,256
System Expansion (Due to Reliability)	$1,736	$1,777	$1,775	$1,594	$1,594
New Members	$4,765	$5,510	$5,727	$5,666	$5,495
System Project (Driven by Mandate)	$1,970	$1,966	$1,413	$1,222	$1,622
Metering	$123	$216	$10	$10	$10
Grid Modernization (Advanced Technologies)	$1,695	$1,376	$272	$257	$257
Other	$0	$0	$0	$0	$0
Annual Total	$18,746	$19,588	$18,825	$18,496	$17,371

Note: All dollars are in Thousands

The forecasted amounts in the above table are current as of October 2023. These figures are net values and reflect the expected reduction in actual costs due to material salvage. It is important to note that these amounts may change because the budget process for 2024 is on-open and has not yet been reviewed, and approved, by the Dakota Electric Board. Dakota Electric also notes that it has submitted projects for New ERA funding. New ERA projects have not yet been finalized, or awarded, and are not included in the above table.

The above table includes the remaining AGi project budgeted capital spending in the years 2023-2024. There are a few remaining AGi meter exchanges in 2023 and 2024, in the metering category, and the remaining exchange of Load Control Receivers is included in the Grid Modernization category for years 2023-2024.

Dakota Electric provides a discussion for each cost category below and how the 5-year budget forecast is accomplished for these categories. 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 consumers or main lines, 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 current growth expectations.

Supply Chain and Inflation Impacts

The cost of materials within the electric industry, especially transformers and cable, have increased significantly over the past few years. Dakota Electric notes that price increases of 100-200% for equipment are not uncommon.

Substation

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. Forecasting and scheduling substation projects to avoid multiple substation projects occurring in the same year, is important to avoid budget volatility, and accompanying impacts on labor resources, as discussed earlier in this section. Capital dollars for new substations or projects to increase the capacity of a substation are included in the System Expansion (Due to Capacity) category. Projects to replace aging substation equipment are included in the Age-Related Replacement category.

Over the next decade, 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 seniors. 8 substation transformers are over 40 years old and 3 more are over 30 years old. Also 6 substations have switchgear which is 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 being scheduled for replacement. Estimated expenditures for these projects are included in this forecast.

Reliability and Age-Related Replacement Projects

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. If there is a high number of these other projects, the available labor pool is less resulting in fewer reliability and age-related replacement projects being completed. However, if the failure rate of the existing underground cables or overhead lines tracks higher than average, more dollars are budgeted, and labor is allocated to this category.

Road Rebuild Projects

Local governments in our service territory provide multi-year forecasts of their respective road reconstruction projects. These projections are helpful for Dakota Electric to estimate the overall capital construction budget. However, the issue Dakota Electric faces is that the road reconstruction projects on the list provided are only in the concept phase. When a project is in the concept phase, it has not gone through the public hearing process and is not fully scoped or designed. Dakota Electric is only able to roughly estimate impacts to the distribution system and potential costs. The schedules provided by local governments for these projects are also only estimates. There are many other factors that can cause the actual road reconstruction to be canceled, greatly modified, or as routinely occurs, be delayed by one or more years. Dakota Electric becomes aware of when a project will occur when the project is released for bidding to contractors. When this occurs, Dakota Electric only has a couple of months (sometimes weeks) to work with the chosen contractor to prepare designs, order supplies, and start modifications to the distribution system in support of the road rebuild.

Technology Projects

Capital dollars for technology projects, such as adding remote control and monitoring to field equipment, are also forecasted for future years. Like age-related equipment replacements, these specific projects are not identified.

Comparisons between 2021 and 2023 Capital Forecasts

Below is a table showing the 2023-2025 forecast from the 2021 IDP report and the updated forecast for these years presented in this IDP Report.

Table 41. Comparison between 2021 and 2023 Capital Forecasts

	2023		2024		2025	
	From 2021 IDP	**Current**	**From 2021 IDP**	**Current**	**From 2021 IDP**	**Current**
Age Related Replacement	$2,814	$3,806	$2,741	$4,242	$2,741	$5,646
System Expansion (Due to Capacity)	$3,046	$4,650	$3,319	$4,501	$3,319	$3,982
System Expansion (Due to Reliability)	$1,389	$1,736	$1,306	$1,777	$1,306	$1,775
New Members	$4,153	$4,765	$4,238	$5,510	$4,378	$5,727
System Project (Driven by Mandate)	$1,825	$1,970	$1,789	$1,966	$1,789	$1,413
Metering	$10	$123	$10	$216	$10	$10
Grid Modernization (Advanced Technologies)	$2,817	$1,695	$464	$1,376	$464	$272
Other	$0	$0	$0	$0	$0	$0
Annual Total	$16,055	$18,746	$13,868	$19,588	$14,008	$18,825

Note: All dollars are in Thousands

Below is a category-by-category discussion on the differences between the 2021 IDP Report capital forecast and the 2023 IDP Report capital forecast:

Age Related Replacement: Some of the increase in this category is driven by significant increases in materials since the 2021 IDP report. There is also a significant increase in forecasted spending within this category due to a new set of projects which are rejuvenating aging substations. This includes replacing aging substation transformers and switchgear. These are large and costly projects which have recently been approved by the Board and added to the capital forecast.

System Expansion (Due to Capacity): The increases within this category are driven by significant increases in material costs. Since projects in this category are driven by actual growth in electrical demands, recent increases in feeder loading are also triggering new projects which were not anticipated in 2021. Overall system demand has been very flat over the past 10 years; however, recently, Dakota Electric has started to observe increased demand over peak periods for some of the system feeders, which is triggering projects to provide increased capacity to these areas.

System Expansion (Due to Reliability): The increases within this category are driven by increases in material costs. There have been no changes in the number of projects which fall into this category.

New Members: The spending forecasted within this category is driven by increases in the number of new services and cost increases due to material costs such as distribution transformers. Cost increases for distribution transformers is one item in particular which has been significant and one of the largest we have seen.

System Project (Driven by Mandate): This category is driven by requirements to move, or replace, existing equipment due to road rebuilds or other projects which are outside of the control and scheduling by the cooperative. The forecast of projects which fall into this category is based upon county and city transportation plans. As noted above, these plans often change. The schedule for when these projects are forecasted, versus when they are completed, is often quite different. There are many last-minute changes in the project schedule and project design. Design changes can affect the utility through changing which distribution facilities are impacted by the design change. A good example of this is the last-minute addition of walking paths to a road rebuild project. Initially, the road rebuild, without the walking path, had limited impact upon the existing distribution circuit, but, after the walking path was added, the poles and underground facility boxes may need to be relocated. Adding a walking path to a road rebuild project is a relativity small change for the road rebuild project, but it can have significant impacts to the existing distribution system.

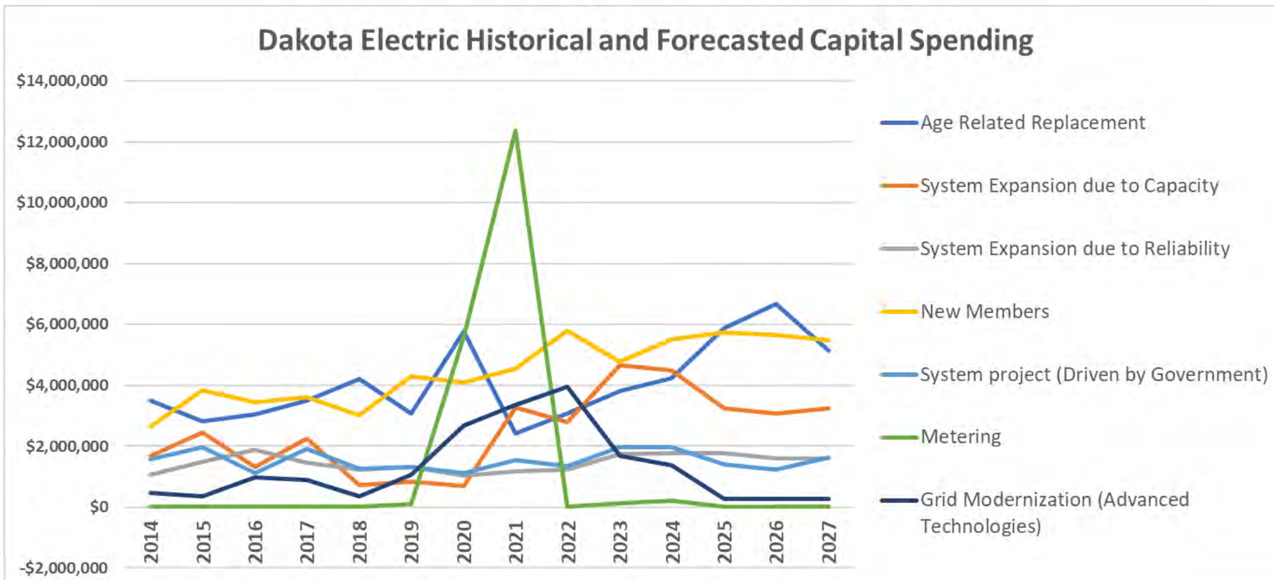
This category has also been impacted by higher material costs, but, comparing it year-to-year, the forecast for some years is up and some years it is reduced. This shows the dynamics of attempting to forecast the impacts to the distribution system from mandated projects.

Metering: This category is AGi metering costs. In 2021, the assumption was that completion of the meter exchanges would occur in 2022. Due to supply chain and vendor development delays, the remaining 1,000 meters needed to complete the AGi project did not start arriving until September 2023. The remaining meters are due to arrive over the following few months and should be exchanged to complete the metering portion of the AGi project in 2024. The increases in forecasted costs for 2023 and 2024 in this category reflect that delay in the AGi project meter exchange.

Grid Modernization (Advanced Technologies): The grid modernization category includes the replacement of the load control receivers as part of the AGi project. As with the meter exchange, there have been equipment and labor related delays with the load control receiver exchange. The 2023 dollars are lower than the 2021 forecasted numbers due to labor related delays in exchanging the devices on premises. The dollars have been moved from 2023 into 2024 and are showing an increase over the 2021 forecasted numbers. The receiver exchange is expected to be completed in 2024.

Below is a graph showing the historical and forecasted capital spending on the distribution system. The graph shows the increase in spending in 2020 and 2021 due to the AGi project advanced meter installations. Spending for the AGi project is also reflected in the graph values for the Grid Modernization category, showing the spending for the load management receiver replacements from 2020 through 2024. Increased spending in the Age-Related category is shown for years 2025-2027

Graph 24. Historical and Forecasted Capital Spending – Distribution System



cc) Financial Data: Planned Distribution Capital Projects

Section A.29. Planned distribution capital projects, including drivers for the project (e.g. see list in 19), timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:

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

After the discussion at the Commission's January 8, 2021 stakeholder meeting, it is understood that the focus of this question is on larger capital projects. For the 2023 IDP report, Dakota Electric is using a threshold of $250,000 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.

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. Dakota Electric's planned projects include what has not yet been completed in 2023 and what is proposed for 2024-2027.

The following table is a summary of the total dollars by IDP category and year, which are budgeted or forecasted. Only the capital dollars for identified projects over $250,000 are included in this table.

Table 42. Budgeted and Forecasted Capital Spending on Large Projects

	2023	2024	2025	2026	2027
Age Related Replacement	$0	$0	$2,450	$4,400	$0
System Expansion (Due to Capacity)	$3,885	$4,358	$3,530	$240	$240
System Expansion (Due to Reliability)	$1,199	$1,052	$1,100	$240	$240
New Members	$0	$0	$0	$0	$0
System Project (Driven by Mandate)	$1,581	$262	$0	$0	$0
Metering	$125	$225	$0	$0	$0
Grid Modernization (Advanced Technologies)	$1,500	$1,200	$0	$0	$0
Annual Total	$8,290	$7,097	$7,080	$4,880	$480

Note: All dollars are in Thousands

Appendix C lists construction projects for 2023-2024 that are considered larger projects. Many of these projects have been started and some have been completed in 2023. Due to the extended lead times for material and equipment, most of the materials for the planned and estimated 2024 projects have been approved by the Board and orders have been placed. During 2024, it is possible that some new projects will be identified; these projects could be due to large new load additions or road rebuild projects which are modified from initial scope and design. To accommodate these changes, existing projects may be deferred to allow the material ordered for them to be used on the new or updated projects.

Appendix D lists proposed construction projects for 2025-2027 which are considered larger projects. The list of projects for 2025-2027 is preliminary and has not been approved by the Dakota Electric Board. Given the extended lead times for cable, transformers, and other key materials, Board approval for purchasing supplies for required key inventory items has been accelerated (brought to the board sooner than normal) to allow future proposed and unplanned required projects to proceed.

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 September 2023. The listing is by type and overall kW. 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 much 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 Penetration

Section A.31. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER 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.

gg) 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. With the limited penetration 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 plans on using the advanced inverter settings to help reduce the chance of high voltage due to the operation of DER generation systems.

Since 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.

Appendix A – Sub & Feeder Minimum Load Information August 2022 – July 2023

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2022	2020	2018	2022	2020	2018	2022	2020	2018
Byllesby (2)	Substation	3,661	3,531	3,502	539	535	230	699	647	299
	1				54	73	63	54	77	64
	2				35	34	29	47	44	71
	3				141	133	88	152	146	122
	4				125	109	28	125	124	68
Hastings (3)	Substation	10,665	11,257	9,961	1,684	1,707	1,706	1,978	2,211	2,173
	1				1,111	1,077	603	1,412	1,466	1,431
	2				44	59	91	44	59	136
	3				161	232	178	178	232	218
	4				188	181	131	220	221	225
Castle Rock (4)*	Substation	3,028	3,445	3,029	555	549	577	728	749	743
	1				99	56	28	99	76	38
	2				33	68	70	33	68	75
	4				308	256	195	429	289	208
Burnsville North (5)	Substation	25,985	32,736	25,487	6,231	5,950	6,152	8,385	7,859	7,377
	1 (N)				1,031	526	1,063	1,193	526	1,226
	3 (N)				880	950	857	1,060	1,270	1,067
	5 (N)				509	139	649	623	139	770
	7 (N)				1,529	1,558	421	1,956	1,901	421
	9 (N)				824	253	837	934	319	1,085
	11 (N)				685	786	365	685	1,108	575
Burnsville South (5)	Substation	24,414	22,893	21,372	3,917	5,565	5,473	5,141	7,564	6,743
	2 (S)				203	449	1,498	300	449	1,883
	4 (S)				1,209	1,141	1,123	1,667	1,572	1,253
	6 (S)				351	1,608	1,534	374	2,034	2,033
	8 (S)				425	419	391	529	554	547
	10 (S)				262	275	276	349	375	346
Eagan (6)	Substation	9,571	10,103	9,051	2,027	1,731	2,138	2,542	2,418	2,833
	1				228	264	489	676	264	704
	2				139	210	141	139	250	144
	3				143	10	210	229	106	276
	4				358	353	353	401	448	406
	5				273	364	300	273	477	331
	6				95	113	162	95	217	235
Miesville (7)	Substation		6,919	6,643	1,266	1,240	1,034	1,323	1,431	1,510
	1				115	38	123	115	41	201
	2				293	296	136	354	382	136
	3				107	106	114	122	106	176
	4				165	169	105	165	169	140
	5				329	38	193	329	41	193
Orchard Lake (8)	Substation	22,619	20,017	19,119	4,731	4,322	3,922	5,761	5,949	5,104
	1				661	608	617	771	749	685
	2				752	791	189	956	973	189
	3				1,110	965	221	1,525	1,100	473
	4				344	71	190	372	71	247
	5				71	8	13	89	12	22
	6				806			1,148		

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2022	2020	2018	2022	2020	2018	2022	2020	2018
River Hills East (9)	Substation	12,058	12,966	12,486	2,850	2,817	2,844	3,216	4,049	4,021
	2				806	824	852	1,108	1,148	1,183
	3				318	110	315	337	395	351
	4				995	1,003	202	1,422	1,359	1,433
	8				375	320	300	579	459	446
	10				252	261	266	349	385	369
River Hills West (9)	Substation	11,824	11,849	11,470	2,601	2,644	1,804	3,421	3,471	2,678
	1				478	298	582	478	756	749
	5				775	653	182	1,033	653	182
	6				708	756	731	919	1,051	1,069
	7				411	12	20	533	117	20
Yankee Doodle North (10)	Substation	13,942	12,141	14,095	3,866	3,632	4,053	4,163	4,100	4,511
	1				841	849	1,006	1,197	879	1,591
	3				639	625	298	828	828	830
	5				1,355	940	491	1,379	940	1,033
	7				405	324	175	734	541	230
Yankee Doodle South (10)	Substation	13,885	12,417	14,476	5,262	4,312	2,727	5,340	4,341	2,834
	2				3	3	3	3	3	3
	4				817	141	138	1,063	141	138
	6				467	339	505	648	453	505
	8				1,852	1,449	258	2,278	2,126	258
	10				166	111	94	201	112	126
Fischer West (11)	Substation	20,014	19,738	24,086	4,536	4,175	4,708	6,129	6,482	6,628
	1				297	419	285	520	610	548
	2				1,430	1,573	1,566	1,776	1,876	1,907
	7				569	648	650	790	850	851
	9				679	683	684	897	958	896
	10				154	156	161	165	182	214
Fischer East (11)	Substation	24,689	21,260	33,134	5,239	5,278	5,207	5,239	6,952	7,488
	3				1,104	1,251	1,291	1,104	1,540	1,630
	4				677	1,176	947	975	1,602	947
	5				159	253	258	159	330	284
	6				713	805	903	713	1,125	1,242
	8				965	1,118	660	1,056	1,868	701
Deerwood (12)	Substation	22,724	24,338	23,179	5,798	6,102	6,607	6,800	7,826	8,633
	1				397	678	808	542	768	992
	2				964	1,246	1,257	1,173	1,574	1,636
	3				611	867	922	675	1,274	1,247
	4				1,149	1,012	974	1,410	1,273	974
	5				1,292	1,215	1,365	1,514	1,874	1,845

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load 2022	Peak Load 2020	Peak Load 2018	Minimum 2022	Minimum 2020	Minimum 2018	Daytime Minimum 2022	Daytime Minimum 2020	Daytime Minimum 2018
Colonial Hills North (13)	Substation	16,588	16,675	19,828	4,249	4,764	4,832	5,921	5,899	6,523
	1				754	857	574	902	951	574
	3				162	164	197	168	301	339
	4				740	605	656	835	715	775
	8				1,027	1,011	597	1,500	1,011	867
	9				667	691	1,128	667	691	1,417
Colonial Hills South (13)	Substation	15,662	12,553	13,332	3,050	3,273	3,340	3,267	4,495	4,534
	2				665	263	759	970	394	1,312
	5				815	743	692	991	924	692
	6				330	356	399	430	498	515
	7				303	306	356	422	390	460
	10				635	630	694	917	833	841
LeMay Lake (14)	Substation	23,340	20,553	23,030	9,643	10,782	8,878	9,731	11,794	10,360
	1				3,458	1,890	1,266	4,360	2,593	1,266
	2				552	550	219	561	668	219
	3				786	780	778	948	849	1,032
	4				567	1,602	1,580	1,046	2,151	2,180
	5				1,001	1,007	429	1,386	1,361	429
	6				744	78	80	773	82	89
Lake Marion (15)	Substation	5,045	8,900	5,330	1,332	1,148	1,356	1,424	1,214	1,356
	1				400	140	404	400	218	404
	3				168	287	228	168	349	315
	4				483	543	473	596	592	604
Lebanon Hills (16)	Substation	20354	19,635	17,196	3,254	4,011	3,482	3,374	4,247	4,425
	1				324	523	489	342	661	621
	2				833	1,001	361	906	1,010	361
	3				839	784	519	1,009	994	876
	4				27	182	495	30	316	602
	5				36	311	281	38	311	385
	6				513	500	63	644	529	195
Dakota Heights (17)	Substation	21,862	14,516	22,548	3,608	4,267	3,664	4,815	4,780	4,155
	1				698	685	716	790	719	905
	2				583	730	599	726	893	735
	3				412	321	351	412	321	351
	4				728	525	194	995	853	196
	5				393	244	69	732	244	69
	6				424	447	456	605	609	610
Marshan (18)	Substation	7,112	6,762	5,862	134	413	314	134	413	314
	1				-578	-477	< 0	-578	-477	< 0
	2				278	276	83	300	332	222
	3				48	31	30	48	31	30
	4				215	166	158	215	219	158
Pilot Knob (19)	Substation	11,154	11,762	12,773	1,741	2,311	2,408	2,418	3,323	3,183
	1				255	264	257	363	402	356
	2				244	240	233	298	249	275
	3				176	200	218	223	210	268
	4				222	886	306	222	1,114	318
	5				644	647	697	891	895	894

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2022	2020	2018	2022	2020	2018	2022	2020	2018
Wescott Park East (20)	Substation	6,890	6,953	7,563	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	7,575	10,145	10,808	1,240	1,619	867	2,130	2,023	867
	2				0	0	0	0	0	0
	4				341	496	325	366	600	325
	6				321	364	361	321	477	399
	7				0	0	0	0	0	0
	8				0	981	99	0	1,335	293
Apple Valley (21)	Substation	21,971	22,423	21,587	5,475	5,468	5,577	6,562	6,012	6,379
	1				739	616	877	757	930	1,002
	2				561	1,150	1,141	701	1,334	1,168
	3				362	361	368	404	436	411
	4				602	642	309	840	801	335
	5				244	176	240	326	435	302
	6				919	937	503	1,181	1,068	503
Dodd Park South (22)**	Substation	18,772	30,139	24,678	3,434	5,673	4,608	4,364	6,680	4,608
	1				712	865	1,040	811	1,072	1,061
	2				639	629	351	798	906	379
	3				565	658	367	565	819	367
	4				98	985	684	98	1,164	787
	5				538	156	111	538	252	111
Dodd Park North (22)**	Substation	16,122			2,859			2,900		
	6				562	865	1,040	667	1,072	1,061
	7				544			544		
	8				938			1,119		
	9				231			352		
Empire (23)	Substation	3,938	3,920	3,938	530	452	512	610	646	600
	1				178	371	172	229	498	224
	2				86	138	136	86	152	158
	3				0	0	0	0	0	0
	4				76	105	102	76	125	120
Vermillion River (24)	Substation	11,977	15,345	11,296	739	318	1,868	739	318	2,809
	1				693	700	458	767	923	940
	2				257	137	146	257	260	239
	3				-2,593	-2,628	236	-2,593	-2,628	300
	4				284	238	190	297	274	246
	5				146	159	166	172	165	169
	6				841	869	843	948	1,122	976
Lakeville (25)	Substation	29,206	28,113	23,981	6,199	5,862	4,800	6,398	8,368	7,229
	1				1,055	1,325	1,139	1,055	1,542	1,482
	2				802	767	222	1,034	1,066	222
	3				741	839	464	741	1,396	623
	4				851	854	832	1,087	1,143	1,140
	5				704	696	492	718	1,005	492
	6				1,146	945	316	1,705	1,514	758

Feeder Minimum Loading Levels

Substation	Feeder	Peak Load			Minimum			Daytime Minimum		
		2022	2020	2018	2022	2020	2018	2022	2020	2018
Kenrick (26)	Substation	8650	9,832	7,294	2,967	1,582	2,149	3,357	2,129	2,820
	1				121	121	53	155	164	53
	2				1,180	759	601	1,238	922	690
	3				72	384	306	260	475	396
	4				840	961	986	1,159	1,103	1,132
Ritter Park (27)	Substation	16653	17,155	16,837	4,200	3,735	3,077	5,188	4,781	3,907
	2				1,193	1,084	189	1,427	1,375	189
	3				739	568	570	779	788	570
	4				1,536	1,454	372	1,665	2,249	538
	5				405	369	257	439	419	388
Barnes Grove* (28)**	Substation	5364			728			838		
	1				119			119		
	2				175			194		
	3				301			324		
Nininger (29)	Substation	4131	3,910	3,315	629	634	616	629	926	847
	1				157	195	117	294	299	216
	3				283	251	226	324	356	268
	4				141	142	120	197	179	180
Ravenna (30)	Substation	7098	6,810	7,680	649	619	652	1,028	1,027	721
	1				0	0	0	0	0	0
	3				171	163	293	171	163	342
	4				136	163	152	136	185	167
Burnscott (31)	Substation	10714	10,730	11,656	2,136	1,653	1,556	2,462	2,246	2,520
	1				554	428	367	744	428	367
	2				129	148	455	186	150	588
	3				510	421	404	610	432	513
	4				296	303	N/A	296	397	N/A
Randolph (32)	Substation	5227	4,254	3,308	-1,061	-1,117	< 0	-1,061	-1,108	< 0
	1				188	113	133	196	153	161
	2				101	102	87	131	108	87
	3				2	2	< 0	2	2	< 0
	4				107	61	14	107	141	20
		514,484	506,695	504,930						

*Backfeed of Castle Rock with VR is classified as abnormal operation and not included in the minimum load determination (Substation backfeed on 4/22/21, 10/9/21, 9/13/22 and 1/1/22)

**Dodd Park was converted to a double ended substation (North and South) in 2022 and the load split among the 10 feeders. Load data from Oct 2022 to July 2023

***New Substation

Appendix B – DER Feeder Summary Report

	Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)									
Feeder	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
02FB01	12	33	9	27	9	106	13	831	2	25	22	98	0	0	0	0	1	20	0	0	0	0
02FB02	10	28	24	84	18	235	6	349	3	48	30	145	0	0	0	0	1	20	0	0	0	0
02FB03	31	100	4	15	8	117	1	47	1	1	15	68	0	0	1	426	0	0	0	0	0	0
02FB04	9	24	9	30	7	63	10	443	1	2	15	65	3	928	0	0	2	37	0	0	1	4
03FB01	672	1,740	19	54	23	160	1	65	5	25	88	396	0	0	0	0	9	67	0	0	1	8
03FB02	45	134	23	77	34	392	28	2,142	5	53	38	172	0	0	0	0	8	128	0	0	0	0
03FB03	50	143	32	117	25	420	35	2,437	3	10	47	213	0	0	0	0	3	51	0	0	0	0
03FB04	55	156	20	64	29	238	22	1,415	2	17	21	95	0	0	0	0	3	26	1	20	0	0
04FB01	36	108	13	49	18	196	3	130	0	0	29	125	0	0	1	115	2	46	0	0	0	0
04FB02	25	74	15	52	15	215	3	129	4	25	27	124	0	0	0	0	6	114	0	0	0	0
04FB04	272	853	109	439	168	1,804	5	252	30	243	260	1,173	2	184	0	0	22	338	4	42	0	0
05FB01	648	2,081	48	170	30	145	0	0	9	39	50	225	1	216	0	0	19	131	0	0	1	10
05FB02	661	1,872	12	40	20	113	0	0	4	19	40	180	3	1,728	0	0	17	122	0	0	0	0
05FB03	494	1,616	21	80	18	94	0	0	5	18	43	189	0	0	0	0	12	89	0	0	0	0
05FB04	851	2,235	13	48	22	86	0	0	1	1	3	14	1	559	0	0	2	17	0	0	1	10
05FB05	473	1,421	12	37	31	162	0	0	6	18	15	68	0	0	0	0	9	79	0	0	0	0
05FB06	201	635	4	13	11	68	0	0	2	7	5	23	5	1,614	1	737	4	29	0	0	0	0
05FB07	52	161	2	11	6	38	0	0	3	14	3	14	3	372	0	0	0	0	0	0	0	0
05FB08	470	1,315	8	25	13	48	0	0	1	5	60	270	2	407	1	737	7	54	0	0	0	0
05FB09	601	1,890	22	72	33	162	0	0	10	33	32	145	1	167	0	0	8	57	0	0	0	0
05FB10	204	625	13	44	10	39	0	0	5	8	18	83	0	0	0	0	1	21	0	0	0	0
05FB11	812	2,351	34	108	28	144	0	0	10	28	18	76	0	0	0	0	14	102	0	0	0	0
06FB01	205	665	28	97	13	78	0	0	1	3	10	45	1	806	0	0	12	75	0	0	0	0
06FB02	173	512	6	21	6	42	0	0	1	6	9	42	0	0	0	0	8	67	0	0	0	0
06FB03	135	430	6	19	3	19	0	0	1	4	23	104	0	0	0	0	9	64	0	0	0	0
06FB04	297	934	18	61	5	17	0	0	1	5	7	32	0	0	0	0	9	65	0	0	0	0
06FB05	234	749	27	90	9	42	0	0	2	6	10	45	0	0	0	0	17	125	0	0	0	0
06FB06	78	229	5	17	12	97	0	0	0	0	4	18	1	461	0	0	1	2	0	0	0	0
07FB01	44	126	10	44	20	308	13	1,024	7	21	25	107	0	0	0	0	3	61	0	0	0	0
07FB02	86	243	17	55	27	259	5	442	8	54	42	190	0	0	0	0	3	32	1	13	0	0
07FB03	30	105	21	76	30	324	1	111	3	14	41	180	0	0	0	0	5	88	0	0	0	0
07FB04	34	112	34	137	51	1,030	16	1,128	14	79	52	249	0	0	0	0	8	119	0	0	0	0
07FB05	86	265	38	200	46	640	12	843	7	72	82	370	0	0	0	0	3	86	0	0	0	0
08FB01	378	1,170	39	142	54	564	0	0	17	110	89	400	0	0	0	0	15	152	0	0	0	0
08FB02	498	1,419	18	59	19	173	0	0	4	17	79	354	1	98	2	0	4	32	0	0	0	0
08FB03	486	1,463	19	68	22	124	0	0	3	11	30	134	1	49	0	0	11	100	0	0	0	0

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	Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)									
Feeder	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
08FB04	448	1,354	23	87	45	372	0	0	10	32	77	341	0	0	0	0	6	43	0	0	0	0
08FB05	57	165	4	13	5	62	0	0	1	1	4	18	1	645	0	0	3	16	0	0	0	0
08FB06	288	964	26	104	55	509	0	0	9	119	104	468	0	0	0	0	4	38	0	0	0	0
09FB01	472	1,060	7	19	5	22	0	0	1	3	26	117	1	338	0	0	5	39	0	0	0	0
09FB02	678	1,866	27	85	15	90	0	0	4	15	110	486	0	0	0	0	9	63	0	0	0	0
09FB03	350	1,035	14	45	17	114	0	0	3	7	30	135	0	0	0	0	15	90	0	0	1	0
09FB04	346	1,094	19	79	12	166	0	0	3	9	23	101	0	0	0	0	9	67	0	0	0	0
09FB05	553	1,595	14	40	10	37	0	0	3	9	46	242	0	0	0	0	4	38	0	0	0	0
09FB06	314	871	4	12	5	21	0	0	0	0	2	9	0	0	0	0	0	0	0	0	0	0
09FB07	213	638	5	15	3	12	0	0	0	0	5	23	0	0	0	0	1	6	0	0	0	0
09FB08	37	112	0	0	0	0	0	0	0	0	1	5	0	0	0	0	1	20	0	0	0	0
09FB10	322	815	6	22	5	22	0	0	1	4	161	720	0	0	0	0	2	13	0	0	0	0
10FB01	21	98	1	46	0	0	0	0	0	0	0	0	1	1,116	0	0	0	0	0	0	0	0
10FB02	0	0	0	0	0	0	0	0	0	0	0	0	1	3,900	0	0	0	0	0	0	0	0
10FB03	388	1,165	25	88	26	134	0	0	2	7	38	171	1	230	0	0	16	125	0	0	0	0
10FB04	9	43	0	0	0	0	0	0	0	0	1	5	2	735	0	0	1	45	0	0	0	0
10FB05	78	277	0	0	0	0	0	0	0	0	1	5	1	1,202	0	0	1	30	0	0	0	0
10FB06	96	317	9	40	12	145	0	0	0	0	23	104	0	0	2	1,037	4	34	0	0	0	0
10FB07	128	378	4	14	3	23	0	0	0	0	6	26	1	575	0	0	5	46	0	0	0	0
10FB08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10FB10	2	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11FB01	91	281	2	7	0	0	0	0	1	2	5	18	3	710	0	0	1	6	0	0	0	0
11FB02	236	600	5	13	25	182	0	0	0	0	2	9	6	2,818	0	0	0	0	0	0	0	0
11FB03	259	802	8	61	3	42	0	0	0	0	7	30	1	691	0	0	1	7	0	0	0	0
11FB04	372	1,064	18	53	12	64	0	0	2	6	8	36	2	1,085	0	0	13	84	0	0	0	0
11FB05	197	576	15	51	11	58	0	0	2	10	13	59	0	0	0	0	1	10	0	0	0	0
11FB06	228	644	4	16	3	27	0	0	0	0	55	248	1	725	0	0	3	21	0	0	0	0
11FB07	138	426	0	0	0	0	0	0	0	0	0	0	4	621	0	0	0	0	0	0	0	0
11FB08	586	1,634	19	61	15	80	0	0	1	2	11	50	0	0	0	0	16	110	0	0	0	0
11FB09	725	1,980	24	68	26	107	0	0	2	6	10	41	0	0	0	0	10	73	0	0	0	0
11FB10	151	400	0	0	5	17	0	0	0	0	2	9	0	0	1	1,142	7	41	0	0	0	0
11FB11	305	699	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11FB12	836	2,420	26	80	34	161	0	0	3	8	59	266	0	0	0	0	35	274	0	0	0	0
12FB01	347	1,101	24	97	19	86	0	0	5	19	41	185	2	3,288	0	0	12	101	0	0	0	0
12FB02	518	1,584	29	87	45	445	0	0	2	5	163	732	2	1,135	0	0	15	125	0	0	0	0
12FB03	586	1,573	7	21	12	65	0	0	4	15	4	15	2	672	0	0	2	16	0	0	0	0

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	Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)									
Feeder	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
12FB04	718	1,978	22	71	17	102	0	0	1	21	15	68	0	0	0	0	8	46	0	0	0	0
12FB05	1,076	2,902	24	75	19	101	0	0	4	20	242	1,091	1	415	0	0	19	157	0	0	0	0
13FB01	335	972	9	30	3	9	0	0	2	10	7	32	2	552	0	0	4	79	0	0	0	0
13FB02	34	175	0	0	0	0	0	0	0	0	0	0	1	835	0	0	0	0	0	0	0	0
13FB03	0	0	0	0	0	0	0	0	0	0	0	0	1	3,384	0	0	0	0	0	0	0	0
13FB04	281	916	14	46	6	26	0	0	5	32	39	176	1	256	0	0	5	36	0	0	0	0
13FB05	86	205	0	0	5	43	0	0	0	0	65	333	0	0	0	0	0	0	0	0	0	0
13FB06	188	579	7	24	9	42	0	0	0	0	9	32	0	0	0	0	6	48	0	0	0	0
13FB07	23	198	0	0	0	0	0	0	0	0	3	14	3	940	0	0	0	0	0	0	0	0
13FB08	23	66	1	3	1	18	0	0	0	0	0	0	3	835	0	0	1	12	0	0	0	0
13FB09	325	929	8	27	8	46	0	0	1	1	65	287	3	1,110	1	0	1	5	0	0	0	0
13FB10	2	10	0	0	0	0	0	0	0	0	0	0	2	843	0	0	0	0	0	0	0	0
14FB01	0	0	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14FB02	8	23	0	0	0	0	0	0	1	0	1	5	2	690	0	0	0	0	0	0	0	0
14FB03	409	1,096	10	31	14	61	0	0	1	6	15	68	0	0	0	0	12	82	0	0	0	0
14FB04	178	475	1	3	3	20	0	0	0	0	8	36	1	520	0	0	1	6	0	0	0	0
14FB05	105	364	0	0	0	0	0	0	0	0	2	9	2	781	0	0	1	133	0	0	0	0
14FB06	220	792	5	15	1	7	0	0	2	8	42	188	1	1,100	0	0	0	0	0	0	0	0
16FB01	288	900	26	89	21	149	0	0	3	14	29	131	0	0	0	0	15	111	0	0	0	0
16FB02	430	1,440	45	179	98	922	0	0	20	158	156	701	0	0	0	0	18	126	0	0	0	0
16FB03	358	1,180	38	128	38	359	0	0	18	110	97	440	1	288	0	0	27	217	0	0	0	0
16FB04	339	1,086	36	121	17	81	0	0	8	74	31	140	1	675	0	0	26	211	0	0	1	4
16FB05	379	1,096	24	74	11	39	0	0	2	4	13	59	0	0	0	0	11	84	0	0	0	0
16FB06	222	771	39	182	47	449	1	102	17	73	93	423	0	0	0	0	12	137	0	0	2	14
17FB01	495	1,506	36	112	33	273	0	0	6	19	24	108	0	0	0	0	8	60	0	0	0	0
17FB02	360	1,161	16	51	22	184	0	0	12	32	79	356	0	0	0	0	14	98	0	0	1	5
17FB03	327	1,026	18	63	27	239	0	0	3	11	43	194	0	0	0	0	12	98	0	0	0	0
17FB04	187	608	8	27	22	147	0	0	6	39	46	207	4	1,558	0	0	10	91	0	0	0	0
17FB05	424	1,278	19	59	27	169	0	0	3	16	31	141	0	0	0	0	3	26	0	0	0	0
17FB06	337	952	16	59	7	35	0	0	2	7	24	108	1	625	0	0	5	29	0	0	0	0
18FB01	173	490	56	187	44	484	16	1,218	16	61	89	400	0	0	0	0	25	1,205	1	12	1	1
18FB02	141	410	20	76	29	306	3	312	9	104	49	222	0	0	0	0	4	48	0	0	0	0
18FB03	14	43	10	42	6	78	9	663	4	34	14	63	0	0	0	0	1	13	0	0	0	0
18FB04	58	172	16	58	22	160	20	1,408	6	102	33	147	0	0	1	202	4	100	0	0	0	0
19FB01	226	676	16	54	11	86	0	0	2	10	10	45	0	0	0	0	4	29	0	0	0	0
19FB02	243	759	24	83	30	201	0	0	5	17	27	117	0	0	0	0	2	11	0	0	0	0

	Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)									
Feeder	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
19FB03	149	457	16	100	9	50	0	0	4	45	29	132	0	0	0	0	0	0	0	0	0	0
19FB04	727	2,264	58	207	100	869	0	0	10	115	146	651	0	0	0	0	15	111	0	0	1	10
19FB05	358	1,183	15	55	21	99	0	0	3	8	14	63	0	0	0	0	10	75	0	0	0	0
20FB01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20FB02	0	0	0	0	0	0	0	0	0	0	0	0	3	5,800	0	0	0	0	0	0	0	0
20FB03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20FB04	164	560	19	85	31	268	0	0	6	12	35	158	0	0	0	0	5	40	0	0	0	0
20FB05	0	0	0	0	0	0	0	0	0	0	0	0	1	10,500	0	0	0	0	0	0	0	0
20FB06	233	836	24	85	21	164	0	0	1	2	25	113	0	0	0	0	7	57	0	0	0	0
20FB07	0	0	0	0	0	0	0	0	0	0	0	0	1	3,050	0	0	0	0	0	0	0	0
21FB01	379	1,203	19	65	8	21	0	0	5	12	16	71	2	2,715	0	0	11	83	1	20	0	0
21FB02	844	2,582	36	127	46	245	0	0	8	27	121	545	2	884	0	0	11	103	0	0	1	5
21FB03	280	853	21	79	11	61	0	0	6	23	15	68	0	0	0	0	6	50	0	0	0	0
21FB04	335	1,019	23	85	14	94	0	0	2	4	17	77	2	1,440	1	80	9	62	0	0	1	10
21FB05	93	303	11	39	9	54	0	0	1	1	5	23	1	936	0	0	1	8	0	0	0	0
21FB06	725	2,001	33	108	26	139	0	0	4	31	49	216	0	0	0	0	7	49	0	0	1	10
22FB01	496	1,375	26	76	22	94	0	0	4	8	27	122	0	0	0	0	9	77	0	0	0	0
22FB02	463	1,290	20	59	14	69	0	0	0	0	26	117	1	94	0	0	4	25	0	0	0	0
22FB03	437	1,279	14	42	15	97	0	0	6	20	76	342	0	0	0	0	31	259	0	0	0	0
22FB04	140	442	1	4	6	32	0	0	1	6	100	450	0	0	0	0	16	91	0	0	0	0
22FB05	317	925	23	79	7	42	0	0	1	1	47	212	0	0	0	0	8	57	0	0	0	0
22FB06	226	646	12	41	14	124	0	0	5	14	41	185	2	218	1	547	12	76	0	0	0	0
22FB07	526	1,546	6	25	20	194	0	0	2	19	141	629	0	0	0	0	55	351	0	0	3	20
22FB08	528	1,518	12	40	21	136	0	0	2	7	86	387	1	642	0	0	40	306	0	0	0	0
22FB09	450	1,367	46	152	28	140	0	0	6	10	177	797	1	250	0	0	15	126	0	0	0	0
23FB01	61	174	19	58	29	249	20	1,116	3	8	41	185	0	0	0	0	2	14	0	0	0	0
23FB02	48	146	38	123	41	466	26	1,710	7	79	67	300	0	0	0	0	5	53	0	0	0	0
23FB04	27	81	24	97	29	450	4	193	4	9	39	176	1	97	0	0	3	46	0	0	0	0
24FB01	600	1,703	21	63	32	258	0	0	2	6	62	278	1	92	1	264	23	182	0	0	1	0
24FB02	71	209	16	57	41	401	10	563	3	41	46	210	1	350	0	0	9	136	0	0	0	0
24FB03	63	185	27	115	24	418	3	120	1	8	52	234	0	0	0	0	1	3,000	0	0	0	0
24FB04	18	65	6	33	12	150	10	454	0	0	18	78	1	180	0	0	1	15	0	0	0	0
24FB05	5	15	1	3	4	34	0	0	0	0	4	18	0	0	1	893	0	0	0	0	0	0
24FB06	830	2,229	13	42	15	95	0	0	5	16	68	304	0	0	0	0	23	160	0	0	0	0
25FB01	1,031	2,575	24	66	27	160	0	0	2	16	17	77	0	0	1	383	39	242	0	0	0	0
25FB02	512	1,500	32	99	22	140	0	0	5	23	116	522	0	0	1	0	13	86	0	0	0	0

Appendix B – DER Feeder Summary Report

	Load Control Receiver Loads (kW assumes zero diversity)												DER Systems (kW is DER AC rating)									
Feeder	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
25FB03	380	1,010	5	22	43	325	0	0	3	13	25	113	1	0	0	0	29	213	0	0	1	5
25FB04	928	2,271	21	63	6	39	0	0	5	18	222	999	0	0	0	0	23	168	0	0	0	0
25FB05	820	1,835	4	12	8	52	0	0	1	5	316	1,415	0	0	0	0	8	55	0	0	0	0
25FB06	420	1,125	3	9	9	86	0	0	0	0	15	68	2	778	0	0	17	125	0	0	1	10
26FB01	108	271	5	14	4	49	0	0	3	4	3	14	0	0	0	0	0	0	0	0	0	0
26FB02	233	712	30	104	55	562	1	30	13	157	75	332	0	0	2	384	22	158	0	0	0	0
26FB03	173	679	32	136	61	650	0	0	12	114	84	379	0	0	0	0	13	190	0	0	1	10
26FB04	295	930	59	258	84	893	1	5	35	274	119	536	3	852	0	0	2	31	0	0	1	0
27FB02	30	148	4	14	3	129	0	0	1	12	7	32	3	1,380	0	0	3	45	0	0	0	0
27FB03	185	638	15	55	28	225	0	0	8	20	41	183	1	965	0	0	6	53	0	0	0	0
27FB04	744	2,341	30	99	51	442	0	0	8	46	296	1,307	1	706	0	0	51	448	0	0	1	7
27FB05	127	393	9	34	10	86	0	0	5	27	40	182	1	770	0	0	2	22	0	0	0	0
28FB01	57	182	12	52	13	123	0	0	7	71	29	135	0	0	0	0	3	29	0	0	0	0
28FB02	3	9	2	7	0	0	0	0	0	0	2	9	0	0	1	200	0	0	1	38	0	0
28FB03	97	330	23	88	32	294	0	0	7	61	25	113	1	0	0	0	8	76	0	0	0	0
29FB01	141	343	7	20	20	148	1	88	1	5	55	249	0	0	0	0	3	48	0	0	0	0
29FB03	165	454	6	20	23	212	2	52	8	32	23	104	0	0	0	0	6	43	0	0	0	0
29FB04	44	124	9	35	22	288	17	1,405	1	40	35	165	0	0	0	0	0	0	0	0	0	0
30FB01	0	0	0	0	0	0	0	0	0	0	0	0	1	4,900	0	0	0	0	0	0	0	0
30FB03	37	109	10	45	24	241	0	0	6	23	30	135	0	0	0	0	2	44	0	0	0	0
30FB04	51	143	14	38	11	144	3	74	1	14	12	54	0	0	0	0	1	8	0	0	0	0
31FB01	349	870	10	30	14	70	0	0	3	10	9	39	0	0	0	0	1	36	0	0	0	0
31FB02	0	0	0	0	0	0	0	0	0	0	0	0	2	2,230	1	1,048	0	0	0	0	0	0
31FB03	293	757	8	23	3	6	0	0	0	0	6	27	1	569	1	878	3	25	0	0	0	0
31FB04	19	140	0	0	0	0	0	0	0	0	0	0	1	311	0	0	0	0	0	0	0	0
32FB01	33	94	19	70	42	507	11	586	4	22	44	196	0	0	0	0	0	0	0	0	0	0
32FB02	20	93	14	50	23	326	6	315	1	20	35	158	0	0	0	0	2	13	1	10	0	0
32FB03	1	3	1	3	2	43	1	47	0	0	2	10	0	0	1	276	0	0	0	0	0	0
32FB04	89	246	53	179	61	649	48	2,409	8	63	106	476	0	0	1	188	9	100	0	0	1	5
32FB05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2,000	0	0	0	0
174	**45,813**	**133,657**	**2,748**	**9,831**	**3,290**	**29,055**	**387**	**24,657**	**649**	**3,916**	**7,200**	**32,384**	**126**	**84,191**	**24**	**9,537**	**1,325**	**17,360**	**10**	**154**	**24**	**148**

Appendix C – 2023-2024 In Progress Capital Construction Projects > $250,000

The following is a discussion of capital projects which are completed, or in progress, and scheduled to be completed by the end of 2024 and have an overall estimated cost greater than $250,000.

AGi project – Approved in Docket No. E111/M-17-821.
The AGi project is nearing completion. $400,000 was budgeted for completing meter replacement in 2023, but delivery of the 320-amp meters with internal switches was again delayed. In September 2023, a small group of meters were delivered and installed. The remaining meters are expected to be delivered in groups at the end of 2023 and first few months of 2024. The estimated spending for meter replacements is $125,000 in 2023 and $225,000 in 2024. These dollars are included in the Metering category.

Load Control Receiver (LCR) replacement was budgeted for completion in 2023, but, due to labor availability issues, there has been a slowdown in the LCR replacements per month in 2023. This is pushing the replacement for some of the LCRs into 2024. $1.5 Million is expected to be spent on LCR replacement in 2023 and $1.2 million expected to be spent in 2024 to complete the AGi LCR replacement project. The dollars for the LCR replacement are included in the Grid Modernization (Advanced Technologies) category.

Cedar Substation
The new Cedar Substation is scheduled to be completed by the end of 2023. $2.2 million is budgeted in 2023 to complete this substation. This substation is being built to provide increased capacity for the fast-growing eastern Lakeville and northern Farmington areas and is included in the System Expansion (Due to Capacity) category.

Feeders for Cedar Substation
To integrate the new Cedar substation with the distribution system, new circuits (feeders) are being installed. The substation will have 5 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 2023 budget for these feeders is $2.43 million. These feeders are being installed and will be energized by the end of 2023. The dollars have been allocated between two IDP categories. 60% of the project was included in the System Expansion (Due to Capacity) and 40% of the project was included in System Expansion (Due to Reliability). The driver for the substation and the associated feeders is to provide more capacity and to maintain reliability. It is unclear which category projects such as this should be placed into as they do easily fit into multiple categories. There is a system expansion for capacity components and the need for capacity is being driven by adding new members. The new members category could have also been used for the allocation. Since this was not directly involved in directly connecting up new consumers to the distribution network, allocation to that category was not used.

New Eidswold Substation
This new substation is in the city of Elko-New Market. The substation is being constructed to provide capacity for the growing area south of Lakeville and Elko-New Market. The substation is also needed to provide contingency support for the loss of the Lake Marion or Castle Rock substations. City permitting for this substation has been completed and the process for obtaining approval for interconnection with the 115kV transmission line has also been completed. Design work for the substation and transmission

interconnection was completed over the past couple of years. Equipment is on order and is expected to be delivered and installed in 2024. The substation has a scheduled in-service date of December 2024. This date has been coordinated with the transmission owner, Xcel Energy, and Dakota Electric's transmission provider, Great River Energy. The cost for this substation is spread over 2023 and 2024 expenditures and is budgeted to cost $2.9 million. These costs do not include the Great River Energy transmission expenditure. The costs for this substation are included in the System Expansion (Due to Capacity) category.

Feeders for Eidswold Substation

To integrate the new Eidswold substation with the distribution system, new circuits (feeders) are being installed. The substation will have 5 new feeders which will supply power to the area in and around Elko-New Market. The new feeders are being installed mostly underground with 750 MCM cables. One feeder will be installed overhead and use 477 ACSR conductor. The total 2024 budget for these feeders is $1.6 million. These feeders are being installed and will be energized by the end of 2024, along with the substation energization. The dollars have been allocated between two IDP categories. 60% of the project was assigned to the System Expansion (Due to Capacity) and 40% of the project assigned to System Expansion (Due to Reliability).

Hastings Substation new Feeder #6

The City of Hastings continues to grow, especially to the south. This new feeder is required to provide increased capacity, maintain reliability, and power quality in the area. The growth is being driven by the construction of new homes and businesses. The new feeder is being budgeted for 2024 construction and involves 1.8 miles of underground cables. $430,000 is the estimate for this project. The dollars have been allocated between two IDP categories. 60% of the project was placed into the System Expansion (Due to Capacity) and 40% of the project assigned to System Expansion (Due to Reliability). As with the Cedar substation, the dollars for this new feeder could have been allocated in many ways.

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 2023, $756,000 is being allocated to these projects. In 2024, $800,000 is being allocated. 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. The costs for these projects are allocated 40% to the Age Related Replacement category, 30% to System Expansion (Due to Capacity), and 30% to System Expansion (Due to Reliability)

Road Realignment - Dakota County Road 91 – Hastings Area

This project is the result of rebuilding and expanding of the existing road with increased right-a-way (ROW). Dakota Electric needed to remove existing overhead lines and is using this opportunity to increase capacity by using a large size wire as part of the new 3-mile line being installed. Estimated project cost is $350,000 and is expected to be completed in 2023. This project was classified as 100% into the System Project (Driven by Mandate)

Road Realignment - Dakota County Road 59
This project is a result of rebuilding the existing road with increased right-a-way (ROW). Dakota Electric needed to remove the existing overhead line to support road realignment and rebuild a new line within the update road ROW. Project cost estimate for the 2.4-mile line rebuild is $261,000. This project is expected to be completed in 2023. This project was classified as 100% into the System Project (Driven by Mandate).

Road Rebuild – Dakota County Road 86 – Southern Dakota County
Dakota Electric needed to remove the existing overhead line to support road realignment and rebuild a new line within the updated road ROW. Project cost estimate for the 3.7-mile line rebuild is $530,000. This project is expected to be completed in 2024. This project was classified as 100% into the System Project (Driven by Mandate).

Road Rebuild – Dakota County 91 – Miesville Area
Dakota Electric and Great River Energy have been requested to rebuild the existing transmission and unbuilt distribution line farther out from the road. 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 2024. This project was classified as 100% into the System Project (Driven by Mandate).

New road construction – Burnsville Center – Aldrich Ave
This project is for a new road to be built through the existing Burnsville Center parking lot and through the area now occupied by the old Sears department store. This project will involve rebuilding existing electrical circuits and, in many portions, using larger, higher capacity underground cables. Design work and adjustments to the project scope continue to affect the impact of this project on the Dakota Electric distribution system. Dakota Electric recently received word that this project's schedule has been changed from a scheduled 2025 planned construction to early 2024 construction. Given that lead times for cable and other equipment is now 12 month or more, Dakota Electric will need to reallocate cables and supplies and possibly delay other planned work. This is typical of how little lead time Dakota Electric receives on major projects and is expected to be ready to rebuild existing facilities with little notice. The project is currently estimated at $410,000 and is scheduled for 2024 construction. This project was classified as 100% into the System Project (Driven by Mandate).

Appendix D – 2025-2027 Planned Capital Construction Projects > $250,000

The following is a discussion of capital projects which are being planned for construction in 2025-2027 and have an overall cost greater than $250,000.

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. For each of the years 2025-2027, $800,000 is forecasted. As was done for this same project in years 2023 & 2024, the costs for these projects are allocated 40% to the Age-Related Replacement category, 30% to System Expansion (Due to Capacity), and 30% to System Expansion (Due to Reliability).

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 million is forecasted in 2025 for this work. The driver for this expansion is new residential and commercial development in eastern Apple Valley and northeastern Lakeville. The dollars have been placed into the System Expansion (Due to Capacity) category.

Lakeville Feeders
With the addition of a second transformer at Lakeville substation, new feeders are required to support the additional capacity and maintain reliability for the area. The cost for the new feeders is estimated at $2.15 million. The costs have been allocated between two IDP categories. 60% of the project was placed to the System Expansion (Due to Capacity) and 40% of the project assigned to System Expansion (Due to Reliability).

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. The cost is estimated at $1.25 million. This cost has been included in the Age-Related Replacement category.

Fisher 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 forecasted for 2026 construction and the cost is estimated at $4.4 million. This cost has been included in the Age-Related Replacement category.

Rebuild of Dakota County 53 - Arkansas Avenue
This project is listed in the Dakota County Transportation plan for 2025 construction. It is typical that projects like this, which are scheduled for construction over a year out, are still being designed by the County. The final scope and impact of the project on the Dakota Electric distribution system is not yet

known. At this stage of a county or city road project, there are typically on-going ROW acquisition activities which can delay projects. $262,000 dollars have been estimated by Dakota Electric based on limited information of how this road rebuild may affect 2.4 miles of existing distribution overhead line. The cost of this project has been placed 100% into the System Project (Driven by Mandate) category.

Appendix E – Table Showing where Commission's Objectives are Discussed in IDP

In the introduction section, a brief summary of how each of the main sections of the Report address the Commission's objectives was provided. Below is a summary of the pages which contain information in support of the Commission's 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	Page #s where information is available
Maintain and Enhance - Safety	56-57,88-89,98,147
Security	48,56-57,89,93-94,98,147
Reliability	1-2,4,8,13-16,17,28,50,63-65,84-85,88-94,123,127,145,147
Resilience	78, 99
Maintaining Costs	4-6,9,10,42-43, 63-85

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

Objective #2 Components	Page #s where information is available
Enable Greater Customer engagement	17-18
Customer empowerment	13-16, 119-122
Options for Energy Services	41-42, 119-122

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;

Objective #3 Components	Page #s where information is available
Create Efficient, cost-effective grid	45, 115-116, 119-122
Accessible grid platforms to support new products and services	7,88-93
Opportunities for adoption of new distributed technologies	33,41-42,88-93

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

Objective #4 Components	Page #s where information is available
Optimized utilization of grid assets	45, 48, 104-108
Minimize total system costs	47, 104-108, 110

Planning Objective #5: 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.

Objective #5 Components	Page #s where information is available
Provide Short-term and Long-term plans	22-28, 31,45,88-93, 101-102, 126-133
Provide Costs and benefits of investments	59-62, 96-99, 126-133
Analysis of rate payer cost and value	*96-99, 133*

Commission Order from Docket: E999/CI-20-800	Page #s where information is available
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.	*43-44*

Commission's September 9, 2022 order, under Docket No. E-111/M-21-728	Page #s where information is available
Required Dakota to file, in its next IDP filing, a thorough discussion of the installation of a utility-operated energy storage system (which would be charged with energy that would otherwise cause back-feeding during the day and that would then discharge that energy in the evening) in light of recent state and federal infrastructure programs. The discussion must include how to calculate cost to benefits impacts and how such storage solutions affect its wholesale power supply contracts and obligations.	*48-49, 53-62*

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-728_M-21-728
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-728_M-21-728
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	Yes	OFF_SL_21-728_M-21-728
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-728_M-21-728
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-728_M-21-728
Craig	Turner	cturner@dakotaelectric.com	Dakota Electric Association	4300 - 220th Street West Farmington, MN 550249583	Electronic Service	No	OFF_SL_21-728_M-21-728