October 31, 2019

Daniel P. Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Subject: ***Dakota Electric Association IDP Compliance Filing***

In the Matter of Distribution System Planning
for Dakota Electric Association
Docket No. E-111/CI-18-255

Dear Mr. Wolf:

On February 20, 2019, the Minnesota Public Utilities Commission (Commission or MPUC) issued an *Order Adopting Integrated Distribution Plan Filing Requirements* (Order) in the above-referenced docket. This Order outlined 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.
>
> 2. Stakeholder Meeting(s): Dakota Electric should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough

to ensure input can be incorporated into the November 1 MNIDP filing as deemed appropriate by the utility.
At a minimum, Dakota Electric should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

3. Filing Requirements: For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter." This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.

Dakota Electric Compliance

Dakota Electric Association® (Dakota Electric® or Cooperative) submits this compliance filing in response to the Commission's February 20 Order in this docket.

Dakota Electric notes that we have previously submitted two informational letters regarding the required stakeholder meeting. Our June 14, 2019 letter included the invitation we sent to potentially interested stakeholders and the draft agenda for the stakeholder meeting. On June 28 we submitted another letter containing the final agenda from the June 25 stakeholder workshop and the presentation material covered during this meeting.

This compliance filing responds to requirements 1 and 3 identified above. Dakota Electric has undertaken a substantial effort (through internal staff and consultants) to prepare this first biennial Integrated Distribution Plan. The attached plan covers the detailed filing requirements outlined in the Commission's February 20 Order.

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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/s/ Douglas R. Larson

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Certificate of Service

I, Cherry Jordan, 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-18-255*

Dated this 31st day of October 2019

/s/ Cherry Jordan

____

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Dakota Electric Association

Integrated Distribution Plan

IDP

November 2019

Provided in response to Minnesota Public Utilities Commission Docket No. E-111/CI-18-255

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Abbreviations and Common Terms

In an effort to assist the reader of Dakota Electric's 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 will install two-way communication meters, meter data management system and load management infrastructure. Additional details can be found in Commission Docket E111/M-17-821.

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

CAIDI: Customer Average Interruption Duration Index. This is a term used by electric utilities to report on the average outage duration that any given 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 a communication system (currently using a paging signal) or start member-owned generation through the use of 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 also includes energy efficiency and Demand Side Management.

DER Generation: For the purpose of 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 energy storage system, typically storing energy through a chemical process, which is normally charged by either the distribution grid or distributed generation sources.

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 utilities Demand-side Management system.

Non-wires Solutions (NWS): Also referred to as non-wires alternative. This is a type of solution to use on the distribution system 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

Request for Information (RFI): A document sent to various vendors by Dakota Electric requesting information about potential non-wired solutions for specific issues. RFI responses normally provide generalities with regards to costs.

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.

Transactive Energy: Refers to a system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.

Introduction

This Integrated Distribution Planning (IDP) report was created in response to an order from the Minnesota Public Utilities Commission (Commission) in Docket No. E002/CI-18-255. This report is organized following the sequence provided by the Commission order. The format is the Commission question or request for information, followed by the information or response.

Dakota Electric Association's (Dakota Electric) approach and philosophy with responding to the questions contained within the Commission's IDP order was 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 understand the issues. Given one of the Commission's stated objectives was to move towards new products, services and opportunities for DER integration, Dakota Electric has reached out to DER vendors in an attempt to identify non-wired solutions which could be utilized by Dakota Electric as part of the IDP process. Dakota Electric has worked to be responsive to the questions and issues raised within the Commission's final order.

Included within the conclusions section of the Dakota Electric IDP report are comments about the arduous undertakings that was involved with the development of this IDP report by Dakota Electric and suggestions to be considered for future IDP reports.

1. Integrated Distribution Planning

The intent of this IDP report is to provide more transparency into the distribution planning process. In addition, this provides an educational platform to allow others to learn how Dakota Electric performs distribution planning and provides an 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.

From the Minnesota Public Utilities Commission order creating the IDP reporting requirements, the Commission wrote;

> ***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 ratepayer cost and value.*

From Dakota Electric's perspective, much of the IDP report order focuses on capital spending and the research into the use of non-wires solutions (NWS). The general question being asked is whether Dakota Electric is properly evaluating NWS during the distribution planning process. This IDP report seeks to answer this question.

Coupled with the consideration and use of NWS, the Commission ordered Dakota Electric to present the report to a group of stakeholders and work to incorporate their information within the final report. As part of the IDP report, information which has already been collected from the members about their beliefs and needs, is included. In addition, in response to the IDP report requirements, Dakota Electric completed additional outreach to the residential and commercial members. The results of that outreach are also included in this report.

Given the overall content of the order for the IDP report and the focus on non-wired solutions, Dakota Electric gave additional consideration of this portion of the Commission's request. In addition to presenting information to a group of stakeholders to gather their feedback, Dakota Electric has also reached out to DER vendors to gather information about potential NWS through a Request for Information (RFI) process. To accomplish this, Dakota Electric, with cooperation from STAR Energy Services LLC and the Center for Energy and Environment, created an RFI, which was designed to gather high-level information about potential non-wired solutions to common distribution planning issues. The RFI document and the results of that RFI process are included in this report.

Dakota Electric would like to thank STAR Energy Services LLC (STAR Energy) and the Center for Energy and Environment (CEE) for their assistance with this report. To help Dakota Electric complete this report, STAR Energy of Alexandria, Minnesota was engaged and assisted with the report writing, analysis and coordinated the stakeholder RFI process. To help provide non-utility insight and ideas, CEE was engaged for the IDP report and process. CEE not only helped provide a non-utility perspective throughout the process but also facilitated the face-to-face stakeholder discussions.

Dakota Electric would also like to thank the vendors who responded to the stakeholder RFI. Those vendors who chose to respond did so without any compensation and provided Dakota Electric with actionable information for this report.

2. Background Information

Dakota Electric Association is a not-for-profit electrical cooperative, serving the electrical needs for over 108,000 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 Scott, Goodhue and Dakota Counties.

Figure 1. Dakota Electric's Service Territory.

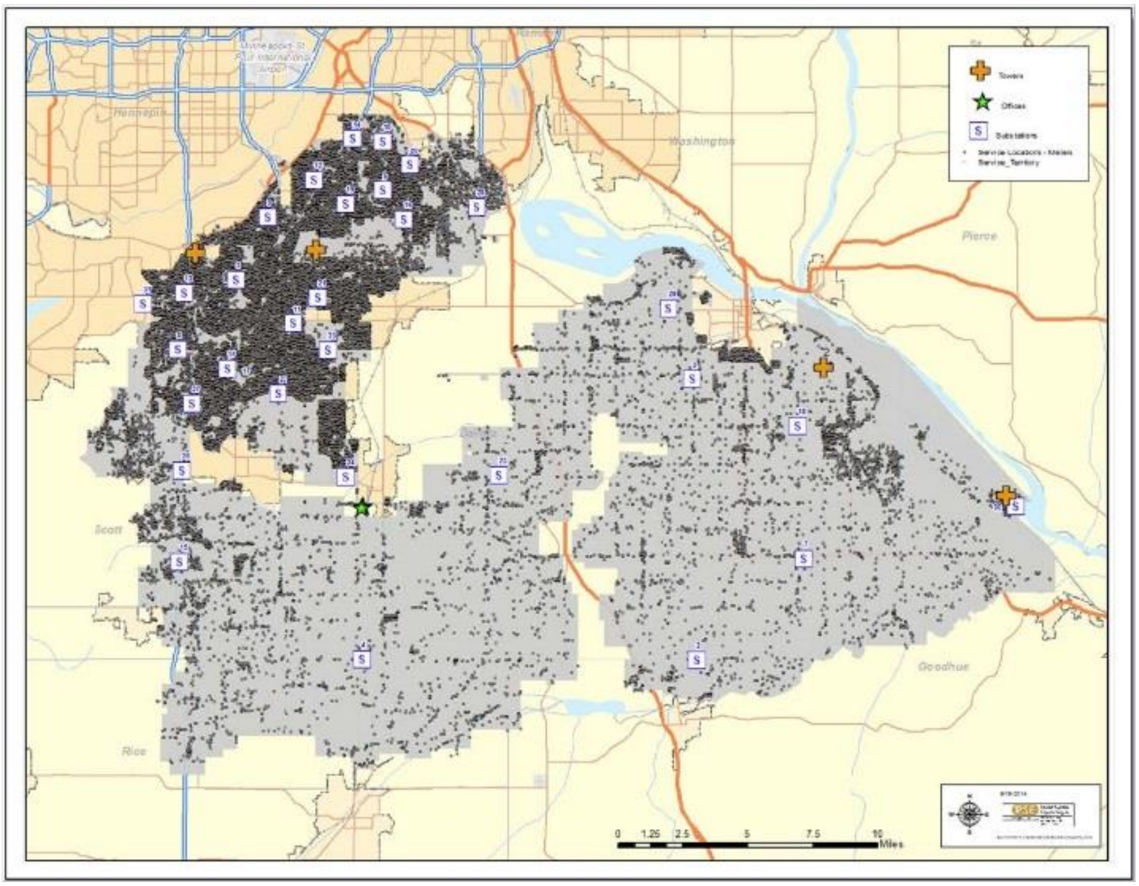


Figure 1 shows the Dakota Electric service territory. The 500 square mile service territory is mostly within Dakota County, Minnesota. Each of the small black dots represents member services and the boxes with the letter "S" are the distribution substations. These substations provide the connection between the transmission grid and the Dakota Electric's distribution system. The green star near the middle of the figure is Dakota Electric headquarters located in Farmington, Minnesota.

As shown by the figure, most of the electric services are in the northern suburban portion of Dakota County. This 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 in nature.

As a not-for-profit, member-owned cooperative, Dakota Electric is focused on providing safe, reliable, economical electrical energy to our members. Member-owned and member-focused is in the promise of the 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 25 largest electric distribution cooperatives in the nation. Dakota Electric is also the only electric cooperative utility, rate regulated by the Public Utilities Commission in Minnesota.

Dakota Electric purchases wholesale power from Great River Energy, a generation and transmission cooperative, that is headquartered in Maple Grove, Minnesota. The Dakota Electric distribution peak demand has been between 450-500 MW and occurs in the summer months. This peak electrical demand is driven mainly by air conditioning of homes and businesses.

In the 1970's, the Minnesota Legislature determined that the orderly development of economical statewide electric service required granting electric utilities exclusive service rights within designated service areas. 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' <u>requirement-to-serve</u>.

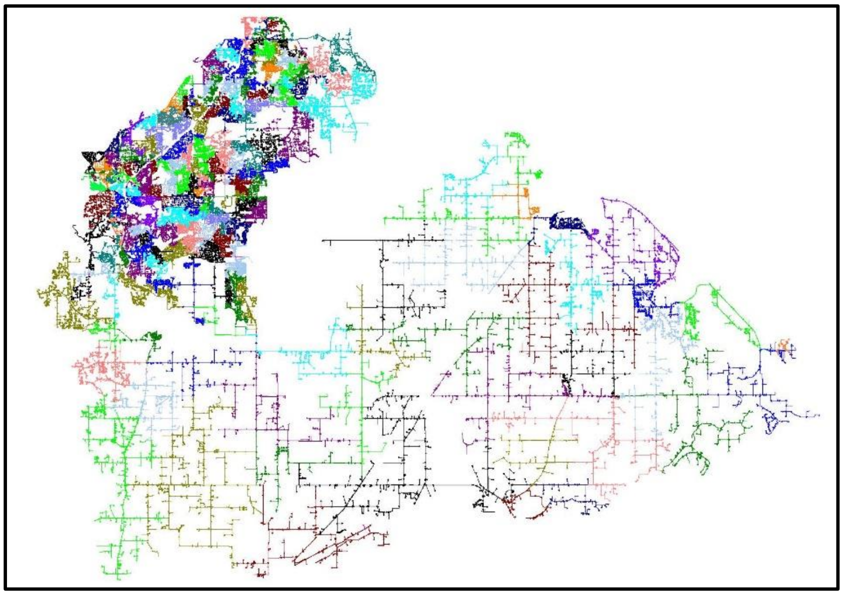
While each electric utility has individual requirements and processes for connecting new electrical services, they all have a requirement-to-serve. This requirement-to-serve includes the installation and maintenance of distribution facilities with enough capacity to supply the electric needs of customers within their assigned service territory.

The requirement-to-serve drives the utilities to ensure that they not only have sufficient facilities to meet the expected electrical demands of the 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. Electrical outages due to not planning and/or building enough facilities would not be acceptable to the consumers. The risk of not being able to reliably serve the consumer's electrical requirements is a key issue with incorporating non-wires solutions.

Over the years since Dakota Electric was established, the cooperative has developed an extensive electrical system. Figure 2 is a screen shot from Dakota Electric's Milsoft Windmill®

engineering model showing the distribution system. Each of the lines represent a piece of the primary distribution system (wires and cables). Each of the colors represent the electrical wires associated with a feeder.

Figure 2. Circuits in the Engineering Model



3. Reliability

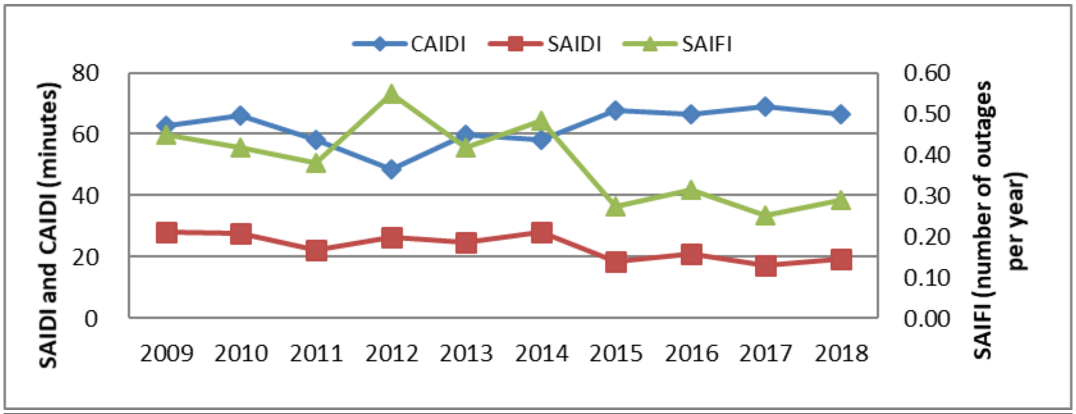
Coupled with the requirement-to-serve, the reliability of the electric supply is equally as important to the members. The reliability of the electric service supplied by Dakota Electric ranks as one of the most reliable electric utilities in the United States. When comparing Dakota Electric's reliability key indices with other utilities, few perform better. Table 1, below is from the most recent annual Service Reliability and Service Quality (SRSQ) report filed with the Commission. Graph 1, on the following page, is a historical look at Dakota Electric's reliability indices.

Table 1. 2018 Reliability Indices

Index	2018 Performance Goal	2018 Actual Performance	5-Year Average (2014-2018)	2019 Performance Goal
CAIDI	**64.3 minutes**	66.7 minutes	65.6 minutes	**65.6 minutes**
SAIDI	**21.9 minutes**	19.3 minutes	20.8 minutes	**20.8 minutes**
SAIFI	**0.35**	0.29	0.32	**0.32**

Annual Reliability Indices for Dakota Electric (Excluding Major Event Days)

Graph 1. Historic Reliability Indices



4. Demand-side Management

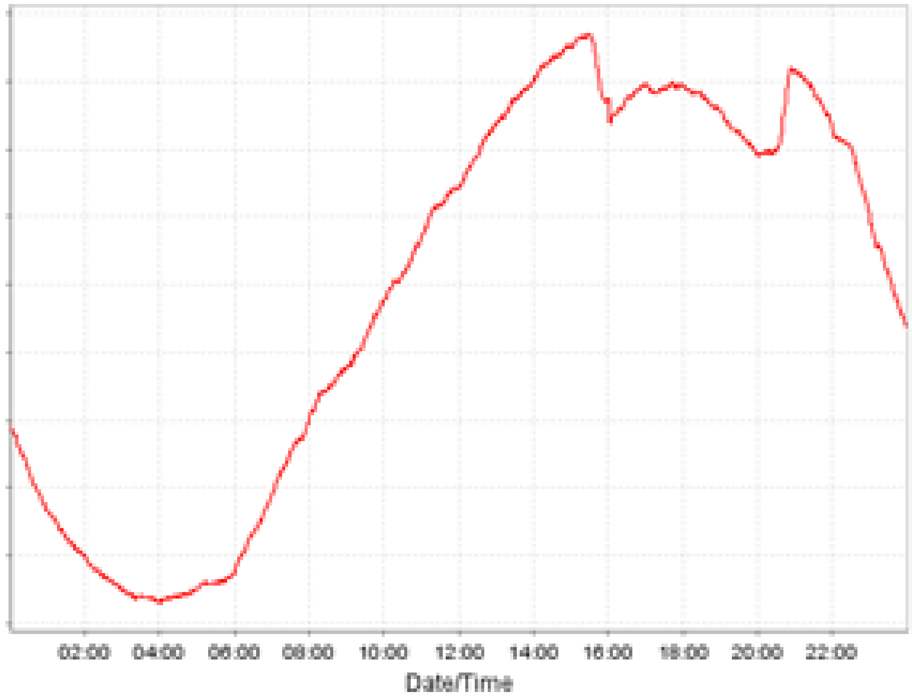
Dakota Electric has an extensive demand-side management system and can shed around 100 megawatts during summer months and 70 megawatts during winter months. Without the demand-side management system the system peak electrical demand would be much greater.

The demand-side management system includes over 50,000 air conditioners and heat-pumps, over 7,000 water heaters and various other loads under control by the demand-side management system. Dakota Electric also has an interruptible rate for the commercial members where many members have installed full capacity generation. During peak load events or system emergencies they are able to transfer all of 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 the members to create many 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.

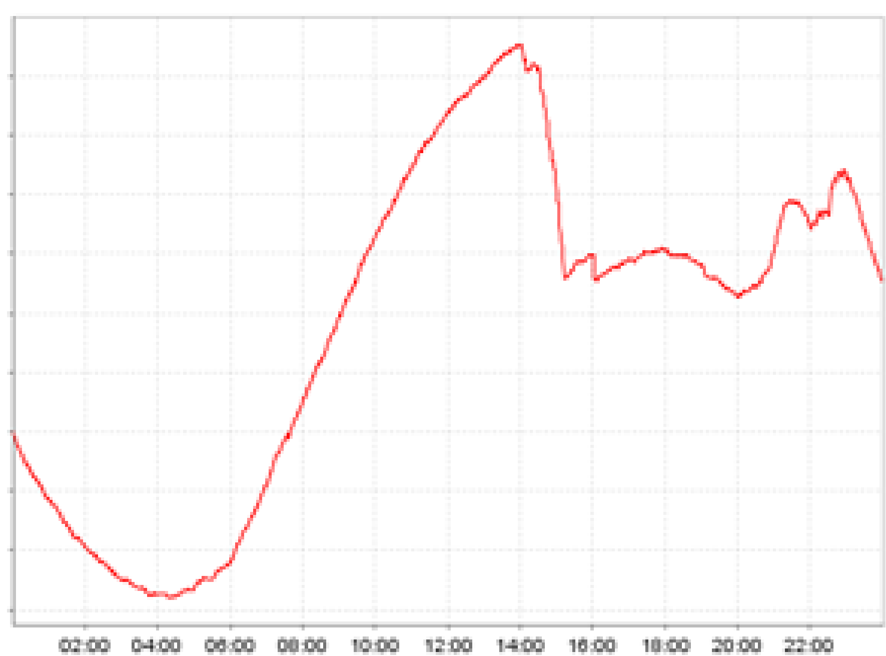
Through the demand-side management system Dakota Electric has a very significant amount of load which can be controlled. Dakota Electric is unique among utilities with the ability to control a large percentage (20-25%) of total system demand. Within the IDP report the demand-side management system may also be referred to as the demand response or load management system.

The following graphs are some typical summer peak load curves with load management controlling the peak loads. Notice the significant differences between the two curves. 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.

Graph 2. Example A - Summer Peak Day with Load Management



Graph 3. Example B - Summer Peak Day with Load Management



Dakota Electric has over 100 MW of demand which can be controlled on a hot summer day. The load control consists of AC units, water heaters, irrigation and other heating devices such as heaters and hot tubs. In addition, some of the businesses have full capacity generation which can disconnect the entire load of the business or the entire campus and carry that load on their generation system.

Dakota Electric, in coordination with Great River Energy, Dakota Electric's power supplier, operate the load management system to reduce Dakota Electric's electrical peak demands when Great River Energy's peak demand is the greatest. 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 membership millions of dollars in wholesale power costs each year.

The next section explains how the peak electrical demands on the feeders and substations are developed and used for distribution planning. It is important to understand that those peak demand values incorporate reductions provided through the use of the demand-side management system.

<u>Peak Electrical Demands</u>

Much of Dakota Electric's capital construction budget is driven by the peak electrical demands of the member loads. Dakota Electric must maintain enough electrical distribution facilities to supply the peak demands of the membership, every second of every day. If there is an event, including storms or normal equipment failures, the members are expecting Dakota Electric to be able to quickly restore electrical supply to their home or business.

Forecasting the electrical demands for the individual distribution transformers which supply each of the services, all the way up to the demands on the main circuits and substations, is very important. While it would be easy to over forecast capacity needs, that would result in excess capacity and increased costs for the members. On the other hand, under forecasting will lead to overloaded equipment, equipment failures and outages for the members. Forecasting is a process of balancing between spending too much or accepting too much risk.

Dakota Electric has Supervisory Control and Data Acquisition (SCADA) monitoring and control at all of the substations including monitoring each of the substation feeders. SCADA provides remote control and real-time data about the voltage and power flows on the different distribution system elements. Outside of the distribution substation fence, Dakota Electric has limited SCADA capability.

To develop the peak loading on the substation and feeders, historical loading levels are captured by the SCADA system and used to create a forecast of the peak loading for each of the feeders. The forecasting process is manually done by looking at each of the feeders' load levels during several historical peak days. The historical peak numbers must be screened to eliminate maintenance, construction and emergency peaks which have occurred due to load being temporarily moved between feeders.

5. Annual Construction Capital Budget Development

Many of the questions put forth for the IDP report focus on Dakota Electric decisions for projects to be completed each year. The following is an explanation of the overall planning and decision process used by Dakota Electric for capital construction projects.

Each year, as part of the annual budget cycle, individual capital construction projects are identified. The capital construction budget includes any construction of distribution facilities. This may be distribution substations, feeders, residential and commercial developments, rebuilding of distribution lines in support of road construction, rebuilding of electrical service to member's homes and replacement of equipment such as switches, poles and transformers. The capital construction budget does not include expense spending for maintenance and operational items such as tree trimming, underground locating service, power quality investigation or outage restoration.

The development of the annual capital construction budget starts in early September with the development of an engineering model of the existing distribution system. The engineering model is based upon a data extraction from the Graphical Information System (GIS) which contains the electrical wire connectivity information and billing data reflecting the members monthly electrical usage.

For each of the feeders, (the main circuits coming out of the distribution substations), maximum expected electrical load levels for the coming year are developed for the model. This is done based upon the past year and recent prior years historical maximum loads for each of the feeders. Using the historical values and expected growth for each of the feeders, the maximum expected feeder and substation demands for the coming year are developed. These estimated maximum feeder demand values are then combined with the existing member metered load values within the base engineering model to "allocate" the maximum demands across each of the feeders within the model. The result is an engineering model of the existing electrical configuration, but with the loads distributed along each of the feeders to represent levels reflective of the next year's forecasted load levels.

At the same time the base engineering model is being created, Dakota Electric employees are contacting the cities and counties to acquire information about possible road reconstruction projects, which may require the existing distribution wires and underground cables to be moved and/or replaced. During those discussions and throughout the year, Dakota Electric also learns about potential larger residential and commercial developments which could be filed by developers and approved for construction during the following year. Information about these larger proposed residential and commercial developments are incorporated within the maximum feeder forecasted demands, to ensure there is enough feeder capacity to supply the new developments as homes and businesses are built. A large percentage of the annual capital budget is driven by local construction requirements. Depending upon the year, 40-75% of the distribution capital budget is in response to requests for new electric supply and governmental projects.

All of these required projects are estimated and added to the initial capital construction budget. It is important to understand that no detailed design for these projects is created at this point, therefore the project estimates are high-level estimates with a large margin for error. Required projects, such as road reconstruction and new developments, typically are not yet fully designed and the impact to existing Dakota Electric facilities can only be estimated. There is also a reasonable chance that the required project may be canceled and or the scope of the project may be modified. The actual impact of a road reconstruction or new development project is not known until some point in the following year. For example, Dakota Electric is notified of the confirmation that a road reconstruction is going ahead as the project is released for bidding by the road contractors. The lead time of notice to Dakota Electric before these types of required projects begin actual construction is often less than a few months. The time available for Dakota Electric to design and order necessary distribution material is normally very short in duration. Hence, high-level estimates are normally used for these types of required projects in developing the initial capital construction budget.

Next, the model of the distribution system, with the existing electrical configuration and existing service connections, but with the load scaled to reflect the estimated demands for the following year, is studied to identify voltage, capacity and other issues which must be resolved. For each of the identified issues, a potential solution is developed and budgeted. Potential solutions could be as simple as adding a capacitor to help raise the voltage in an area. Or potential solutions could involve a larger project to rebuild a section of a feeder.

By early October, Dakota Electric has developed the annual capital budget with all of the known required projects and all of the projects required to support any growth in electrical demands. During October, other capital construction budget categories are forecasted using historical data. Categories forecasted by historical data are reactionary in nature as the individual projects within those categories are triggered by the members or replacement of equipment that fails during the year. These historically forecasted categories include:

- <u>Miscellaneous Distribution Equipment</u>: this includes street lighting that is not part of new developments, capacitors, regulators, sectionalizing equipment, and overhead and pad-mounted switches.
- <u>Service Rebuilds</u>: includes conversion of members electrical service from overhead wires to underground cables and is requested by the members during the year.
- <u>Pole Replacements</u>: These are triggered by Dakota Electric’s annual pole inspection where around 10% of the system’s poles are physically inspected. Poles that fail the testing are replaced within the year the testing occurred.

Additional projects that are next added into the initial capital construction budget are project categories that are provided by individuals and groups within Dakota Electric, based upon their reviews of the issues involved. These project categories include:

- New residential and commercial services (wires, meters, street lights etc.) The number of new residential and commercial services is forecasted for the next year along with the estimated costs to interconnect those services.
- Underground cable replacement
- Transformer replacements
- Substations

The underground cable and transformer replacement categories are dependent upon past failure rates and may include dollars for special initiatives put forth by Dakota Electric. An example of a past special initiative project was replacing all unjacketed and less reliable cables which provide service to critical services, such as hospitals, police and fire stations.

The substation category is the one category which needs to be planned a few years in advance as the lead time for permitting and construction is longer than one year. While substations are planned for multiple years prior to construction, the actual timeline of the substation project is adjusted each year based upon actual and forecasted load growth on each of the substations.

Parallel to this process to develop an initial capital construction budget is an internal Project Charter process where larger new initiative projects are being presented and reviewed by senior management. In most cases, charter projects do not impact the capital construction budget, for example, replacing the roof on the headquarters building or upgrading the accounting software systems. However, a charter project like Dakota Electric's AGi project, does affect the capital construction budget. In this case the dollars for an authorized charter project are also included in the initial capital construction budget.

By the middle of October Dakota Electric has a draft capital construction budget with estimated dollars for each of the categories. The draft capital construction budget is then reviewed for ways to reduce or delay capital expenses prior to presenting the capital construction budget to the senior management at Dakota Electric for another round of review, adjustments and approval. In November, upon senior management's approval, the final version of the capital construction budget is presented to the Dakota Electric board for a final round of review, adjustments and approval.

The capital construction budget is only looking forward for one year. Only a one-year budget with specific projects is possible, due to the reactionary nature of the distribution utility business. This is because individuals and developers do not inform Dakota Electric of their building plans that will occur multiple years in the future. Also, cities and counties do not commit to a firm time table for roads that will be added or reconstructed. In addition, site specific changes to the distribution system, such as additions of new solar, energy storage systems or electric vehicles are unknown to Dakota Electric even during the annual capital construction budget process. Distribution planning can develop a framework for longer term changes to the distribution system, however the actual construction of electrical infrastructure must wait until it is required and is incorporated in the annual capital construction budget.

6. Stakeholder Engagement

As part of the IDP report development, the Commission asked Dakota Electric to engage with its stakeholders. As a cooperative utility and a not-for-profit corporation, Dakota Electric has a different framework for defining and engaging with stakeholders than perhaps an Investor-Owned Utility. Dakota Electric is governed by a Board made up of members, which is elected by the membership. This provides direct and immediate feedback for the staff from the membership. It is also a part of Dakota Electric's normal business practice to communicate with the members. This two-way communication between the membership and Dakota Electric results with Dakota Electric being naturally and consciously responsive to the members.

Within the IDP report, Dakota Electric will explain how the Cooperative normally engages with the membership. Dakota Electric has also undertaken additional outreach with stakeholders (members) to gather their insights on specific topics related to the IDP.

Furthermore, specifically for the IDP report, Dakota Electric took additional steps to engage with other parties that were not necessarily a part of the membership which are referred to as "external stakeholders" in this report. The following sections summarize the information gathered in the normal stakeholder interactions and information gathered through the special IDP outreach initiatives.

7. Existing Member Surveys

Dakota Electric completes a formal member survey every other year. The last residential survey was competed in 2018 and the last commercial survey was completed in 2017. Both surveys included a section on renewable energy with the goal to better understand the memberships' opinions toward renewable energy. These surveys results reflect the members' attitudes towards renewable energy, energy conservation and personally installing solar panels on their homes and businesses.

From the survey Dakota Electric has found that the membership has a diverse set of beliefs. Identifying how Dakota Electric can best be responsive to all the needs of all members is one of the challenges for the Cooperative. Just over half of the residential membership responded in the surveys that it is important for the Cooperative to offer renewable energy. However, in the last survey nearly one-third of the residential members responded they do not want to pay more for renewable energy, while two-thirds of respondents stated they are willing to pay something extra for renewable energy. To add to the complexity of the survey results, over 80% of the residential members informed Dakota Electric they do not want to pay in excess of 10% more for renewable energy. One interesting fact of the residential membership is there was no significant difference between age groups willing to pay more for renewable energy.

The majority of commercial members hesitate paying more for renewable energy, although the numbers of commercial members willing to pay more has slightly increased over prior surveys.

Looking at the survey results and seeing that most of Dakota Electric's commercial members and at least one-thirds of the residential membership does not want to pay more for renewable energy, but two-third of the residential membership would pay up to 5-10% more, creates quite a dilemma for Dakota Electric. When first faced with this dilemma in the mid 1990's, Dakota Electric decided to provide the option to the membership to choose renewable energy if desired.

In the mid 1990's, Dakota Electric, along with Cooperative Power, (the power supplier for Dakota Electric at the time prior to the formation of Great River Energy), became the second utility in the nation to provide the option for the membership to select renewable wind power for their home or business. The Wellspring Renewable Energy program, where members can choose to obtain power from wind turbines, was developed providing a choice of energy source for the membership. Since then, electrical energy from solar systems has also been added as an option for the membership. With these programs, the member can sign up for some or all of their electrical needs to be supplied by renewable resources. The great feature of these programs is there is no need for the members to pay high upfront costs to install their own renewable systems nor is there a required commitment to a long-term agreement. The members are free to join or leave the program with little notice.

When residential members are asked about installing solar panels on their home, nearly 40% of them definitely would or probably would install solar on their home. This percentage has been continually increasing over the years the residential surveys have been collected. For the commercial membership, few commercial accounts are planning on installing solar systems at their business in the next couple of years.

8. IDP Stakeholder Outreach

Dakota Electric held a stakeholder workshop on June 24, 2019 to present preliminary findings of the IDP. The three primary meeting objectives were to:

- Introduce Stakeholders to Dakota Electric's business model and approach to distribution planning;
- Educate stakeholders on the existing distribution system, load management, including DERs; and
- Solicit stakeholder feedback of draft content of Dakota Electric's 2019 IDP.

Stakeholders attended from the following organizations:

- Citizens Utility Board of Minnesota
- City of Eagan
- City of Rosemount
- City of Lakeville
- Clean Energy Economy Minnesota
- Dakota County Department of Transportation
- Fresh Energy
- Great River Energy
- Kandiyo Consulting
- Minnesota Power
- Minnesota Public Utilities Commission
- Minnesota Rural Electric Association
- Office of the Attorney General
- Otter Tail Power Company
- Xcel Energy

The following organizations where invited but were unable to attend.

- Interstate Renewable Energy Council
- Minnesota Center for Environmental Advocacy
- Great Plains Institute
- Minnesota Department of Commerce
- City of Apple Valley
- City of Hastings
- City of Farmington
- City of Burnsville
- City of Inver Grove Heights
- Scott County

Presentations covered background information on Dakota Electric's business model, existing load management programs, trends in electric vehicles and distributed solar, the current process for distribution planning, and current capital spending. Presenters then reviewed in more depth two components of the IDP: the analysis approach and results for testing maximum DER penetration on Dakota Electric's system, and the Request for Information results for non-wires solutions projects. The meeting agenda and final presentation materials were filed as part of this docket on June 28, 2019.

Stakeholder feedback during and after the meeting was supportive of the approach and level of detail provided. Stakeholders were asked to submit comments on areas where they would like to see additional information in future IDPs. Themes of these comments included discussion of how Dakota Electric is integrating national best practices in their approach (especially for non-wires solution), encouragement to continue coordinating on infrastructure planning and DER adoption with local governments, and additional detail on Dakota Electric's predictions for load growth from electrification.

The meeting was facilitated by the Center for Energy and Environment.

9. IDP Survey

As part of the IDP process, Dakota Electric decided to complete additional outreach to the residential and commercial members. Working together, CEE, Dakota Electric and STAR Energy created a basic residential and commercial survey to use when reaching out to the Dakota Electric membership.

Dakota Electric hosts an annual night at the zoo, with free admission for members, to the Minnesota Zoo. At this event, Dakota Electric has tables set up to provides information about load management options and other programs offered by Dakota Electric. This year an additional was arranged to request information from the members about their opinions towards renewable energy. As incentive to complete the renewable survey, members were entered into a drawing for a coffee maker. Some of the members who were asked to take the renewable energy survey stated that they were not interested in renewable energy and walked away without filling out a survey. Because of this, the results of this survey done during the Zoo event, are non-scientific and may not provide an accurate picture, respective of the membership as a whole. But, given this disclaimer, the results of this survey do align with what Dakota Electric has been hearing from the membership in general. Survey results can be seen in *Appendix F – Residential and Commercial IDP* Survey.

Section A. Baseline Distribution System and Financial Data

1. System Data: Modeling Software

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

Dakota Electric is using the Milsoft Windmill® software for modeling the distribution system. Dakota Electric maintains the real-time and normal system connectivity and equipment information within an ESRI based Graphical Information System (GIS), which includes the Outage Management System (OMS). The OMS is the software which is used to maintain the 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 a study model to be used with the Milsoft Windmill® software.

Dakota Electric has no immediate plans to replace the Milsoft Windmill® software or to implement other planning software since the Milsoft Windmill® software meets the present needs. Dakota Electric continues to research information with vendors and other utilities to learn what new capabilities are available. Dakota Electric is keeping an eye on Advanced Distribution Management Software (ADMS) and believes that in the future, with higher penetration levels of DER, there will be a need to implement this type of software to support the operation of the distribution system. Currently Dakota Electric's focus is on implementing the Advanced Grid Infrastructure (AGi) project equipment and the associated software. Any decision to purchase and install an ADMS system will be done after the completion of the AGi project.

2. 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 to be built will also be equipped with SCADA monitoring and control. All feeders have digital protective relaying and are monitored at the substation by the SCADA system. Dakota Electric is presently adding SCADA monitoring and control to some of the downline regulators and key remote switches that are installed away from the substation and located on the feeders. DER that is part of the C&I Interruptible – Rate 70, also has SCADA monitoring and controlled installed by Dakota Electric. There are presently more than 125 of these member-owned generation systems on the C&I Interruptible – Rate 70. Also, there are a few larger DER installations which are monitored and the SCADA control system has the ability to remotely curtail or disconnect the DER from the Dakota Electric system.

3. 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 the 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. 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.

Presently, once the feeder leaves the substation, the real-time monitoring and visibility is limited. There are several places where a voltage regulator or a remote operated switch has SCADA monitoring installed, but most of the distribution system is presently not monitored in near-real time. Dakota Electric would estimate at present, less than 10% of the feeders have some type of SCADA monitoring of the downline feeder devices.

Dakota Electric does have some limited monitoring at a member's service where members are participating in the C&I Interruptible – Rate 70 demand response / load management program. These members have installed generation which is remotely controlled by Dakota Electric to take their entire load off the distribution system during peak demand periods. For members which are on this C&I Interruptible rate, Dakota Electric has installed SCADA monitoring and control on the generation system to ensure the reliable operation of the generation. This provides Dakota Electric with some limited visibility at their service. For these services, the members electrical usage is recorded every 15-minutes within the meter and that data is periodically uploaded to Dakota Electric.

At present, Dakota Electric reads each of the member's meters monthly through the traditional meter reading process. Through this process, the monthly energy usage for each of the members home or business is recorded.

As has been reported to the Commission, Dakota Electric is in the middle of a major project to replace all the existing meters with 2-way communicating AMI meters. The implementation of the Advanced Grid Infrastructure (AGi) project will greatly enhance the visibility at each of the members services. The AGi project includes replacement of the existing metering and load control infrastructure. The AGi two-way communication meter will be programmed to record the members electrical usage every 15 minutes and send that information back to Dakota

Electric every 4 hours. The meters will also provide information about average, minimum and maximum voltages during each of the 15 minutes periods.

4. 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.

Dakota Electric has over 5,000 "Turtle" AMR meters which can provide periodic energy and demand readings back to the Dakota Electric office. This system was installed in the 1990's and is an aging system with a high rate of failure. All the Turtle meters will be replaced as part of the new AGi project. The new AGi meters will provide 15-minute energy values from all the meters. In addition, the new meters will provide voltage and general power quality monitoring for all members. Any member who chooses to opt-out of the AGi meter installation will not have voltage and general power quality monitoring. Nor will their meter automatically report power outages back to the Dakota Electric headquarters.

5. System Data: Coordination of System Planning

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

<u>Planning Process</u>

Dakota Electric works closely with Great River Energy in many aspects of the planning and operation of the electrical systems. Great River Energy organizes and supports committees and groups which include both Great River Energy employees and employees of the member distribution cooperatives. These groups provide education, coordination and communication between the organizations.

Engineers from each of the organizations are involved during the planning process to create Long-Range Transmission or Long-Range Distribution studies. The reports are shared between Great River Energy and Dakota Electric for review before plans are finalized. When new distribution substations are proposed by the member distribution cooperative, Great River Energy is involved to review the proposal and together Great River and the Cooperative look at the possible options before any plans are finalized. Great River Energy contacts the Cooperatives during the transmission planning process to review any transmission issues within that Cooperative's service territory and together possible solutions are discussed. As part of this review process, often other possible solutions to the identified transmission issues are discussed, including potential non-wired solutions. When a transmission modification or addition is selected, the Cooperative is involved in the design and permitting process as needed.

Demand Management / Load Management / Energy Efficiency
Great River Energy works closely with all its member distribution cooperatives to implement demand management / load management of the distribution loads. In addition to this effort Great River Energy provides support and coordination for many different energy efficiency programs.

Many of the load management programs offered by Dakota Electric would not be possible without the support and coordination of Great River Energy and its member cooperatives. In Great River Energy's 2018 IRP report, Great River Energy voiced continued support for demand response activities. Together Great River Energy and the member distribution cooperatives continue to look for ways to improve the benefits derived from demand response programs.

In addition to demand response programs, Great River Energy has a large portfolio of energy efficiency programs. The energy efficiency programs have been created through joint development with the distribution cooperatives and with the members. Both the demand response and the energy efficiency programs are saving Dakota Electric's members millions of dollars in energy and power costs annually.

6. 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 Great River Energy, completes a long-range load forecast every two years and that forecast looks beyond the next 10 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 of DER penetration and generation levels are naturally included using the historical monthly and annual energy usage by member category for the forecast. Some manual adjustment of the long-range energy forecast was done to reflect the expected increasing penetration of DER.

For short-range load forecasting, Dakota Electric is looking one year into the future and using the prior year's peak feeder and substation loads. The prior year's actual peak demands include reduction of the potential peak demands through the operation of the demand response system. Presently Dakota Electric's peak demands are occurring during the hottest days of the summer. Depending upon the area supplied by the feeder, the time of day for the peak will be different, but currently all feeders experience their peak demand during the summer months. Each fall, Dakota Electric reviews feeder loadings for the prior summer season and develops a forecasted peak loading for the next summer. The potential for new loads that may be added to an individual feeder are included in that feeder's forecasted peak loading.

Dakota Electric does not receive advanced notice of DER generation being added to a feeder, so new DER additions are not included in the annual feeder and substation load forecasts. Since most of Dakota Electric's feeders peak around 6-7 pm in the summer, the addition of new DER generation has not been affecting the summer peak demand levels. With greater penetration of DER integration, the need to forecast and understand the DER effect on feeder peak loading will be important.

Dakota Electric is currently researching how to forecast larger DER generation on the feeders. As Dakota Electric does not control or maintain the DER generation units, there is a possibility that the DER could not be on-line during one or more of the summer peaks. With more DER generation being added to the distribution system, the possibility is increasing that multiple units will be experiencing an outage, due to storm damage (hail or high winds) or multiple equipment failures, over a summer peak day. Currently, since the DER generation systems do not greatly impact the peak feeder demands, the feeder is sized to support the feeder load in the event the DER generation fails to operate as normal. With the addition of energy storage, Dakota Electric will need to develop study methods and planning standards to help properly study and manage the risk of a DER failure.

Dakota Electric has a large portion of peak load which is managed by the load management system. Because of this, Dakota Electric needs to include the operation of load management within the feeder load forecasting process. As Dakota Electric uses the prior year peak summer loads as the starting point for the substation and feeder load forecast, the operation of load management is naturally included within those historical numbers. A typical load control day starts the load control around 2 pm and continues until 8 or 9 pm. The load control, in effect, is reducing the normal feeder peak load which is typically occurring around 6 pm. Because of this reduction in feeder peak demands due to load control, the actual feeder peak occurs on days without load control or, most commonly, just before the load control starts on a peak day. For example, if the load control starts at 2 pm on a peak day, for most of the feeders the load between 1:30 and 2 pm is when the historical feeder peak tends to occur. For feeders which supply large data centers or other industrial users which have a flat usage pattern, the 1-2pm peak is very similar to what the peak load on that feeder would have been without load control. For these industrial feeders the DER load management has little effect upon the forecasted peak load.

For the rest of the feeders the potential feeder peak is reduced by the operation of DER load management. The actual peak (reduced by load management) is used as the basis for the forecasted feeder peaks. If the Dakota Electric load management system would fail to operate over any peak summer day, the actual peak load could be greater than the forecasted value for some of the feeders. Because of this concern, Dakota Electric uses multiple methods to control the members' load management systems. Within those control systems, backup methods are available. Dakota Electric's load management is accomplished using two separate systems; one is using the SCADA system to control the member-owned generation units and the other uses a commercial pager system to trigger the load control receivers to shed their loads. Dakota Electric has purchased, permitted and installed a second pager system to control the load control receivers in the event of a commercial pager system failure.

7. 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 with the new IEEE Standard 1547-2018. With the variable nature of the DER generation, the energy output cannot be counted upon to be available 100% of the time to offset the individual members electrical demand. Once the overall level of DER penetration increases, the aggerate output from many DER generators may provide a 100% reliable reduction in electrical demand at a substation level. But since Dakota Electric does not control the installation timing and placement of DER generation, the planning process would need to be in reaction to existing DER generation.

A significant issue with inverter based DER generation is the loss of energy production immediately upon restoration of power after an extended outage. The IEEE Standard 1547-2018 for return to service (Enter Service) has a delay time where the DER is prohibited from interconnection with and generating energy into the distribution system after a prolonged outage. After a prolonged electrical outage, upon reenergization, the electrical demand is naturally greater than before the outage occurred. This is called "cold-load pickup". There are two main drivers for this increase in electrical demand. The initial driver for cold-load pickup demand is from the energization of motors and transformers. The energy inrush required to magnetize the cores of these devices causes a surge in electrical demand. This is only for a very short time frame and is well understood and will not be increased by inverter-based generation. The second driver for inrush has been loss of diversity of the electrical loads. This is caused by most of the electrical units, such as water heaters, electrical heaters, air conditioning units, running at the same time, to make up for the heating or cooling which wasn't done during the electrical outage. This loss of diversity causes the electrical demand to increase over the existing demand levels going into the outages. The longer the outage lasts the greater the cold-load pickup is and the longer this effect lasts. The design of the electrical system must take this into account when sizing the capacity of the electrical equipment, especially the very fast-acting protective equipment, like fuses and relays.

During electrical outages on the distribution systems, many consumers believe that the DER is capability of supplying the household electrical requirements. Most DER systems which are presently being installed shut down during distribution system outages and do not provide outage back-up protection for the consumer.

With the installation and interconnection of inverter-based DER generation, the normal or typical peak load experienced by the distribution system could be reduced by the DER generation. Upon restoration of the distribution system from an electrical outage, the inverter-based DER is not generating electricity to off-set the electrical load of the member's home or business. All the household or business electrical demand would be placed on top of the traditional cold-load pickup demand and will greatly increase the demand during restoration of the distribution system. If the distribution system, especially the protective elements, was built to accommodate just the pre-outage peak electrical demands experienced during normal operation and did not account for the electrical demands which can occur after an extended outage, subsequent outages, resulting from overloading the distribution system during restoration will occur.

Incorporating energy storage system, of sufficient size and capacity, along with the installation of DER could help reduce the level of increased demand being placed upon the distribution system as the result of short to medium duration electrical outages. The problem would still exist for longer duration electrical outages where the capacity of the energy storage system to ride through the electrical outage could be exhausted.

Dakota Electric plans on utilizing production meters on DER generation to allow Dakota Electric to have visibility of the actual member peak electrical demand which could be placed on the distribution system after an electrical outage. Through the use of the 15-minute interval data from the main service meter and the production meter, Dakota Electric will be able to calculate the potential peak demand, coincident with the feeders' peak demand. Dakota Electric will then also be able to understand the coincidence between each of the services' demands. This will help reduce the need to build in extra capacity into the distribution system to meet demands which are actually non-coincidental.

The new advance inverter functions will first have an impact upon the operation of the distribution system and the labor involved to learn and understand how the advance inverters will operate under normal and contingency conditions. Dakota Electric plans on using the information from the production meters to better understand how the DER generation interacts with the distribution system. The production meter will provide voltage and other power quality information and, if necessary, Dakota Electric will have the ability to install metering which will monitor VAR production from the DER generation. Dakota Electric could see this supporting future ancillary services or allowing the identification of advanced inverter settings which are impacting production through the use of the volt/watt functions or other advanced inverter functions.

8. 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).

The calculation of loss on a distribution system is not always straight forward. With thousands of meters on the Dakota Electric distribution system, it is presently impossible to read all the meters at the same time. With the implementation of the AGi project, Dakota Electric will be able to read all of the meters together and will then have an improved knowledge of the system losses over a given period of time.

Dakota Electric maintains records of the monthly energy purchases from Great River Energy, the monthly energy sales to the 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 Great River Energy. These energy loss values are then converted to a percentage of the total energy purchases from Great River Energy.

Table 2 is showing the monthly loss percentages for each month of 2018.

Table 2. 2018 Monthly Loss Percentage

2018 - Months	System Loss Percentage
January	-0.995%
February	-3.412%
March	7.210%
April	-3.572%
May	14.744%
June	6.045%
July	4.486%
August	0.220%
September	-9.511%
October	-2.954%
November	7.786%
December	7.631%
12-Month Average	**2.460%**

One can quickly notice that the calculated monthly percent losses varies greatly from month to month. The reason for this variability is due to timing of the readings of the respective meters at the substations and member service locations.

The energy delivered by Great River Energy is metered at each of Dakota Electric's distribution substations. All the Great River Energy substation meters are remotely read each month, at midnight on the last day of the month. With this process of reading the Great River Energy substation meters, the energy provided to Dakota Electric is recorded on a monthly basis, from the first day of each month to the last day of each month.

The energy which Dakota Electric provides to the member's, is metered at over 120,000 meters for each of the 108,000+ member's services. These meters are manually read each month, by meter readers which travel to each meter. The meter readings at each of the member's services are done throughout the month and thus do not correlate with the Great River Energy monthly substation readings.

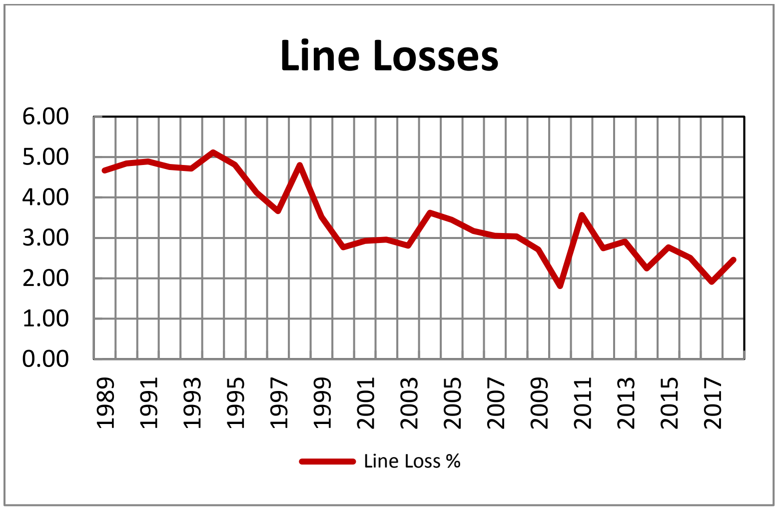
To better explain this process, about one-fourth of the Dakota Electric members meters are read each week, and thus some of the energy recorded for the present month was consumed in the prior month. For the services which are read during the first week of the month, three-fourths of the energy recorded on the meter was consumed in the last three weeks of the prior month.

One can see from the monthly percent losses that for months such as June, where the members actual monthly energy consumption is greater than the usage in the prior month, the calculated losses are greater than actual. This is due to the power purchases from Great River Energy being greater in June than May and the members meter reading reflecting only a portion of the increased June usage. The reverse is true in September, when the September Great River Energy purchases are less, but the members September meter readings include portions of the higher August usage.

The AGi project includes the installation of meters which are remotely read and will support obtaining nightly midnight readings each evening and provide 15-minute interval data for each of the meters. One of the benefits of the AGi project is to provide daily meter readings from all of the Dakota Electric meters. From this data, meter readings which are coincident with Great River Energy's monthly meter readings can be used for the purpose of calculating distribution losses. Once the AGi metering system is fully installed, and assuming few if any members choose to opt-out of the metering system, accurate monthly energy losses will be able to be calculated. If too many Dakota Electric members choose to opt-out of allowing the installation of an AGi meter, the benefits from coordinated meter reading values could be lost.

For accounting and analysis purposes, Dakota Electric uses the 12-month, 3-year and 5-year averages of the monthly distribution losses. Graph 4 shows the 12-month average losses for each of the last 10 years. The 12-month average losses can be affected by the meter reading alignment issues between Great River Energy and how Dakota Electric reads the meters, but the 12-month averages are less effected due to the similar seasonal issues seen each year at the end of the year.

Graph 4. Dakota Electric Historical Line Loss



As shown on Graph 4, the Dakota Electric distribution system losses over the past 30 years, have significantly improved. This was accomplished through various changes including; equipment efficiency improvements, including the purchasing of distribution transformers which have lower losses; 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.

9. 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 following table shows the coincident demand on the Dakota Electric distribution system at the time of peak system demand for Dakota Electric (1) and at the time of peak demand for Great River Energy (2). The peak demand (kW) at the time of Great River Energy'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 Great River Energy peak would be greater than the Dakota Electric system peak demand.

Because 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 3. Historical System Peak Demand

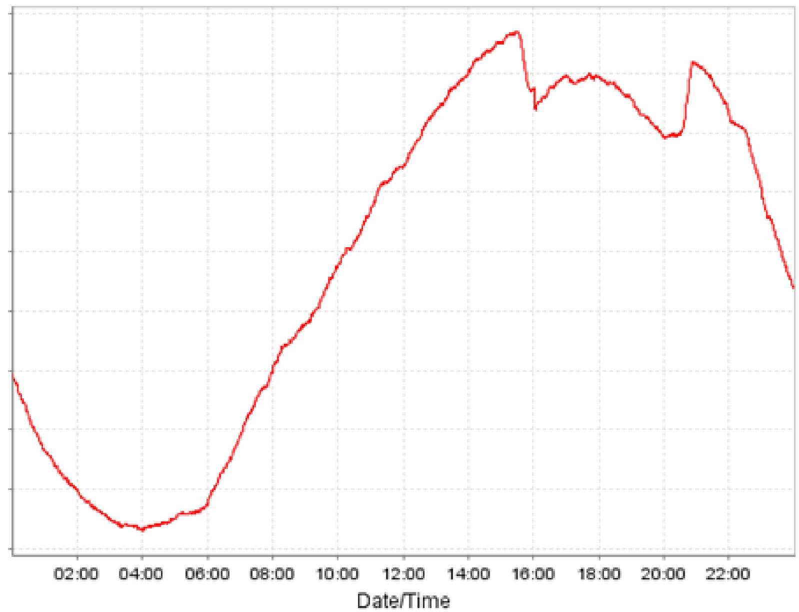
Year	(1) System Peak Demand (kW)	(2) Peak kW demand with Load Management Active
2012	498,320	416,863
2013	462,059	387,091
2014	420,679	361,159
2015	439,376	408,662
2016	451,613	379,487
2017	428,248	410,169
2018	445,681	412,520

(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 on a peak day. From Great River Energy's monthly billing summary reports.

(2) This is the peak hourly demand on the Dakota Electric system coincident with Great River Energy's peak demand. Dakota Electric has load control in operation during this period.

The following is a load shape for a typical summer peak day with load control.

Graph 5. Summer Peak Day with Load Management



10. System Data: Total Distribution Substation Capacity

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

The following table lists the total substation capacity for each of the past 10 years as of January 1st of that year.

Table 4. Historical Total Distribution Substation Capacity

Year	Total Distribution Substation Capacity (kVA)
2009	936,800
2010	974,100
2011	1,039,700
2012	1,064,700
2013	1,078,700
2014	1,084,300
2015	1,085,200
2016	1,110,200
2017	1,110,200
2018	1,135,200
2019	1,135,200

11. 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 kVA ratings for all the distribution transformers which provide electrical service to each of the members. The total kVA capacity is similar to the total substation capacity but the kVA capacity is less for the total distribution transformers due to the ability to load the distribution transformers to a higher level. The heavier a transformer is loaded, the shorter the life of the transformer. This is due to the heat created within the transformer from the electricity flowing through the unit. The hotter the transformer gets the more the insulating paper within the transformer is aged and the longevity of the transformer is reduced. Since the distribution transformers are physically small, the transformers can more easily dissipate the heat and withstand greater loading without failing. Distribution transformers also 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 must have spare capacity to allow neighboring substation's load to be switched over. As a result, substation transformers are not as heavily loaded as the smaller distribution transformers.

The data in the following table is from the GIS system. The data was compiled is for all the individual distribution transformer units. For some multi-phase installations, individual units are connected in a bank of transformers. For example, three single-phase transformers can be wired together to form a 3-phase bank. Dakota Electric periodically has saved information about installed distribution transformers and was able to provide three years of historical information regarding distribution transformers for this report. The data listed in the table below was not extracted at the same time each year but was saved at some point during the year listed.

Table 5. Total Distribution Transformer Capacity

Year	Number of Transformers	Total Transformer Rated kVA
2017	23,051	1,031,293
2018	23,271	1,055,552
2019	23,278	1,057,624

12. System Data: Total Overhead Distribution Miles

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

The total miles of 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. (Example: three-phase line includes four strung conductors. A three-phase line that extends for one mile has four miles of wire footage.) The amount of overhead line continues to decrease as urban areas expand and the existing wires are replaced by underground cables.

Table 6. Miles of Overhead Line

Year	Miles of Overhead Lines
2014	1,215
2015	1,205
2016	1,197
2017	1,195
2018	1,188

13. System Data: Total Underground Distribution Miles

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

Almost all new residential and commercial developments 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 7. Miles of Underground Cable

Year	Miles of Underground Cables
2014	2,819
2015	2,858
2016	2,898
2017	2,937
2018	2,961

14. System Data: Total Number of Distribution Customers

Section A.14. Total number of distribution customers.

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

Table 8. Total Number of Services

Year	Number of Member's (Services)
2014	104,066
2015	104,821
2016	105,867
2017	107,201
2018	108,274

15. 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 year 2018, the following are the costs incurred by Dakota Electric for the interconnection of DER generation. For 2018 and the years prior to the IDP order from the Commission, Dakota Electric has kept records of costs associated for DER generation integration support as a whole and has not accounted for these costs using the categories requested. Dakota Electric is working to modify their systems to allow the recording of costs by the categories requested. The following are the costs associated for DER generation integration support for 2018. The costs to make the necessary metering changes for the DER installation are not included in these costs. The metering costs have been accounted for within our general metering costs.

Table 9. Cost Incurred from Interconnection & Installation of DER Generation in 2018

Category	Expenses
Application Review	$57,437
Responding to Inquiries	
Make Ready	
Testing	

16. 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 calendar year 2018, the following are the charges invoiced to members for the interconnection and installation of DER generation.

Table 10. Total Charges to Members for DER Generation

Category	Invoiced $
Application Fees	$4,700
Metering	$0
Testing	$0
Make Ready	$0

17. System Data: DER Generation System Total Capacity Interconnected in 2018

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 the calendar year 2018, the following are the aggregate nameplate capacity of the different DER generation systems that completed interconnected to Dakota Electric's distribution system.

Table 11. Total Nameplate Capacity of DER Generation Interconnected in 2018

Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
2,406 kW	0	0	0	500 kW	0

18. System Data: Number of DER Generation Systems Interconnected in 2018

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 the calendar year 2018, the following are the total amount of the different DER generation systems that completed interconnected to Dakota Electric's distribution system.

Table 12. Number of DER Generation Systems Interconnected in 2018

Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
39	0	0	0	1	0

19. 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 following table reflects the number of DER generation systems interconnected to the distribution grid as of October 1, 2019 and the total nameplate capacity of those units.

Table 13. Total Number of DER Generation Systems Interconnected

	Solar	Solar/Storage	Storage	Wind	Gas Engine	CHP
Number of	216	0	0	12	127	0
Total Capacity kW	6,098	0	0	200.5	165,000 (1)	

Note (1) Engine Prime Rating

20. 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, 2019.

Table 14. Number of DER Generation Systems in Interconnection Queue

Solar	Solar/Storage	Storage	Wind	Gas Engine	Hydro	CHP
37	1	0	0	0	1	0

21. System Data: Total Electric Vehicles

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

Dakota Electric is not informed about all the electric vehicles (EVs) which are housed within the service territory. Dakota Electric does have special electric vehicle charging rates. In June of 2019, Dakota Electric filed with the Commission under Docket NO. E-111/M-12-874 the Annual EV Informational Letter. From this annual letter, as of May of 2019, members have enrolled 323 plug-in electrical vehicles on the Electric Vehicle charging rates.

22. 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. 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.

23. System Data: Battery Storage

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

At the time of this filing Dakota Electric is not aware of any battery storage units interconnected with the distribution system that operate in parallel. Dakota Electric has one application in process for a small energy storage system that is proposed for parallel operation with the distribution system. Dakota Electric is aware that there are many energy storage systems which are installed as UPS system, with no exporting capability, but the size or number of these systems is not known.

24. System Data: Energy Efficient Program

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

The Dakota Electric MWh savings from Energy Efficiency programs in 2018 were 26,284 MWh.

25. 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. Further in this report, in response to the Commission's Section A.31 question, Dakota Electric has provided detailed information about the amount of DER interconnected to Dakota Electric system by substation and feeder. Since within the IDP process DER is defined to include controllable loads, the information regarding the amount of connected controllable loads are listed in Section A.31.

The actual amount which would be realized when the control button is pushed is much different (lower) than the sum of the connected kW values. For each type of load there are different factors affecting the actual amount of load reduction realized when the control button is pushed.

<u>Air Conditioning</u>

Air conditioning (AC) will only provide load reduction during the hotter summer months. For any given day, the number of AC units which are turned on will vary. For residential AC, it normally takes one or two hot days before the members turn on their AC units. For a 90-degree day in May, most of the AC units are not operating. However, for a 90-degree day at the end of June, July or August, most of the AC units will be operating. Humidity and the length of hot days in a row will also affect the amount of AC run time. This is due to buildings heating up during the hot spell which leads to members turning down the temperature in their homes. Listed in Section A.31, Dakota Electric shows 50 MW of connected AC load. On a typical hot summer day, Dakota Electric would expect around 15-25 MW of actual load reduction from controlling AC units. For the future, the amount of demand reduction per AC unit is decreasing as older units are replaced with more efficient units.

Heat Pump

During the summer months (cooling periods) the heat pumps operate the same as an air conditioner. During the winter months (heating periods) the heat pumps operate just like during the cooling months, but their run time is affected by coldness of the ambient air. During the fall season there is little lag in the startup of the use of heat pumps as people do not wait to have several cold days before they start up their home heating system. The amount of connected kW for heat pump loads is around 10 MW. Dakota Electric would expect around 2-8 MW of demand reduction from controlling the heat pumps on a cold winter day.

Heat Devices

Heating devices could be in-floor heating, electric strip heaters or infrared heating. The use of these devices is variable as the heating device could be the main heat for a residence or supplementary heating for a room or garage. The amount of connected kW for heating devices is listed as 28.9 MW. The expected amount of load reduction is only around 5-10 MW due to the variable nature of how these devices are used.

Irrigation

Irrigation is primarily used for agriculture and most of the irrigation is configured to allow Dakota Electric to shed these loads during the peak load periods. As would be expected, irrigation usage is dependent upon the weather, so for some control periods there could be minimal load reduction from irrigation and other months there could be as much as 10-15 MWs of load reduction. Irrigation used for crops often is operated to distribute nutrients to the crops and may be operated even in naturally wet conditions.

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 are only heating the water during the night time (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 varies between 5-10 MW.

C&I Interruptible Genset

This category includes the member-owned generation systems where the entire building's electrical load is seamlessly transferred from the distribution system to the member's generation system. 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 around 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 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 rate 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 around 2-5 MW of actual load reduction is expected.

Table 15. Load Reduction Estimated by Program Type

Program	Number of Devices	MW Connected	MW Reduction Summer	MW Reduction Winter
Air Conditioning	51,162	150	15-25	N/A
Heat Pump	2,742	10	3-5	2-8
Heat Device	3,295	29	N/A	5-10
Irrigation	375	24	0-15	N/A
Miscellaneous	752	5	1	1
Water Heat	7,296	33	4-8	5-10
C&I Interruptible Generation	127	86	50-65	30-50
Curtailment	20	9	2-5	2-5
Totals	**65,769**	**346**	**65-124**	**45-84**

The load reduction numbers listed above are estimates. The actual amount of load reduction obtained during any control period is variable and is affected by many factors including; season, time of day, weather (both day of the control period and the weather on the days preceding the control period), and length of control period.

26. 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 Company may provide in the IDP any 2019 or earlier data in the following categories:

- *a) age-related replacements and asset renewal,*
- *b) system capacity expansion (capacity driven),*
- *c) system capacity expansion (reliability driven),*
- *d) projects to support new members (including metering, transformers and wires),*
- *e) system projects driven by governmental projects (road moves),*
- *f) grid modernization (advanced technologies)*

The following is a table showing Dakota Electric capital spending for construction over a 5-year period (2014-2018) using the alternative categories. The capital projects which are included in this table are all projects which occurred on the distribution system. None of the projects such as headquarters building, or internal software capital projects are included with these construction capital projects.

As discussed at the Commission hearings and within Dakota Electric's filed comments, Dakota Electric does not track construction projects using the categories requested. 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 modification to main lines are 200 and 300 series and substation work is the 700 series. Dakota Electric uses these classifications for budgeting and tracking the capital construction projects.

The following table is an <u>engineering estimate</u> of the breakdown between the categories using the actual total capital spending for each of the years.

Table 16. 2014 - 2018 Total Capital Spending

	2014	2015	2016	2017	2018
Age Related Replacement	$3,513	$2,814	$3,032	$3,506	$4,195
System Expansion (Due to Capacity)	$1,699	$2,457	$1,330	$2,247	$716
System Expansion (Due to Reliability)	$1,065	$1,488	$1,884	$1,449	$1,220
New Members	$2,652	$3,826	$3,429	$3,603	$3,006
System Project (Driven by Mandate)	$1,568	$1,956	$1,121	$1,924	$1,263
Grid Modernization (Advanced Technologies)	$465	$343	$973	$880	$361
Annual Total	**$10,962**	**$12,885**	**$11,769**	**$13,609**	**$10,762**

Note: All dollars are in Thousands

Table 16 has one number for 2018 that appears out of line versus historical levels in the system expansion (due to capacity) category. This value is much lower than the historical level. This was primarily due to reduced need to add additional substation capacity in 2018.

The allocation of the total capital dollars to the requested categories for each of the years is very difficult. 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 very subjective process. The following are some notes of how Dakota Electric decided to assign spending from the loan code categories into the why it was constructed 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. But for other activities, such as underground cable replacement or overhead line replacement, the selection of the category was less black and white. For example, Dakota Electric decides to replace an overhead line. The line is old and because of its age is weaker and considered a reliability risk. Due to the age and poor reliability, the line was replaced. Should this be placed into the Age-Related replacement category or the Reliability replacement category? For overhead lines, Dakota Electric has placed most of those costs into the age-related category, as these projects are primarily selected by age, to improve reliability.

For the underground cable replacements, the selection of these projects was by the number of failures (outages) which the cable experienced. The underground replacement projects are selected not by age but by the need to improve reliability. But since the underground cable replacement project does not increase system capacity, these projects were also included in the age replacement category. This made some sense as the underground cables replaced tended to be 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, have been added to the System Projects (Driven by Government) category as that appeared to be the best fit for those projects.

The costs shown in the table do not reflect the Contribution-In-Aid-of-Construction (CIAC) which was paid by the entity involved with requesting the project. Section A.27 provides the CIAC information by category and year.

27. 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 following is all the Contribution-In-Aid-of-Construction (CIAC) which Dakota Electric collected for each of the requested areas. Dakota Electric does not keep track of these contributions by area, feeder or substation.

Table 17. Contribution-In-Aid-of-Construction

	2014	**2015**	**2016**	**2017**	**2018**
Age Related Replacement	$171	$87	$150	$105	$0
System Expansion (Due to Capacity)	$85	$8	$1	$5	$0
System Expansion (Due to Reliability)	$0	$0	$0	$0	$0
New Members	$827	$1,650	$1,458	$1,344	$1,301
System Project (Driven by Mandate)	$183	$187	$246	$121	$890
Grid Modernization (Advanced Technologies)	$0	$0	$0	$0	$0
Annual Total	**$1,267**	**$1,931**	**$1,854**	**$1,575**	**$2,191**

Note: All dollars are in Thousands

28. 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.

The following are the forecasted 5-year construction capital spending for the categories listed above. As was discussed in Section A.26, the allocation of the forecasted capital spending in the following table, has been done using similar criteria.

Table 18. Five Year Forecast of Distribution System Spending

	2019	2020	2021	2022	2023
Age Related Replacement	$3,056	$2,997	$2,995	$2,979	$2,966
System Expansion (Due to Capacity)	$1,592	$3,194	$2,424	$2,289	$2,982
System Expansion (Due to Reliability)	$1,346	$1,357	$1,403	$1,395	$1,390
New Members	$4,356	$3,779	$3,973	$4,170	$4,468
System Project (Driven by Mandate)	$1,933	$1,837	$1,829	$1,819	$1,811
Grid Modernization (Advanced Technologies)	$1,342	$4,178	$3,471	$3,423	$221
Metering	$704	$9,901	$6,539	$1	$1
Other	$0	$0	$0	$0	$0
Annual Total	**$14,329**	**$27,242**	**$22,635**	**$16,076**	**$13,839**

Note: All dollars are in Thousands

Table 18 includes the AGi project budgeted capital spending. The cost of the AGi meters is included in the new Metering category and the cost for the load control receivers is included in the Grid Modernization category. The cost for meters for new consumers is also included in the new members category.

When looking at the above construction capital spending forecast, it is important to understand how Dakota Electric decides upon which projects are selected for construction and how that process works.

Dakota Electric completes a five-year capital construction forecast to help identify peaks and valleys in the future capital spending. Dakota Electric has a limited labor pool to accomplish projects and peaks in the capital spending would require increases in labor to accomplish, and inversely, valleys in capital spending would create an underutilized pool of labor. The 5-year capital construction budget forecast contains where those peak and valleys are identified and, if possible, potential projects are shifted to other years to help reduce the capital budget swings. Most individual projects are not identified beyond the next year.

The following types of projects may be forecasted out over future years. Except for the substation projects, the construction of these projects is not committed to until a few months before construction.

<u>Substation</u>

Substation projects are one of the few projects which must be planned for beyond the 1-year time frame. New substations require permitting and interconnection with transmission and typically have a lead time of 2-3 years from initiation 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 thus have the greatest impact upon the total budget. Forecasting substation projects to avoid multiple substation projects occurring on the same year, is important to the leveling of the annual budget and the impact upon the labor resources.

Reliability and Age-Related Replacement Projects

Capital dollars for reliability and age-related replacement projects are generally identified, but specific projects are not. For example, Dakota Electric has forecasted around $1.5 million dollars annually for the replacement of older failing underground cables. During the budget cycle for the upcoming year (September-November) the annual budget amount for underground cable replacement is adjusted. This category is affected annually by the number of other identified projects in the capital budgets, the expected amount of new services and government mandated projects. If there is a high number of these other types of projects identified, the labor is not available to address many reliability and age-related replacement projects. Conversely, if the failure rate of the existing fleet of underground cables is higher than typical, more dollars are budgeted for cable replacement. These concerns are taken into consideration when developing the budget for underground cable replacement in the next year.

Road Rebuild Project

The cities and counties provide a multi-year forecast of their road reconstruction projects, so this helps Dakota Electric estimate the overall budgetary impacts. The problem for Dakota Electric is, at this point in the process, the road reconstruction projects are only to the concept phase. The project has not gone through the public hearing stage and is not fully scoped and designed. Dakota Electric is only able to roughly estimate the impacts to the distribution system and the costs. The schedules provided by the cities and counties are also only estimates and many factors can cause the actual road reconstruction to be canceled, greatly modified or, as typically occurs, be delayed by one or more years.

Technology Projects

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

29. 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*

Within the capital spending for Dakota Electric there are hundreds of projects which range from very small projects, such as replacing a small transformer with a larger unit, to a million-dollar substation construction project. Dakota Electric has assumed that this question is not looking for have a list of every capital project from the small to the very large. Instead, to address the categorization and listing of planned distribution capital projects, Dakota Electric has used a threshold of $50,000 to define a project for inclusion in the listing. This appears to be a reasonable cutoff point to avoid listing a very large number of small projects and allowing the review to focus on the larger distribution system projects.

As discussed in other sections of this report, Dakota Electric does not generally commit to projects beyond a year, except for projects which have longer permitting or require equipment with longer lead times. Dakota Electric's planned projects include what has not yet been done in 2019 and what is proposed for 2020. Dakota Electric is including in this report the projects which are part of the 2019 budget, are being building in 2019 due to member needs, and are listed in the initial draft of the larger capital projects contained within the proposed 2020 capital construction budget. Within the 2019 project listing each project is noted by whether:

- the project was budgeted, planned and constructed
- the project was budgeted for but will not be constructed in 2019
- the project was not planned and budgeted but conditions occurred during 2019 to cause these projects to be designed and constructed.

Projects for connecting new, larger commercial services have not been included within this listing of capital projects as much of the cost for adding a new commercial service was for the transformer and other equipment required just to supply that individual member's electrical needs.

Appendix D – 2019 Capital Construction Projects > $50,000 has the list of construction projects for 2019.

Appendix E – Proposed Capital Construction Projects 2020 has the list of proposed construction projects for 2020. This list of projects is proposed and is preliminary and has not been approved by the Dakota Electric Board. The review and approval for the projects are scheduled for the November 2019 Board meeting.

30. Financial Data: Cost Benefit Analysis - Non-Traditional Distribution 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 the system peak demands and reduce the demand charges from the power supplier. The existing load management system has a limited capability to control types of loads in a targeted area. This ability of the existing load control system to trigger load control for a specific substation or groups of substations, while limited, has been used to reduce area peak demand when there have been substation failures. This capability has been used a handful of times over the past 30 years.

The new AGi load management system is designed to allow improved targeting of load control for a specific substation and possibly for individual feeders in the event of distribution system emergencies. With the new AGi's two-way communication and the ability to individually communicate with each of the load control receivers, the specificity of control will be available. With the existing load control system using a one-way pager signal, the ability to control specific load control receivers on a substation does not exist.

The use of member-owned generation to shed the members' load during peak periods has been used to defer distribution system construction. The cost-benefit analysis for the distributed generation program was based upon the power cost savings from the reduction in demand charges from Great River Energy. The C&I Interruptible – Rate 70 provides the member with a reduction in their rates in exchange for them to install a full capacity generator which is capable of providing all of their energy needs during control periods. Normally these control periods are during peak load periods, but they could be during distribution system emergencies. During emergencies, Dakota Electric has used these member-owned generation systems to reduce distribution peaks in specific areas to reduce the electrical demands.

The C&I Interruptible rate was advantageous for the member because the member would receive a rate reduction. This rate reduction, over a period of a few years, would pay for the generation installation and cover the cost of its operation. After the system was paid for the member would continue to see the rate reduction. The hope was to be able to use this rate incentive to target specific areas of the system to delay construction of substations and feeder capacity increases. Dakota Electric found that even with the rate incentive, it was very difficult to get specific commercial members to sign up for the program. Dakota Electric even formed a subsidy to construct, own and operate the generation for the business to eliminate all risk from the business. While having this subsidiary was helpful in convincing prospective members to commit to the program, it was still a hard sell to obtain enough load reduction in a specific area to delay distribution construction.

Only in one case, was Dakota Electric able to target a specific area and delay the construction of a substation for several years. There was a large commercial load, which was supplied by a very long, seven-mile feeder, the member was adding new load and was experiencing blinks and outages when storms would pass through the area. Dakota Electric was considering building a substation near this large commercial complex to supply the additional load and help improve the reliability. The capital cost of the substation would be over $2 million. Dakota Electric instead worked with this member to install a generation system to take their entire campus off the distribution system during peak times. Dakota Electric also installed a fast (sub-cycle) switched capacitor to help improve the power quality for the area. The generation capability was also used to isolate their load onto the local generation prior to storms coming through the area and help improve their reliability. Dakota Electric's subsidiary was able to construct, own and operate the generation and provide a rate reduction for the member. Because of this generation and the ability for Dakota Electric to have remote control to start and stop the generation when required, Dakota Electric was able to defer the construction of the substation until the member's load increased to a level that the construction of the substation was required. This deferred the construction of the substation for more than 10 years.

31. 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 A – DER Summary Report has the listing by substation and feeder for the existing DER deployment as of August 2019. The listing is by type and overall kW by feeder. Each feeder is totalized by substation and the list is totalized for the overall system. 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.

All of the Dakota Electric distribution system is considered one planning area and is maintained by a single service / work center located in Farmington, Minnesota.

32. 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 to be considered "high" DER penetration areas and does not have any areas forecasted to have high levels of DER penetration.

33. 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 any areas with extended abnormal voltage due to the operation of DER systems.

Dakota Electric does consider how it operates the load management system to avoid high voltages when it interrupts loads and well as avoiding low voltages when the load management system restores service to the interrupted loads. This operational constraint is both for the loads controlled by the load management receivers, such as water heaters and air conditioners, as well as the member-owned generation systems which isolate the member's load on the generation system and then separate from Dakota Electric during peak load periods. To accomplish this, the shedding and restoration of the controlled loads are staggered to reduce the impact on the local and overall system. Also, some of the larger loads are also ramped on and off the distribution system using an automated control system.

Since frequency is regulated by the eastern interconnection and is maintained at the ISO level, Dakota Electric does not have any areas with existing or forecasted abnormal frequency issues.

Section B. Preliminary Hosting Capacity Data

1. Feeder Load Levels

Section B.1. Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified).

Attached as *Appendix B – Substation and Feeder Minimum Loading Levels* is a spreadsheet showing annual minimum load (kW) levels and annual daytime (10am-4pm) minimum load levels for each of the Dakota Electric feeders for the 12 months between June 1st 2018 and May 31st 2019. Extracting daily (365) minimum values for each of the more than 165 feeders on the Dakota Electric system was not practical, as that would require a tremendous amount of labor and effort.

The base information was gathered by Dakota Electric's SCADA system from feeder and substation monitoring equipment. All of Dakota Electric's substations and feeders are monitored by the SCADA system. Data may not be available for short periods of time when either the entire SCADA system is taken out of service for database work and software maintenance or when the monitoring equipment within the substation is taken out of service for modifications or maintenance activities.

The demand (kW) values for each of the feeders are saved into a historical database by the SCADA system at a frequency of once every minute. The one-minute intervals are averaged over a 15-minute period as part of the process to extract the data from the historical database. The 15-minute periods allow for more efficient amount of data available for analysis and, more importantly, the 15-minute periods reduce the effect of minute to minute swings with the feeder loading.

The exported data from the SCADA historical database is the actual operational loading on each of the feeders. Thus, the values include times when:

- the feeder or portions of the feeder are out of power (storms, equipment failure, etc.),
- during switching events which transfer load to another feeder or add load from another feeder and,
- during periods of load control and other activities.

The historical data was extracted into a spreadsheet for each of the substations and then programmatically and manually cleansed to improve the usefulness of the minimum load data. It is important to understand that the loading on the feeders and substations are affected by many different factors. The following is an explanation of the different factors that affected the base data and how the data was cleansed.

Back-feeding Feeders

Since back feeding of the transmission system is one of the conditions which can affect the ability to interconnect and operate a DER, Dakota Electric has also included in the spreadsheet the minimum and maximum load levels for each of the substations. This additional information was provided as the overall substation minimum loading and is one of the key items to decide if transmission studies are required. It is important to note summing the non-coincident minimum or maximum values for each of the feeders on a substation is not the same as the coincident substation minimum values. The sum of the non-coincident feeder minimums does not equal the substation minimum as the feeders do not each reach their minimum values at the same time.

Distribution Switching

The distribution system configuration is in an ever-changing state. The configuration which is considered "Normal" is when all the switches and other distribution connections are in their normal state. In this normal state, the members' services are supplied by their normal feeder and substation. This normal state is what is modeled and studied during the annual and long-term planning processes and what is used for DER integration studies. The cleansed minimum feeder and substation load levels reported in this IDP, still reflect the transferring of some loads between feeders and substation due to distribution switching. Therefore, a minimum load level could be the result of an "Abnormal" condition when a portion of the feeder's normal load is being switched to another feeder for a period of time.

The distribution system is seldom operating in a "normal" configuration. It is common that at any point in time, one or more areas of the distribution system have distribution switching occurring where some of the electrical services are transferred (switched) to another feeder or substation. There are many reasons where a distribution operator will transfer a portion of a feeder or an entire feeder to another source. Some of these include;

Emergency Switching – Emergency switching is due to a failure of equipment. Equipment failures may occur due to storm damage, equipment malfunction, vehicles leaving the roads and damaging poles or other equipment, animals, etc. Emergency switching is unplanned but is typically for a short duration as the failed equipment is quickly repaired or replaced and the system is then switched back to normal.

During these events the feeder's load could be greatly reduced or, in the event of a total feeder or substation outage, the loading is reduced to zero. The problem in the extracted historical data is the SCADA system does not record a perfect zero number when a feeder or substation is out of power. The sensors are not perfectly accurate, and when the feeder is out of service the sensors report a small value. This is due to static electricity affecting the deenergized sensor leading to a small positive or negative value being recorded in the historical database. These very small values were programmable and manually removed from the historical data set to avoid them masking the minimum load value reported. Any time the feeder or substation load was below a small value, these outage events where eliminated from the data being reported as the feeder or substation minimum load.

As a result of this process, there are a few feeders which have a high penetration of DER integration and those feeders do go negative and back feed into the substation. The process to programmatically remove the near zero values from the minimum load also removed all negative values from the data set. The minimum load for these feeders is reported as “< 0”.

Maintenance Switching – Periodically pieces of equipment are required to be deenergized and taken out of service for maintenance and testing. Switching due to system maintenance is normally able to be planned for times when the overall impact to the distribution system is lower than some of the other drivers. Normally the maintenance activities are planned for lightly loaded periods, so a feeder or a portion of a feeder could be switched during a minimum loading time, and the feeder’s recorded minimum load value would be lower than its normal configuration. For the feeder where the load was switched onto, the feeder’s minimum load value recorded may have been greater than if recorded when the feeder was in its normal switched state.

Switching for Road Construction – Much of the distribution system is located along roads and the electrical cables, poles and wires are typically installed within the road right-of-way. The distribution facilities in the road right-of-way can be affected as the road is improved by the addition of traffic signals, addition of turn lanes, widening of the road to add lanes, etc. Many times, a section of a feeder (distribution line) needs to be deenergized and possibly moved or rebuilt to allow space for the road to expand. Road construction typically requires the distribution feeder to be switched to an abnormal configuration for weeks or months. The schedule for the road construction is driven by weather and most often occurs during the summer months and can be concurrent with peak system loading. When possible, Dakota Electric works with the road contractor to reduce the amount of time the feeder is out of service and, if possible, move the time frame of the outages to off peak months. Switching for road construction is one of the more disruptive activities for the distribution system.

Distribution System Construction – As parts of the distribution system need replacement or reconfiguration, other parts of that circuit may need to be deenergized or switched to another source to allow the construction to proceed. This is much like the switching in support of road construction, but in this case, Dakota Electric has more control of the project schedule. Dakota Electric will normally target this planned construction during period when the feeder is lightly loaded.

Load Control – Some of the substations and feeders have significant levels of demand-side management available. These feeders and substations are often at their minimum load levels during demand-side management control periods. Most of the feeders which have a high percentage of demand-side management will have the same or similar minimum load levels for the daytime minimum as the overall minimum reported load levels

Dakota Electric worked to provide the most useful minimum load data. As previously discussed, the minimum feeder load levels may include the feeder load level at times when some of the load was switched to another feeder. Dakota Electric does not keep records of when sections of a feeder are switched over to other feeders or substations. To keep this type of record would involve an enormous amount of work and there is no process or monitoring available to keep recording the amount of energy switched during the time period of abnormal state. It is important to understand that distribution switching occurs as a result of planned and emergency switching. Attempting to keep a detailed record of each and every incident of load transfer between feeders would be unreasonably time consuming and would negatively affect the restoration of service during storms and other unplanned outages.

Dakota Electric was able to eliminate the effect of most major feeder and substation outages in the final reported minimum feeder and substation loads. During the periodic substation maintenance, each of the feeders on the substation are manually switched to adjacent substations. During the steps of manual switching, the total substation load is gradually reduced and load on each of the feeders is gradually transferred to adjacent substations. These smaller than normal load levels during the transfer of the loads required significant manual cleansing of the data to individually eliminate these lower than normal feeder load levels.

Monitoring Sensors

Another type of data issue resulted from sensors on individual feeders failing or being taken out of service as part of maintenance for that device. During these incidences load data was not accurately recorded. While failures of equipment were very infrequent, it still required a significant amount of time to review each of the feeders to find and cleanse this inaccurate data. The cleansing was done through a combination of spreadsheet logic and manual cleansing of the data for each of the feeders and substations. The data cleansing process was very labor intensive. It required the effort of two people over a three-month period to complete the cleansing. The data reported was collected in June 2019 and covered the period of June 2018-May 2019.

For future IDP reports the significant manual labor effort required could be greatly reduced if, Dakota Electric was able to provide just the 31 substation minimum load levels, and not be required to provide the individual feeder minimum load levels. Dakota Electric has over 165 feeders which multiplies the labor required to review and cleansed the data. The benefit of knowing the feeder minimum load level information is not the same as knowing the substation minimum load levels. In fact, the sum of the non-coincident feeder minimum load levels does not equal the substation minimum load level. For Dakota Electric the substation minimum load levels will directly affect the ability to interconnect additional DER to the distribution system. The substation minimum load levels are directly related to the back feeding of the transmission system and the need to complete transmission level studies.

Section C. DER Scenario Analysis

1. DER Scenarios

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

Dakota Electric struggled with this request and how best to provide a response. Dakota Electric believes that the future adoption of DER in Minnesota and within the Dakota Electric service territory is unknown. The types of DER that are installed by the member's and the size of those systems continues to evolve. One possible response to this question was for Dakota Electric to estimate what is believed will be the adoption rates of the different types of DER, but based upon present knowledge, the estimate would be simply a guess. To compound matters, the possible configurations, types and sizes of DER are vast. Modeling the unknown penetration levels for each type and size would make a very dynamic and complex forecasting study.

Instead, Dakota Electric looked at this question and thought about the future. It is assumed the core of this question is looking to find how much DER can the distribution system support and at what penetration level would the distribution system start having problems. To reduce the complexity of the penetration study and desiring modeling results which could be useful for Dakota Electric in its future planning, Dakota Electric chose to only model solar DER. Of the different types of DER, solar appears to be the type of DER which is expected to be the dominant type for the near future. Dakota Electric considered modeling solar coupled with energy storage system or standalone energy storage systems as energy storage systems are expected to become a significant component of DER implementations. However, as energy storage systems are thought to help reduce the integration and operational issues and not negatively impact the operation of the distribution system, it was determined there was not a need to study energy storage as part of this initial study.

Demand Management was not included in the study because, Dakota Electric has already implemented a significant amount of Load Management or Demand-side Management. Because of this, there is a very low probability for Dakota Electric to have the ability to increase the penetration levels of demand management. Due to continuing improvement in home appliance efficiency, it is also believed the amount of demand management may actually decrease in the future. Thus, studying an increase in demand management did not appear reasonable.

Dakota Electric chose to study the existing distribution system with increasing levels of solar installations until the existing system was unable to support anymore installation without modifications. The desired outcome was to find out how much additional solar DER the existing distribution system can support, before problems emerge in the model.

The penetration modeling was in a two-prong approach; one approach assuming all the new solar additions were individual residential solar, sized at 10 kW. The concept was to add these small DER systems at residential services to the existing system base model until the model reached the point that problems were identified. The second approach was to take the existing system base model and add larger DER generation systems, much like the solar gardens, sized at 1,000 kW each. This approach would look at larger DER systems that are not sized to the load and identify at what level the existing system would start experiencing issues. Dakota Electric's desired outcome of the modeling approaches was to determine the general limit of penetration of solar DER generation and identify if there is a difference in penetration limitation between the solar DER generation sized to match the load and solar DER generation oversized for the load in the area.

Below in the DER Scenario Analysis section, is a description of the modeling and results along with discussion of including DER within the distribution planning process.

2. Methodologies to Create DER Scenarios

Section C.2. Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.

With Dakota Electric taking the approach of modeling how much DER generation can the distribution system integrate before there are distribution system issues, the need to match up the Great River Energy IRP forecast for DER adoption was unnecessary.

3. Processes and Tools for DER Adoption Scenarios

Section C.3. Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER adoption integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

The DER penetration modeling, which is documented in the "DER Scenario Analysis" section, found the integration of additional, sized-to-load DER generation does not appear to be an issue for the distribution system until the penetration levels reach the point where the energy is exported on to the transmission system. It is important to note that size-to-load is a capacity reference and not an energy one. A 10 kW solar system will meet the annual energy needs for a typical residential home. However, the 10 kW of peak generation is significantly larger than the peak demand of the residential load, which is 4-6 kW on average. Clustering of the 10 kW residential solar DER systems resulted in distribution system problems at a lower penetration level than if the solar DER systems were widely dispersed on the distribution circuits.

Similar to clustered 10 kW residential DER systems, the additional integration of 1,000 kW DER systems that are not sized to the load resulted in problems with the operation of the distribution system at a lower level of DER generation penetration. Most commonly, the problem that occurs with the levels of generation not matching the load is high voltage.

There is very little, if any, benefit from solar generation in reducing the need for distribution system equipment due to the DER generation output and load requirements not coinciding at the same daily time. The distribution system peak demand occurs between 6 – 7 p.m. daily while the output from the solar generation occurs between 12 – 2 p.m. More design and operational benefits would be possible depending upon if and how energy storage is combined with DER generation. Benefits of DER adoption or other non-wire solutions are addressed in more detail in Section E.

4. Impacts From FERC Order 841

Section C.4. Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM- 18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators).

It is unknown how the FERC Order 841 will impact the distribution system as the rules for how distribution interconnected energy storage systems can participate in the MISO market have not yet been defined. Dakota Electric expects vendors will want to utilize the distribution system for providing transmission services as the cost of physically interconnecting DER to the distribution system is significantly lower than interconnecting with the transmission system. The addition of energy storage systems interconnected to the distribution system for providing transmission services could have a dramatic effect on the distribution system itself.

The following are some of the potential, undetermined impacts from energy storage systems interconnecting with the distribution system and providing transmission services.

- Will FERC require regulation jurisdiction on a distribution system that is currently under state regulation, if a DER that is interconnected to the distribution system provides transmission services?
- How will the energy consumed by the distribution interconnected energy storage systems be sold to the energy storage system and how will the energy storage system be compensated for the energy generated? Will this be at retail, wholesale or some new rate?
- Energy storage systems which supply transmission services tend to be large DER systems, often several mega-watts in size. The interconnection of these large DER systems will consume the majority or all the existing hosting capacity available on a circuit and substation. Will residential and commercial customers who want to add DER be required to pay for system enhancements and possibly transmission studies, because all the hosting capacity is consumed by these large energy storage systems?

5. DER Scenario Analysis

Dakota Electric has considered incorporating DER into the distribution planning process, but given the penetration levels, Dakota Electric has not yet seen a need to incorporate DER generation into short term distribution planning. In looking at how DER generation could be incorporated into the distribution planning process two concerns arise:

- At what level does DER adoption cause technical issues with the distribution system affecting reliability, safety or power quality, and
- Can distribution planning rely on existing or forecasted DER owned and operated by other entities to delay or eliminate distribution projects?

Traditional long-range distribution planning involves identification of electrical problems relating to safety, power quality and reliability in a planning horizon of 20 – 40 years. Solutions to the identified electric problems are also evaluated on their merits relating to safety, power quality and reliability, along with concerns of project viability, public opinion and project costs. Incorporating DER adoption into distribution planning should not lower the expected level of safety, power quality and reliability of electricity to members of Dakota Electric. Possible benefits of DER adoption or other non-wire solutions are addressed in more detail in Section E.

Distribution planning revolves around capacity needs of the end-user. Capacity is a measurement that occurs instantaneously but in engineering models, is normally incorporated in 15-minute intervals. Dakota Electric routinely models the distribution system at the seasonal peaks to analyze for distribution system problems.

Dakota Electric looked at possible scenarios for the DER analysis. The possible variables including the adoption of energy efficiency, load management and member-owned renewable generation and storage systems were all considered. Each DER type can be used in different ways to lower capacity needs for specific periods of time. As seen in Table 19, the capabilities each DER type provides to the distribution system are shown along with the most common use case that provides financial benefit to the utility and/or consumer.

Table 19. Capabilities of DER Types

	Decreases Long Term Energy & Capacity Needs	Shifts Load Patterns	Contingency Uses	Best Cost-Benefit Use Case
Energy Efficiency	X			Lifetime cost savings in energy
Load Management		X	X	Minimizing of system peak
Renewable DER	Energy Only	X		Possible of avoidance of on-peak energy
Energy Storage		X	X	Minimizing of system peak

<u>Energy Efficiency</u>
Dakota Electric has a history of promoting energy efficiency to their membership and is categorizing this type of DER as mature. Dakota Electric expects members to continue to invest in more energy efficient appliances and machines. However, Dakota Electric does not expect member's energy efficiency investment to affect distribution planning as load growth is outpacing or at least matching the decrease in capacity needs from energy efficiency.

<u>Demand-side Management</u>
Dakota Electric currently has over 50,000 load control units installed at the members' homes and businesses. Dakota Electric started a demand-side load management program prior to 1990. Since that time, the demand-side management program has grown to include over 100 MW that can be controlled by Dakota Electric. This amounts to 20 - 25% of Dakota Electric's system peak demand which is available for control to reduce the capacity footprint. Dakota Electric considers demand-side load management as a mature technology in its service territory. Demand-side load management is a good tool to shift the load profile of specific loads, which can overall decrease the system capacity footprint for an area. Demand-side load management's shifting of load profile helps delay the need for additional capacity expansion of the distribution system. It is also important to note the load shifting is a short-term event,

normally lasting only 4 - 8 hours. Successful demand-side load management programs are designed to limit the impact on the participants of the program. Participants may choose to leave the program if the number and/or the duration of load control events increases where the impact to the participants becomes greater than the savings participants realize.

<u>Renewable DER Generation</u>

The adoption of member-owned DER generation systems is still a technology in its early stages in Dakota Electric's territory. While energy efficiency and load management DER technologies have a known predictable effect when used in load planning forecasts, DER generation systems are less predictable and less understood. Given the intermittent nature of the DER generation the distribution planner needs to develop assumptions about how the technology will react during peak capacity needs of the distribution system.

<u>Energy Storage</u>

Dakota Electric believes that energy storage systems have a bright future in helping provide safe, reliability electric energy for the members. As with renewable DER generation, energy storage systems are a new and developing technology. The use cases for energy storage are still being developed, however energy storage has the capability of providing firm energy to help reduce the capacity footprint requirements.

<u>Distribution System Model</u>

The overall goal of modeling the Dakota Electric system with increasing levels of DER integration was to identify at what points will the system require modifications to support integrating greater amounts of DER. It was also important to attempt to learn if there are any common failure points on the system. Choices had to be made on what type and sizes of DER would be studied when developing the model used to study the increasing levels of DER.

To identify what types of DER would be included, the following logic was used:

- Energy efficiency is to be considered static in the modeling. Energy efficiency is not considered to increase or will be expected to be offset by the growth in electrical demand.
- Demand-side load management is to be considered static in the modeling. Demand-side management participation is already at a very high level on Dakota Electric's system. It is unrealistic for additional penetration to occur.
- Growth of electric vehicles will only increase the amount of DER which is able to connect in the modeling. An increase in electric usage and demand level from the growth of electric vehicles should help support higher levels of DER integrations. As the modeling was to identify at what level of DER integration distribution system problems would occur, the additional energy usage and demand levels from electric vehicles may mask

potential problems if the electric vehicle adoption did not occur on specific circuits as expected.

The growth of electric vehicles will increase the capacity footprint of the distribution system which may require changes to the distribution infrastructure. Dakota Electric is planning on addressing the increased electrical demand from electric vehicles in the same manner as addressing increased electrical demands from new homes or businesses. There is not a need to model the adoption of electric vehicles in a low, medium and high scenario as this is currently performed in normal load forecasting studies.

As discussed, many of the various forms of DER are not expected to impact the Dakota Electric system at the present rate of adoption. Also, there are many different views of the future rate of adoption of DER. Instead, Dakota Electric has elected to study the impact of larger amounts of DER generation interconnected with the distribution system and attempt to identify the limitations for interconnecting DER with the Dakota Electric system. This is different than forecasting DER adoption rates using low, medium and high scenarios and then applying those forecasted levels to system models. Dakota Electric instead completed a set of DER Scenario Analysis looking at both residential sized DER generation and larger commercial sized DER generation integration. Instead of limiting the study to look at what amounts of DER generation integration are forecasted in the next five to ten years, Dakota Electric went beyond these forecasted levels and continued to increase the interconnected DER generation levels until issues within the model started to emerge.

For purposes of the DER Scenario Analysis, Dakota Electric used their 2018 summer peak model. From previous modeling experience it was known that DER integration issues are more prevalent at minimum load levels. At higher load levels the DER generation simply offsets the existing load. The actual minimum loads on the system occur during the night or early morning, but as the study was looking at solar DER penetration levels, estimated day time minimum load levels were used. Typically, minimum daytime load levels occur during the spring and fall for the Dakota Electric system. To model this, the loads in the 2018 summer peak model were reduced from the peak levels to 50%, so as to represent a typical, lightly loaded day that is representative of a day during the spring or fall months. Daytime minimum load on Dakota Electric’s distribution system during the summer, often will occur during periods when demand-side management is being utilized.

Due to the complexity of the study and the amount of time and effort required to model the many different scenarios on all 168 of the distribution circuits, Dakota Electric performed engineering analysis on a representative set of distribution circuits. The goal was to add solar generation to each of these representative circuits to determine at what level of renewable DER penetration do distribution issues start to become apparent. The analysis looked at various distribution circuits with the load profiles of urban residential, rural residential, urban commercial and suburban. Additional detail regarding each type of circuit classification is shown in Table 20.

Table 20. Circuit Load Profile

Load Profile Type	Description
Urban Residential	Single residential urban homes with some apartment complexes
Rural Residential	Single residential rural homes with a few agricultural services, irrigation services and small commercial services
Urban Commercial	Industrial and large commercial loads (manufacturing, hospitals, box stores and strip malls)
Suburban	Mixture of restaurants, hotels, small businesses, apartment complexes and some multiplex housing

Additional detailed information regarding the load levels of the circuits chosen to be analyzed are shown in Table 21.

Table 21. Circuit Loading

Circuit Name	Circuit Type	A Phase Peak Loading (kW)	B Phase Peak Loading (kW)	B Phase Peak Loading (kW)	Total Circuit Peak Loading (kW)	A Phase 50% Loading (kW)	B Phase 50% Loading (kW)	B Phase 50% Loading (kW)	Total Circuit 50% Loading (kW)
LCP17FB03	Urban Residential	837	947	874	**2,658**	420	475	439	**1,334**
LCP21FB06	Urban Residential	1,201	1,819	1,674	**4,694**	587	894	821	**2,302**
LCP20FB06	Urban Residential	947	622	801	**2,370**	461	303	389	**1,153**
LCP02FB01	Rural Residential	364	364	328	**1,056**	178	178	161	**517**
LCP04FB04	Rural Residential	655	655	510	**1,821**	323	324	251	**898**
LCP32FB01	Rural Residential	441	552	331	**1,324**	215	273	161	**649**
LCP10FB05	Urban Commercial	2,039	1,743	1,740	**5,521**	998	862	861	**2,721**
LCP13FB08	Urban Commercial	1,819	1,819	1,928	**5,566**	887	887	941	**2,715**
LCP31FB02	Urban Commercial	2,329	2,292	2,329	**6,950**	1,136	1,118	1,136	**3,390**
LCP09FB04	Suburban	1,419	1,382	1,673	**4,474**	692	675	818	**2,185**
LCP27FB02	Suburban	1,347	1,420	1,347	**4,114**	656	691	656	**2,003**
LCP14FB06	Suburban	1,056	1,165	1,020	**3,241**	514	568	496	**1,578**

The engineering analysis was performed using Milsoft Windmil® software. There were two separate analysis completed. One study applied 10 kW single-phase solar DER units across each of the circuits until distribution system problems appeared. The analysis also included examining the 10 kW solar systems added in different patterns; evenly disbursed on the circuit, located in concentrated areas and if the concentrated areas were located near and far from the substation. The analysis was then repeated on the same circuits, but this time applying larger 1 MW three-phase solar systems. For the 1 MW solar systems, the same patterns were studied for each of the circuits as was done for the 10 kW generation systems.

Assumptions made for the engineering analysis were:

- All circuits were assumed to be operating at 50% of their annual peak loading. This would be considered the typical daytime loading in spring and fall seasons.
- All substation voltages, the source for each of the circuits, were set at 122 volts.

- Line and substation regulators were turned off as they would not operate fast enough to prevent high voltage issues for variable generation sources.
- All renewable DER was assumed to be operating at 98% power factor, absorbing.

The engineering analysis did not look at flicker or voltage swings that would occur due to DER generation reaction to sudden changes, such as with cloud cover of solar DER generation. Nor did the analysis study cold-load pick up issues with the penetrations of inverter-based DER. These additional studies are very dependent upon the technology implemented, location and size of the DER integrated.

Table 22. Single-Phase 10 kW DER Systems Study Results

		Single-phase 10 kW DER Systems								
		Phase A			Phase B			Phase C		
Circuit Name	Circuit Type	Maximum Amount of DER (kW)	Number of 10 kW DER Systems	Limitation Reached During Modeling	Maximum Amount of DER (kW)	Number of 10 kW DER Systems	Limitation Reached During Modeling	Maximum Amount of DER (kW)	Number of 10 kW DER Systems	Limitation Reached During Modeling
LCP17FB03	Urban Residential	400	40	Reverse Power	480	48	Reverse Power	420	42	Reverse Power
LCP21FB06	Urban Residential	600	60	Reverse Power	600	60	High Voltage	800	80	High Voltage
LCP20FB06	Urban Residential	460	46	Reverse Power	300	30	Reverse Power	380	38	Reverse Power
LCP02FB01	Rural Residential	180	18	Reverse Power	180	18	Reverse Power	160	16	Reverse Power
LCP04FB04	Rural Residential	200	20	High Voltage	240	24	High Voltage	140	14	High Voltage
LCP32FB01	Rural Residential	220	22	Reverse Power	280	28	Reverse Power	160	16	Reverse Power
LCP10FB05	Urban Commercial	1,000	100	Reverse Power	1,000	100	Reverse Power	1,000	100	Reverse Power
LCP13FB08	Urban Commercial	1,000	100	Reverse Power	1,000	100	Reverse Power	1,000	100	Reverse Power
LCP31FB02	Urban Commercial	1,000	100	Reverse Power	1,000	100	Reverse Power	1,000	100	Reverse Power
LCP09FB04	Suburban	600	60	High Voltage	680	68	Reverse Power	820	82	Reverse Power
LCP27FB02	Suburban	660	66	Reverse Power	700	70	Reverse Power	660	66	Reverse Power
LCP14FB06	Suburban	520	52	Reverse Power	560	56	Reverse Power	500	50	Reverse Power

Table 22 and Table 23 show the capacity amounts of the different type of DER systems interconnected to the model circuits prior to a system limiting factor occur. Table 22 shows the capacity amount of single-phase, 10 kW DER systems scattered on a circuit by phase. Table 23 shows the amount of capacity of three-phase, 1 MW DER systems. As the engineering analysis occurred it became apparent there are two main limiting factors that occur as DER systems are added to Dakota Electric's distribution system. These limiting factors are reverse power flow from the distribution substation on to the transmission system and high voltage limits being reached.

Reverse power flow limitation is when the amount of DER added to a circuit exceed the loading on that circuit and, in many cases, the loading on the distribution substation. This can lead to reverse power flow onto the transmission. Guidance from MISO regarding reverse power flow from the distribution to the transmission is in development. Today, when this situation occurs, transmission system impact studies are required. The cost for completing a transmission study is quite expensive for a small 10 kW solar generation. Depending upon the size of the DER generation or future penetration levels of DER, the system impact studies may require the interconnection customer to pay for transmission upgrades.

High voltage limitation is when the amount of DER added results in the voltage on a portion of the circuit to exceed acceptable levels (126 volts). This limitation was found to occur when the DER systems were installed in a concentrated area on the same phase of a tap line. The greater the amount of DER generation coupled with the greater the distance from the substation where the DER was connected would increase the possibility of high voltage. DER generation that is integrated in a cluster, has a higher possibility of experiencing high voltages during operation.

It was noticed during modeling that the voltage regulation settings played an influential role with frequency of high voltage occurrence. Substation voltage regulation that was able to automatically adjust when the loading on the circuits increased or decreased as the result of changes in DER generation output, would help reduce the possibility of high voltage. Line drop compensation settings on the voltage regulation controls helped lower occurrences of high voltage limitations than with the voltage regulation modeled at a fixed voltage level. The aspect of substation regulation settings appropriately set to accommodate a higher level of DER will need coordination with inverter settings of DER systems on the circuit to effectively operate.

With the different types of DER being proposed for integration with the distribution system, some types will benefit from fixed voltage regulation. However, as these studies showed, other types may benefit from adaptive voltage regulation. Larger, energy storage or solar systems, which are connected to the distribution system within close proximity to the substation, may require the distribution voltage to be fixed to allow for their operation. The use of advanced inverter functions may require changes to accomplish the circuit voltage regulation. Dakota Electric will need to gain additional knowledge in these areas.

Adaptive voltage regulation using line drop compensation is used to help reduce system losses. The voltage on the circuit is raised during the daytime heavier loading times to reduce I^2R losses from the current running through the wires. The voltage is conversely reduced during the nighttime lighter loading times to reduce the no-load losses of the transformers. No-load losses of transformers are the majority of the distribution system electrical losses at night. Increased distribution system losses may be the tradeoff of utilizing fixed voltage levels for regulation to accommodate additional DER generation.

Table 23. Three-Phase 1 MW DER Systems Limitations

		Three-phase 1 MW DER Systems					
		Evenly Distributed			Located Bunched at End-of-Line		
Circuit Name	Circuit Type	Maximum Amount of DER (kW)	Number of 1 MW DER Systems	Limitation Reached During Modeling	Maximum Amount of DER (kW)	Number of 1 MW DER Systems	Limitation Reached During Modeling
LCP17FB03	Urban Residential	1,000	1	Reverse Power	1,000	1	High Votlage
LCP21FB06	Urban Residential	2,000	2	Reverse Power	1,000	1	High Votlage
LCP20FB06	Urban Residential	1,000	1	Reverse Power	1,000	1	High Votlage
LCP02FB01	Rural Residential	500	0	Reverse Power	240	0	High Votlage
LCP04FB04	Rural Residential	1,000	1	Reverse Power	500	0	High Votlage
LCP32FB01	Rural Residential	500	0	Reverse Power	300	0	High Votlage
LCP10FB05	Urban Commercial	3,000	3	Reverse Power	1,000	1	High Votlage
LCP13FB08	Urban Commercial	3,000	3	Reverse Power	1,000	1	High Votlage
LCP31FB02	Urban Commercial	3,000	3	Reverse Power	1,000	1	High Votlage
LCP09FB04	Suburban	2,000	2	Reverse Power	1,000	1	High Votlage
LCP27FB02	Suburban	2,000	2	Reverse Power	1,000	1	High Votlage
LCP14FB06	Suburban	1,000	1	Reverse Power	1,000	1	High Votlage

For the 1 MW sized DER generation, the location on the feeder was very important for the analysis. Since the 1 MW DER generation is not sized to the load, most of the generation is not offsetting load and as a result had a higher probability of causing high voltage. This was especially true the farther the point of interconnection was from the substation.

From the engineering modeling, Dakota Electric concluded that limiting factors *may* start to occur when the aggregated capacity amount of DER systems reaches 20% of the circuit's annual peak load. The engineering modeling also showed that limiting factors on circuits *may not* occur until the aggregated capacity amount of DER systems reached as high as 50% of the circuit's annual peak load. Key points to note for Dakota Electric from the engineering analysis are:

- Clustering of small DER systems can cause high voltage.

- Clustering of DER generation on one phase, can cause voltage and current imbalances on the distribution system, impacting system losses and voltage regulation
- The farther from the substation the DER is interconnected the greater chance of issues with the integration and operation of the DER generation.
- Less DER generation can be integrated on a circuit if the DER is not sized to the load.
- Larger DER systems can quickly take up the available capacity on a substation causing reverse power flow limitation to occur.
- Once reverse power flow into the transmission system is encountered, the ability to interconnect more DER on the distribution system is unknown and may be limited by transmission constraints.
- Concentrated amounts of DER generation may cause overloading of smaller distribution wires and cables; the standard size residential development underground cable is #2 AL which could be overloaded with 850 kW of aggregate DER.

6. DER Penetration Conclusions

The following are the conclusions of the DER penetration studies.

From the results of the study it appears as though the existing Dakota Electric system can accommodate the addition of large amounts of DER interconnected with the distribution system without significant distribution changes required. Dakota Electric presently has over 350 member-owned DER generators interconnected with the distribution system. Less than 200 of the member-owned DER generators are solar and wind systems with a combined rated capacity of 3.5 MW. The remaining DER systems are member-owned diesel generators which participate in the Dakota Electric C&I Interruptible rate and isolate the members' load with the generation during system peak period. These C&I Interruptible rate generators do not export to the distribution system and help reduce the system capacity footprint requirements. C&I Interruptible member-owned diesel generators are controllable by Dakota Electric and can be easily called into action by the Dakota Electric Control Center during times of need, including system emergencies.

These basic studies show that DER generation rated to around 20% of the daytime minimum load of each of the Dakota Electric circuits could be installed without significant distribution infrastructure changes. This would amount to around 100 MW of DER generation capacity. This assumes the DER is sized to the existing load at the point the DER is interconnected. It is possible that DER capacities up to the distribution system daytime minimum load levels could be achieved without significant distribution infrastructure changes, if the DER systems are sized to the existing loads and are also distributed across the distribution system. That could potentially amount to approximately 200 MW of integrated DER generation on the Dakota Electric system. Conversely, if the DER is not sized to the load or is concentrated in a few areas, there could be costly distribution infrastructure changes required at much lower levels of DER integration.

From a distribution capacity perspective, Dakota Electric has room to support the addition of more integrated DER generation without requiring costly distribution system modifications. This is true only if the DER generation is not clustered and the size of the DER generation is not greater than the local area load.

Section D. Long-Term Distribution System Modernization and Infrastructure Investment Plan

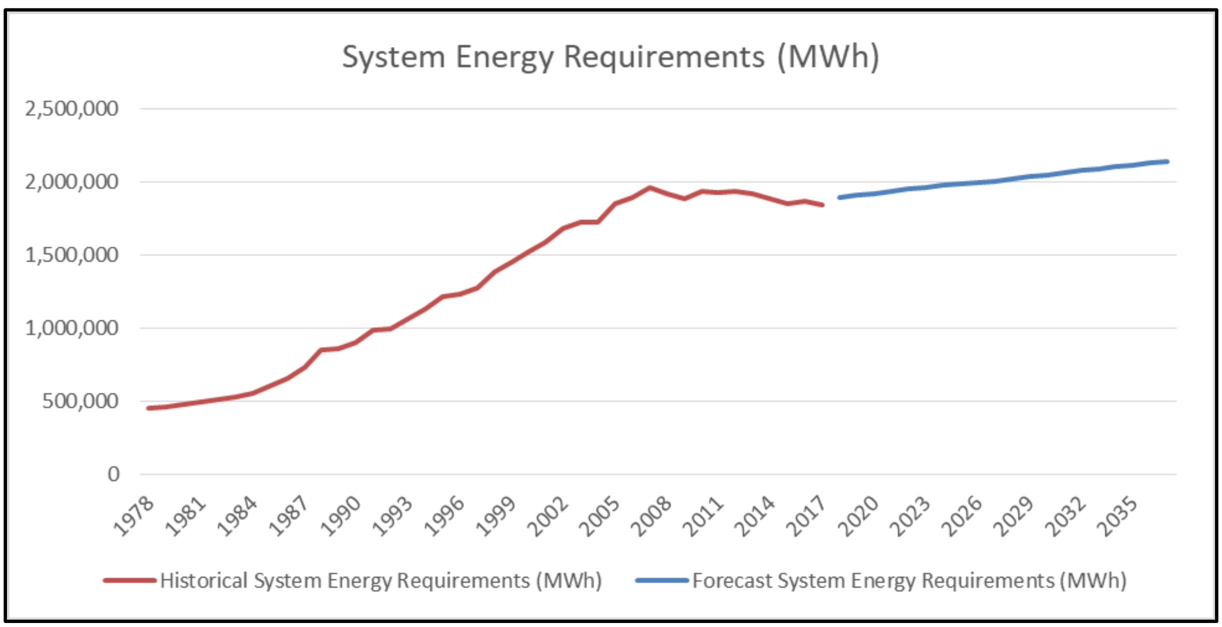
1. 5-Year Action Plan

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's Load Growth Forecast

Every two years, Great River Energy, along with all its member cooperatives develop a long-range load forecast (LRLF). This long-range load forecast is a collaborative effort. The last LRLF was completed in 2018 and forecasted the Dakota Electric loads by class for the next 20 years. Below is a graph showing the historical and forecasted system energy requirements for the Dakota Electric system.

Graph 6. System Energy Requirements

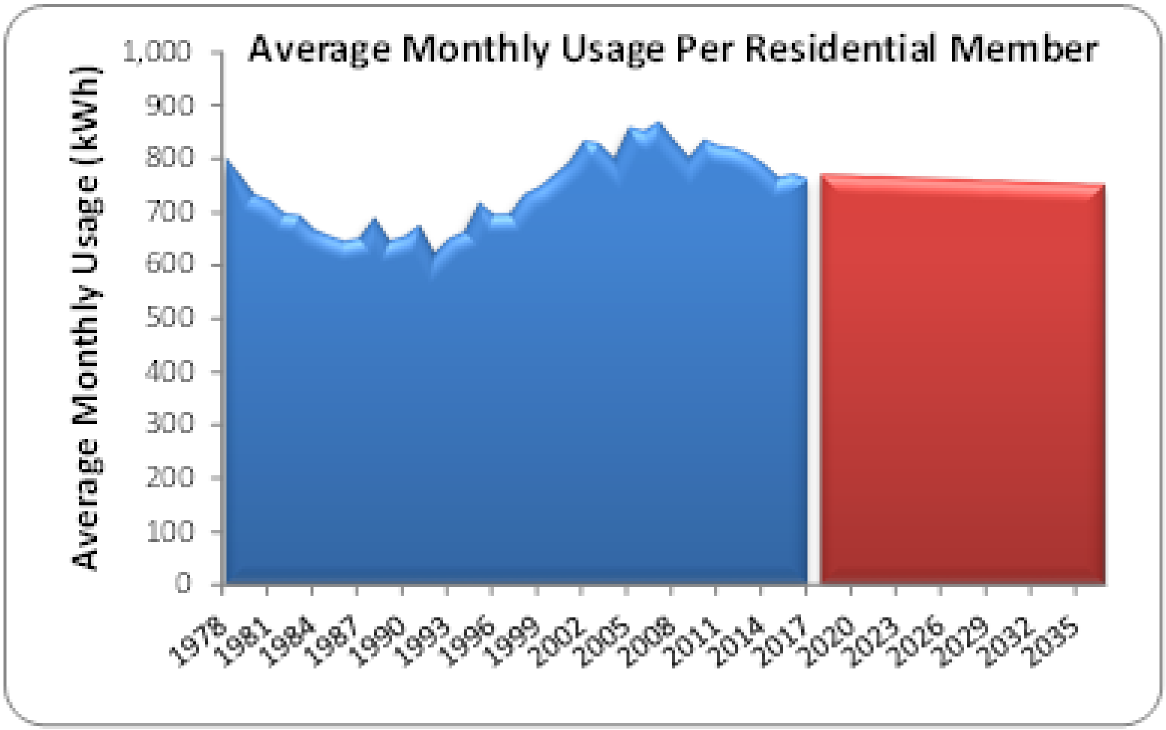


The forecasting of energy requirements for the Dakota Electric system was completed for each energy usage class. The classes include Residential, Seasonal, Irrigation, Small Commercial, Large Commercial, Lighting (public road right-of-way), Public Authorities, Own Use / System Losses.

The Residential class forecast was based upon residential energy usage forecasts and demographic household forecasts provided by the state of Minnesota Demographic Center and projections from Woods & Poole. In addition, periodic surveys of the Great River Energy residential members are conducted to better understand the types and number of existing appliances in residential homes. The appliance information then is used with the historical survey information to reflect trends in number and type of electrical appliances. From this information, and using weather adjusted historical energy usage data, a statistically adjusted end-use model is developed for the Dakota Electric Residential class.

In the 2018 load forecast, Residential class per service energy usage is forecasted to reduce from historical levels due to the continued conversion of appliances to more energy efficient units along with the conversion to LED lighting. The Residential class forecast assumed a small amount of member-owned residential solar installations and limited amount of new electric vehicle charging. The forecast assumed that overall energy consumption increases due to increased electric vehicle charging may offset the overall reduction in energy consumption due to member-owned solar installations. The forecast was designed to be an energy forecast; therefore, the demand implications of member-owned solar and electrical vehicle adoption were not directly addressed. Dakota Electric continues to look at the demand implications of electric vehicles. The greatest potential effect on the distribution system from the Residential class is the limited demand reduction from member-owned solar installations and the potential for increased system demand from electric vehicle charging over the evening peak.

Graph 7. Average Monthly Usage Per Residential Member



The Small and Large Commercial forecasts were based upon historical trends and information gathered through discussions with commercial accounts. As with the Residential class, appliance efficiency and LED lighting are expected to reduce the overall energy usage for the Small and Large Commercial services. For these services, additional energy reduction from the reduction in cooling requirements due to less heat generated by the new LED lighting systems is expected.

The remaining usage classes represent small percentages of the overall Dakota Electric electrical usage and thus do not greatly affect the overall energy requirements for Dakota Electric. A couple of significant changes in the forecasted energy requirements for the smaller energy use classes, included the forecasted reduction in energy usage by the Lighting class due to the expected shift to LED roadway lighting. Energy usage for this class is expected to be cut in half over historical levels in the next few years.

Overall, the forecasted average usage per residential service is generally expected to be lower in the future. Any growth in energy requirements for Dakota Electric, is expected to be driven by the addition of new residential and commercial services.

Five-Year Action Plan

One of the newer terms which is being used to describe the future energy grid is Transactive Energy. Transactive Energy is the broad term used to describe the use of market-based transactive exchanges between energy producers and energy consumers.

From the 2019 IEEE PES Transactive Energy System Conference (TESC) website:

> *Transactive Energy refers to the economic and control techniques used to manage the flow or exchange of energy within an existing electric power system in regards to economic and market-based standard values of energy.*
>
> *It is a concept that is used in an effort to improve the efficiency and reliability of the power system, pointing towards a more intelligent and interactive future for the energy industry.*
>
> *Transactive energy promotes a network environment for distributed energy nodes as opposed to the traditional hierarchical grid structure. The network structure allows for communication such that all levels of energy generation and consumption are able to directly interact with one another.*

Dakota Electric believes that the members do not want to be spending time making hourly or even daily decisions about sourcing their energy. Instead, Dakota Electric believes the members want the ability to make periodic choices between options for sourcing and utilizing the energy they consume. Dakota Electric's experience with load management options for the members has shown the Cooperative that given the right combination of economic incentives, ease of implementation and limited impact upon their lifestyle, many of the members will embrace those load management options.

As a concept, Transactive Energy appears to be a very flexible and enabling concept. In actual practice, to achieve a fully transactive energy exchange state, significant changes to the electrical grid, large investments in secure communication infrastructure, development of new economic constructs, and significant replacement of consumer's appliances with interactive units will need to occur. Dakota Electric is working towards a more interactive distribution system and one that provides the members with more granular information regarding the energy being consumed. The future interactive distribution system will also include more information for the members about how members are generating energy, if the member has installed renewable energy resources. This information will be available not only for Dakota Electric to use to improve the efficiency of the distribution system, but most importantly for the members to better understand how they use energy.

To accomplish this, Dakota Electric's Five-Year Action Plan for enhancing the distribution grid is focused on the completion of the AGi project. The AGi project includes:

- The installation of a meshed Radio Frequency (RF) communication network.
- Replacing of all of the existing metering with digital two-way communicating meters, typically referred to as AMI (Advanced Metering Infrastructure).
- The addition of a Meter Data Management System (MDMS) which will store the vast amount of metering data, including alarms and events from the edge devices.
- The replacement of all of the existing 50,000+ load management receivers which are mounted on the side of the member's homes and business.

The AGi project is the single largest project that Dakota Electric has ever undertaken and is requiring the focus of the entire cooperative over the next few years to successfully implement. Dakota Electric is trying to control any additional labor required to support other non-required projects and initiatives which are not in support of the AGi project. This is required to help ensure the successful implementation and expected benefits of the AGi project.

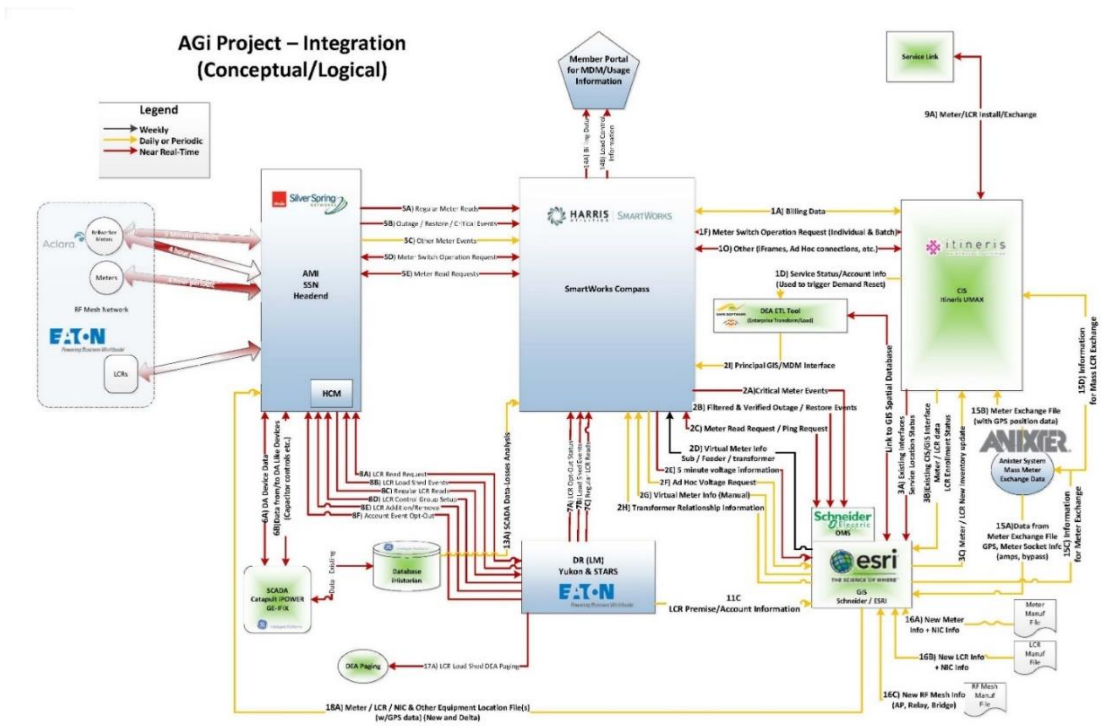
<u>AGi Project Implementation Plan</u>

Dakota Electric performed a very extensive review of how other utilities have implemented similar systems. In addition to internet and over the phone research, Dakota Electric visited nine utilities across the county whom had implemented the advanced metering system. From these visits Dakota Electric was surprised to learn that many of the benefits from the AMI/MDM systems were not yet being received. Much of this was due to limited integration between the new systems and the utilities' existing systems. For most utilities, the integration had not yet been completed even several years after the meters were exchanged in the field.

Dakota Electric learned that the effort to complete the system integrations required between the new computer software systems and the utilities' existing software systems was significant. For many of the utilities, the necessary integration had either not yet been fully completed or some integration had not been started. The limited or lack of integration appeared to be partially due to the large effort required to coordinate the installation of the meters and the RF communication network across the utilities' service territory and partially due to the focus of the utilities' project on getting the meters and AMI system quickly installed. Only after the meters were installed, the utilities turned to integration of the AMI/MDM system with the rest of the utilities' existing internal systems.

Dakota Electric is trying a different approach to the implementation of the AGi project. Since the Dakota Electric's AGi project includes the installation and integration of three major systems, all supplied by three different companies; AMI (ITRON), MDM (Harris) and Demand Response (Yukon - Load Management); the integration requirements are even greater than is typical for the installation of just an AMI system. For the AGi project, the first phase of the project is to set up all the new and existing systems in a test environment and to complete testing of the integrations between the systems. This testing is performed prior to installing meters and load control receivers in the field. As 80% of the capital dollars for the AGi project are to purchase and install the edge devices, meters and load control receivers, the project schedule milestone of attaining the functionality working first should provide the expected benefits earlier in the project. The traditional project schedule of implementing the AMI system, installing the meters and then working on the integration could work provided there was enough internal labor to support all of the design, programming and testing required. For Dakota Electric, along with most utilities, the internal labor is from a very small pool of existing employees who already have other job responsibilities. The integration test approach first is Dakota Electric's hope for a smooth deployment of the entire AGi project.

Figure 3. Integration Chart for the Dakota Electric AGi Project



2. AGi: Overview of Investment Plan

Section D.1.i. Overview of investment plan: scope, timing, and cost recovery mechanism.

Dakota Electric has filed with the Commission the project costs for the AGi project under Commission Docket E111/M-17-821. Dakota Electric has also received approval to utilize a tracking system to recover the additional costs of the AGi project as the costs are incurred during the implementation of the project.

The project is broken up in to three phases and one continuing phase.

CAT - Conformance Acceptance Testing. This phase is the implementation of the TEST software environments, including the integration between the new and existing utility systems. A physical testing area is located at Dakota Electric which includes the installation of approximately 25 meters and load control receivers and a TEST RF mesh network to support communication between the testing area and the AMI software headend.

SAT - Site Acceptance Testing. This phase includes the replacement of 5,000 meters on existing members' homes and businesses and the replacement of a few hundred existing load control receivers. SAT also includes the installation of the initial section of RF mesh communication and the installation and integration of the PRODUCTION software environment.

PAT – Performance Acceptance Testing. This phase is the replacement of all the meters on the Dakota Electric system and many of the load control receivers. Once the SAT phase of the project has been complete, most of the functionality will have been tested and in operation. The remaining testing revolves around the overall performance of the RF mesh system with 150,000+ edge devices (meters and load control receivers). There are specific contractual requirements the vendors must meet at the end of the PAT phase of the project.

The AGi project was scheduled to begin in September 2018 and continue until 2023.

2018 September - 2019 October – CAT phase of the project. Establish TEST environments; installation of the Testing Area with meters and other edge devices; integration between the different software systems and testing of the functionality of the integrated system.

2019 September – 2020 May – SAT phase of the project. Establish the PRODUCTION software environment and integration between the systems; installation of 5,000 meters and a few hundred load control devices. Continue testing of functionality including delivery of functionality not completed within CAT phase. The SAT phase also includes the installation of the initial portion of the RF mesh network.

A key milestone at the end of the SAT phase of the project is the delivery of the promised functionality for the system. Dakota Electric has the right to not go forward with the PAT phase of the project until the promised functionality is available. Dakota Electric does not plan on moving into the PAT phase until the required functionality of the system is available.

2020 Summer – 2021 – PAT phase of the project. Installation of the rest of the RF mesh communication network; the replacement of the remaining 115,000 plus meters; the identified and replacement of the oldest load control receivers and known receivers that are failing to control loads.

2021-2023 – Continuing phase of the project. This involves the continuing replacement of the remaining load control receivers and other complicated meter exchanges. The first priority of this phase is to receive the benefits of an advance grid infrastructure installation. The second priority is to use the meter data to identify and replace the load control receivers which are failing to control the loads. The third priority is replacement all remaining load control receivers.

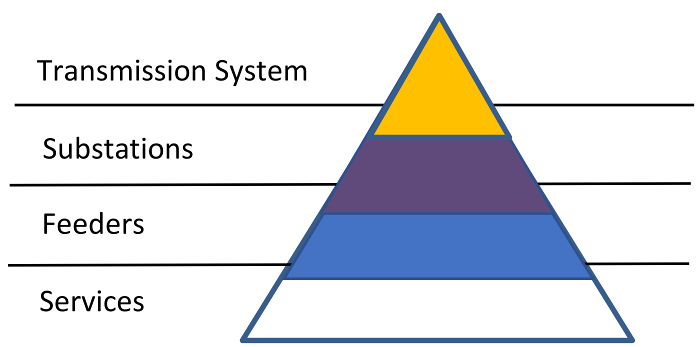
3. AGi: Grid Architecture

Section D.1.ii. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.

The AGi project is Dakota Electric's focus to modernize the utility's grid. Dakota Electric has, at all of the substations, already replaced feeder relays with digital relays and installed SCADA monitoring and control systems. Dakota Electric believes that this effort will provide a foundation for the future of the distribution system.

Dakota Electric believes that implementing AGi technology is an essential building block and platform for deploying other advanced grid systems and services in the future. The implementation of AGi is a foundation for the future and continues improving visibility of the grid.

Figure 4. Electrical Visibility Triangle



Using the visibility triangle shown in Figure 4, one can see the development of visibility for the different parts of the electrical system. In the 1980s, utilities started at the triangle top by obtaining visibility of the transmission systems and transmission substations. During the 1990s and 2000s, utilities completed the installation of SCADA to achieve visibility at the distribution substation level. The next step in the evolution is to increase visibility of the feeders and at individual services. In addition to providing key operating information to the utility, the increasing level of visibility will enable the members to have knowledge and understanding of their energy usage.

Dakota Electric believes that it must begin preparing for a future state that integrates many technologies not present today but will require advanced capabilities for monitoring, communication and control. The system-wide communication network provided by the installation of the AGi system will support future operational monitoring. This monitoring will be required to support the operation of the system with the installation of renewables, such as solar. Together these advanced grid systems will provide options for Dakota Electric to increase service levels and meet the future expectations of the members. The AGi technology will also provide the foundation and flexibility for Dakota Electric to respond to emerging issues as they arise.

Dakota Electric's mandate to provide electrical service to the service territory drives the need to plan for the expected worst-case conditions. The members look to Dakota Electric to provide safe, reliable and economical electrical energy for their homes and businesses. Failure to provide safe and reliable electrical service would negatively affect the members lives and their businesses. Thus, planning for the future electrical needs of the members and developing the electrical distribution system to meet those needs is a core function of Dakota Electric.

4. AGi: Alternative Analysis of Investment Proposal

Section D.1.iii. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.

To put the AGi decision in perspective, it was important to consider what happens if Dakota Electric did nothing regarding implementing AGi technologies. A decision to do nothing did not mean that nothing happens. Doing nothing meant accepting the status quo which, in and of itself, is a decision. It is equally important to understand that the decision to do nothing carried significant risk and cost.

The overall costs of continuing with the status quo versus the cost to implement AGi technology were very similar. The additional services supported by the Advanced Grid Infrastructure and the operational flexibility available with the AGi systems were the deciding factors between the two decisions. The deciding fact to install new technology instead of continuing to spend dollars installing old technology was due to the inability to obtain the additional services and operational flexibility benefits the new technology had to offer. For a complete analysis of the economics behind the AGi decision, please reference the Minnesota Public Utilities Commission Docket No. E-111/M-17-821.

5. AGi: System Interoperability and Communication Strategy

Section D.1.iv. System interoperability and communications strategy.

System interoperability is a very broad and deep topic. Dakota Electric first evaluates which systems need to be interconnected so the systems can interoperate. Much of the effort to identify and refine what interoperability and communication is required to support transactional energy is still in its early stages. Once the interoperability requirements are defined then modifications to Dakota Electric existing systems to support these requirements can be initiated. Dakota Electric's AGi project is designed to be flexible and it is hoped that the foundation created by the AGi project will be able to support new communication requirements.

Dakota Electric has a long history of working towards interoperability with the members' distributed energy systems, including both generation and demand management systems. Creating near real-time data exchanges takes a considerable amount of work and incorporates many systems that require granular data. This supporting data must be kept accurate (verified and evaluated) for the systems to operate reliably. The gathering, storing and maintenance of data is itself a significant task. Dakota Electric has been working on developing systems which will become the hub for data therefore making the use of this data convenient and accessible for the employees and systems which will share in the usage of the information.

The first major integration and interoperability of internal data systems at Dakota Electric was completed and put in use in the 1990's with the installation of the SCADA system and the remote control/monitoring of the substations and member-owned generation. The load management system was installed alongside and integrated with the SCADA system. The load management system included the installation of thousands of load control devices and a centralized load control master station.

The interoperability and installation of data management platforms continued in 2009 with the installation of the GIS and work management systems. The GIS system installed in 2009 was not the first GIS system at Dakota Electric. This GIS system version was the first fully integrated GIS system with an asset management component, operational management system (OMS) and close integration with the work management and accounting systems. This created a data hub which supports near-real time network connectivity model and graphical representation of the electrical distribution system data. The OMS was installed as part of the GIS system and allows efficient management of the electrical distribution system topology and restoration of outages. The GIS project also created a construction management system (work management) where all parties involved with the design, approval, procurement and construction of a project used the same set of systems with access to the same data.

The AGi project is designed to continue that integration philosophy. With the implementation of the meter data management system, Dakota Electric will continue the integration of many of the other islands of data. Systems, such as the SCADA and load management systems, will be able to report data and retrieve data from the MDMS.

The AGi platform is one large step towards the creation of an accessible grid that will support new products, new services and will help provide opportunities for integration of distributed technologies.

The future is unclear what next interoperability steps will be required once the AGi project has been completed. It is unknown what the interoperability requirements will be to support transactive energy. Dakota Electric is working to position our distribution system to be agile for incorporation of future interoperability options.

6. AGi: Cost and Plans Associated with Obtaining System Data

Section D.1.v. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.)

As a direct result from the implementation of the AGi project, Dakota Electric will be able to gather interval data from services which have installed DER (generation and load management) and electric vehicles. The 15-minute interval data will be gathered by the AGi meters and stored within the MDMS for analysis. The availability of production data from the DER production meters is important for understanding the actual operation of the DER generation systems. Aggregated data for the different types of installations can then be used to better understand and plan for DER adoption.

7. AGi: Interplay of Investments with Other Utility Programs

Section D.1.vi. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)

Dakota Electric is committed to supporting continued efficiency improvements with both the members' facilities and with the Dakota Electric system. There is nothing in the future plans that are expected for Dakota Electric to change that focus.

Dakota Electric strongly believes that the value of the existing load management programs to the members are significant. As part of the AGi project, Dakota Electric plans on continuing to improve and expand the load management programs.

The investment in the AGi project is designed to help the engineers to more efficiently plan and design the distribution grid. The data provided by the AGi end point devices, such as meters, will help optimize the utilization of the distribution grid assets and support the addition of DER.

8. AGi: Customer Anticipated Benefit and Cost

Section D.1.vii. Customer anticipated benefit and cost.

The AGi project is expected to slightly increase the cost to the members over the next few years. As the AGi system becomes fully functional, the AGi system is expected to moderate future increases in costs of delivering electrical services to the members and provide increased options for the members. The AGi project is replacing old equipment with new, utilizing new technology to allow Dakota Electric to serve our members even better.

The AGi project is expected to enable greater member engagement by providing more information to the member on how the they use energy. The AGi project will empower the members to help them identify energy saving opportunities and provide information to help the member utilize other rate options.

9. AGi: Customer Data and Grid Data Management

Section D.1.viii. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties).

The AGi project includes a member portal where the member may view and utilize the information about their energy usage. The member energy use is considered private and Dakota Electric will not disclose this information to third parties without the members' permission. The member portal will support members being able to download the information and allow the member to share information about their usage with third parties, if they wish.

Dakota Electric will internally use the members usage to ensure the electrical system has enough capacity to supply the electrical needs of the member and to monitor the quality of the power delivered to the members' service. Dakota Electric will also use data that is aggregated with many other services for distribution planning, reporting and usage data analysis. This aggregated usage data may be shared with other entities for business reasons, such as Great River Energy and the Minnesota Public Utilities Commission.

10. Plans to Manage Rate or Bill Impacts

Section D.1.ix. Plans to manage rate or bill impacts, if any.

Dakota Electric is a not-for-profit utility, consequently any costs which are incurred by Dakota Electric are paid for by the members. Dakota Electric will continue to work on controlling and identifying ways to reduce costs throughout the organization. Dakota Electric will continue to provide ways for the members to reduce their bills through energy efficiency and load management options. The implementation of the AGi project will only enhance the ability of the members to make informed choices by providing members with more information on their energy use.

11. AGi: Impacts to Net Present Value of System Costs

Section D.1.x. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt).

The AGi project is expected to help mitigate future costs for Dakota Electric. The lifetime costs of the AGi project are expected to be offset by the benefits received. Even if the AGi project was not initiated, Dakota Electric was expecting to spend similar dollars implementing and maintaining old technology. The old technology does not provide the functionality that the AGi project will provide and the old technology could not be leveraged to lower costs for Dakota Electric's membership. For a complete analysis of the economics behind the AGi decision, please reference the Minnesota Public Utilities Commission Docket No. E-111/M-17-821.

12. AGi: Cost-Benefit Analysis

Section D.1.xi. For each grid modernization project in its 5-year Action Plan, Dakota Electric should provide a cost-benefit analysis.

Dakota Electric provided an extensive cost-benefit analysis of the AGi project as part of its filing for rate recovery approval. For a complete analysis of the economics behind the AGi decision, please reference the Minnesota Public Utilities Commission Docket No. E-111/M-17-821.

At this time, Dakota Electric has no other grid modernization projects planned.

13. Status of Existing Pilots or New Opportunities for Grid Modernization

Section D.1.xii. Status of any existing pilots or potential for new opportunities for grid modernization pilots.

Dakota Electric is focused on completing the AGi project and is in the middle of the pilot (SAT) phase of the project. No other grid modernization projects are planned. The AGi project is "all hands-on deck project" and is consuming all existing labor resources.

Section E. Non-Wires (Non-Traditional) Alternatives Analysis

1. 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's has several projects expected to be constructed over the next 5 years which approach or exceed two million dollars. The following is a brief summary of each of those projects, followed by a more detailed analysis for each of the projects listed.

1) The Advanced Grid Infrastructure (AGi) project is the single largest project ever untaken by Dakota Electric. This project has been presented to the Commission (Docket No. E111/M-17-821) and has received approval for rate recovery by the Commission. The AGi project includes; the installation of a meshed RF communication network; the replacing of all of the existing metering with digital two-way communicating meters, typically referred to as AMI (Advanced Metering Infrastructure); the addition of a Meter Data Management System (MDMS) which will store the vast amount of metering data, including alarms and events from the edge devices; the replacement of all of the existing 50,000 plus, load management receivers which are mounted on the side of the members' homes and businesses.

   The AGi project started in 2018 with completion of the metering portion of the project expected by the end of 2021 and the load management portion of the project completed by the end of 2023.

2) The second project is the conversion and rebuilding of the existing Yankee Doodle Substation from 69kV to 115kV. This project was in planning and permitting for several years and construction was started in the fall of 2019, with completion expected in spring of 2020. The project is in support of Great River Energy's transmission needs to move load from the aging 69kV system to the 115kV transmission system. The Yankee Doodle substation estimated cost for Dakota Electric is below $2 million dollars, but if one includes Great River Energy's transmission construction costs the total dollars spent will exceed $2 million dollars.

3) The third project included for discussion involves the addition of capacity to the existing Dodd Park Substation. The addition of capacity is planned to be done through the addition of a second substation transformer and switchgear within the existing substation fenced in area. The Dodd Park substation is located in Lakeville Minnesota and new residential developments are being constructed in the area serviced by the Dodd Park Substation. Additional feeders and substation capacity are required to move the energy from the existing transmission system to the new residential and commercial loads. There is no firm date for this construction, but it is expected to be required in the next couple of years, depending upon the pace of new home construction.

4) The fourth project selected for this IDP report is the siting and construction of a new substation near Elko-New Market, Minnesota. The Dakota Electric service territory around Elko-New Market is currently supplied by a substation which is several miles north. The existing substation and the feeders connecting the Elko-New Market service area to the substation have a limited amount of available spare capacity. The contingency substation, which would be required to supply the electrical needs of the area, in the event of failure of the normal substation is many miles to the east and also has limited capacity to provide energy in the event of a contingency. The service territory includes an Interstate 35 interchange which is prime area for economic growth. Located around the interchange is open land with available water and sewer. The service territory is envisioned to have a mix of small and large commercial along with residential development. As the load grows in this area, Dakota Electric will need to provide additional capacity, including feeders to supply the new development expected for this area. The timing for this growth is unknow, but a new substation is expected to be required within the next 5-10 years.

2. Project #1 – Advanced Grid Infrastructure (AGi) project

For Dakota Electric, the AGi project is designed to provide a foundation for the future. The project is designed to provide a platform that other functions can utilize to help the members and the overall operation of the distribution system. One of the benefits of the AGi project is the operational information gathered by the communicating digital meters to improve the integration of DER generation systems. The AGi project is considered by Dakota Electric as a non-wires project as it will provide Dakota Electric with greater knowledge of how the distribution system is performing and operating and support a more efficient construction and operation of the distribution system. The AGi project is Dakota Electric's focus to modernize the utility's grid and provide additional information to the members on how they use electrical energy.

The business case for the AGi project was submitted and rate recovery approved by the Commission in Docket E111/M-17-821.

3. Project #2 – Conversion and Rebuilding of the Lebanon Hills Substation Project

The Lebanon Hills project consists of the conversion of the existing Dakota Electric distribution substation, currently supplied by a 69kV transmission line to being supplied by a 115kV transmission line. This conversion was initiated by Great River Energy and was designed to allow GRE to retire multiple miles of its 69-kV lines in the area, result in a more reliable electric service for Dakota Electric, provide the framework for 115kV operations in the future, and provide the transmission infrastructure necessary to allow reconfiguration/ improvement of GRE Pilot Knob substation after these improvements are completed. The existing Pilot Knob substation 69 kV equipment is old and needs replacement, also the transmission line connections to the Pilot Knob substation are buried, difficult to maintain, have failed and require replacement and do not have the same capacity as the transmission lines they are connected to.

Great River Energy had two basic options available to them to continue to provide reliable service and to meet the growing electrical demands for the area. They could have replaced the existing 69kV infrastructure, including the underground transmission connections, the 69kV equipment at Pilot Knob and the substation transformers within Pilot Knob. Or they could work with Dakota Electric to convert the Lebanon Hills transformer to a 115kV source and build a short piece of 115kV transmission line. GRE worked with Dakota Electric and since Dakota Electric's existing equipment at Lebanon Hills was nearing 40 years of age, Dakota Electric was also interested in replacing its aging substation equipment. So, the conversion project was selected as the overall best value and lowest cost option. The extra benefit of the conversion project was the ability to retire several miles of 69kV transmission lines in the area.

The Dakota Electric portion of the project includes rebuilding the existing substations, replacing the existing substation switchgear and transformer, and rebuilding or reconnecting the existing substation feeders. The estimated cost for Dakota Electric's portion of the project is around $1.75 million dollars. The GRE portion of the project is to build new 115kV line to connect from the substation to the existing 115kV transmission line and construction of the 115kV portion of the substation. The budgeted cost for GRE's part of this project is around $2.9 million dollars.

No non-wired solutions were selected for a solution for this project. The project required a solution which would replace the Lebanon Hills substation with a 24/7 reliable supply to the existing feeders which are connected to the existing substation. Non-wired solutions which were identified for consideration required the existing Lebanon Hills substation to remain and the existing substation requires the 69kV transmission system to remain. Having the 69kV transmission continuing to supply the Yankee Doodle substation would not allow GRE to retire the 69 kV transmission lines and reconfigure the Pilot Knob substation. Because of this all the old Pilot Knob and Lebanon Hills substation equipment would be required to remain and require eventual replacement. Deferral of this substation equipment replacement using a non-wires solution was not considered a reasonable option due to the experienced failures of existing underground transmission lines at Pilot Knob and the advanced age of the rest of the substation equipment.

4. Project #3 Adding Capacity to Existing Dodd Park Substation (double ending the substation)

The load is increasing around the Dodd Park substation due to new residential and commercial development. The existing substation is supplying 6 feeders which are reaching the limit of their ability to supply the load in the area and still maintain the voltage levels. Additional feeders will be required to allow load to be transferred from the existing feeders. Also, there are no more circuit connections available in the Dodd Park substation, so a new substation switchgear will need to be installed to provide connections for the new circuits.

The following picture shows the substation from above. The building on the lower right side of the picture is the existing switchgear with the circuit exits and just to the left of the switchgear building is the substation transformer. The structures on the left side of the picture are the 115kV high side buss structures with in/out connections to the transmission line which flows through the substation. The open area in the upper right is space which has been prepared for a second transformer and switchgear. This project includes the addition of the second transformer and associated switchgear. The switchgear provides the breakers and connections for the new circuits connecting to this substation. This process is sometimes referred to as "double ending" the substation. The substation would then have two identical transformers and associated switchgear and would have spaces available to connect more feeders and have additional capacity.

Figure 5. Site Layout of Dodd Park Substation

The following are the requirements for supplying the feeders with electrical energy at the substation:

1) Must be able to interconnect with the new feeders planned to need to be installed.
2) Must provide breakers and associated protection for the new feeders.
3) Must be available 24/7.
4) Must provide at least 99.99% reliability.
5) Must meet the electrical demands of the loads supplied by the feeders at all times.
6) Upon failure, must be able to be repaired and restored to service in a short time frame, no longer than a 24-48 hours window.
7) Must be able to operate in the ambient environment.
8) Must be able to operate in sync with the Dakota Electric system when required.
9) Must be able to operate disconnected from the rest of the Dakota Electric system (but remain in electrical sync with the rest of the Dakota Electric system or be able to be synchronized with the Dakota Electric system to eliminate the need to outage member when switching between electrical sources.)
10) Must be able to maintain the distribution voltage within required tolerances.
11) Must be able to respond to sharp changes in the electrical demand. This could be due to storms and other emergency events.
12) Must be providing a 40-year solution.
13) Must be able to be modified to increase capacity as required.

14) Able to provide contingency capacity for adjacent portions of the Dakota Electric system during emergencies and in support of maintenance activities.

The cost to add the switchgear and transformer is estimated at $1.25-$1.5 million dollars. When analyzing potential non-wired solutions, the following issues were identified which tended to make those solutions uneconomical.

- If solar was used as a method to eliminate or delay the installation of the substation equipment. One still needs to install the substation switchgear for interconnection with the feeders, provide the feeder breakers and associated protection, therefore, the cost of the switchgear cannot be avoided. In addition, one of the largest costs for installing solar in this area, would be the cost of the land required to site the solar. All of the land around the substation is committed to residential or commercial development. It is unknown what the cost would actually be to purchase the land from a developer to be used for solar, or if the developers would even consider selling the land. It is known that the cost would be significant and permitting of a large solar farm is expected to be very difficult.
- Using energy storage to eliminate or delay the installation of the substation equipment, one would still need to install the substation switchgear for the interconnection of the feeders. The second issue would again be land as the amount of energy storage required would require more space than is available within the substation. There is a small amount of property adjacent to the substation, owned by the city, but it is unknown if that property would be available and at what price. If the land could be purchased from the City of Lakeville, the next issue would be permitting and the cost of the requirements to house the energy storage system.
- Option B of Project #4 analyzed an energy storage option to defer construction of a substation. The cost and risks of the energy storage option were found to be much greater than the cost of building a substation. The cost of even a 1 MW – 4 MWHr energy storage system would be over $1.5 million including siting and permitting, and this does not include the $500,000 cost for the required substation switchgear to interconnect with the feeders. Without a detailed analysis, it is clear that the $1.5 million to double end the existing substation using traditional solutions is much lower cost than an energy storage solution. The overall lowest cost and less risk option is the addition of the second transformer and switchgear. The substation site is fully prepped for the transformer and switchgear so other non-wired options are not close to being cost competitive.

5. Project #4 Siting and Construction of New Substation Near Elko-New Market

As new residential and commercial buildings are constructed in and around Elko-New Market Minnesota, Dakota Electric will need to provide services to these buildings. New feeders and distribution substation capacity to bring the electrical energy from the transmission system to the services is the historical method of providing electrical service. 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 would be required to supply the business and residential developments. This is assumed to be required for all the solutions analyzed. The analysis looks at the options available to Dakota Electric for providing a reliable source of electrical energy to these feeders supplying the businesses and homes.

As shown in Figure 6, there is an area east of the city of Elko-New Market which has a high growth potential. This area is presently supplied from the existing Lake Marion Substation which has some capacity to supply new loads in this area, but at some point, there will need to be more capacity to supply the growing load. The option of adding more feeders coming from Lake Marion along with increasing the Lake Marion capacity was considered. The problem with that solution is for loss of Lake Marion substation the remaining Castle Rock substation would not be able to supply the area. The cost to add feeders from both substations, Lake Marion and Castle Rock and also add more capacity at both substations was much greater cost than simply building a new substation in the growth area. This would provide the required capacity and also provide contingency support for both Lake Marion and Castle Rock substations.

Figure 6. Growth Potential of Lake Marion - Castle Rock Area

The project requirements for this project are the same as those listed above for Project #3.

<u>Load Growth Assumptions for the Options</u>

It is unknown how fast new load will be required to be served in the area. It is possible that the load could grow slowly as new business and residential developments are built, but it is also a very real possibility that one or two larger, megawatt sized new electrical loads could develop. Because of this any solution needs to be flexible to respond to and meet this unknown future load growth.

For the following analysis, there were two load growth scenarios developed. One is assuming a slower growth of the load in the area and the other is a faster growth scenario. Both of these growth scenarios are possible. Table 24 shows the peak load demand values which any option would need to supply.

Table 24. Growth Scenarios for Lake Marion – Castle Rock Area

Analysis Year	Slow Growth	Faster Growth
Year 1	1 MW	2 MW
Year 3	1.5 MW	4 MW
Year 5	2 MW	8 MW
Year 10	5 MW	12 MW
Year 15	10 MW	15 MW
Year 20	15 MW	20 MW
Year 30	25 MW	30 MW
Year 40	30 MW	40 MW

The following potential wired and non-wired options were identified for a high-level review.

a. Permitting and constructing a new 115kV substation capable of providing 25 MVA of capacity and able to easily expand that capacity as required in the future. (Traditional option.)
b. Permitting and developing a substation site, which is ready for future substation construction, but install an energy storage system to defer the substation construction costs.
c. Build a solar system to generate the energy and an associated energy storage system to provide 24/7 energy and deferring the substation construction for a longer period of time then Option B.
d. Installation of demand-side management to defer the substation construction for a few years.

<u>Summary of Assumption and Costs for all the Options Studied</u>

- The analysis is a high-level (not detailed) study of benefits, costs and risks to evaluate the relative benefits & costs of the different options.
- Land costs in the area are very expensive, the cost of purchasing a smaller site is assumed to be significantly more expensive than purchasing a larger acreage site.
- $250,000 per acre for 5 acres or less of land.
- $75,000 per acre for purchasing 40 or more acres of land.
- $400,000 to permit and develop a substation site (grading, roads, etc.).
- $500,000 For a 115kV to 12.5kV substation transformer.
- $500,000 for a substation switchgear.
- $500,000 for construction of a substation (Fence, high side, foundations, ground grid etc.).
- $250,000 for construction to double end an existing substation.

- $500,000 for connection to the transmission line.
- 4% annual interest rate for Net Present Value Calculations.
- Energy Storage System Costs.
    - $400 Per kW for energy storage infrastructure.
    - $350 Per kWhr for energy storage capacity.
    - 12% energy losses.
    - 12 years useful life for energy storage before refurbishing.
    - $10 / kW for ESS annual operating costs.
    - Energy storage operation is 80% coincident with Dakota Electric monthly peak.
- Solar Installation Costs
    - $1,800 per kW for solar system installation.
    - 8 acres of land per MW.
    - 1,400 MWHR annual production per MW of solar installation.
    - All solar generation is on-peak energy.

<u>Option A – Building a New 115 kV Substation</u>

A new substation would require a 3-4-acre site of land, requiring permitting, development of the site, interconnection with the transmission system and the purchase and installation of the substation equipment. Building the substation would meet all of the criteria listed above. The initial substation capacity would be at least 25 MW and the analysis includes doubling the capacity of the substation at 25 years. The cost of land in the area is relatively expensive as this is an area with a high potential for development. The costs shown below have been estimated on the high side for all of the categories.

The following is the cost for <u>both</u> the slow growth and the fast growth scenarios as the same substation can meet both growth scenarios.

Table 25. Option A - Building a New 115 kV Substation Cost Estimates

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acre)	$1,000,000	$1,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Transmission Interconnection	$500,000	$500,000
	Substation Equipment	$1,000,000	$1,000,000
	Substation Construction	$500,000	$500,000
Year 25	Increase the Substation Capacity		
	Substation Equipment	$1,000,000	$375,117
	Substation Construction	$250,000	$93,779
	Total Cost	**$4,650,000**	**$3,868,896**

Option A is using existing methods, is robust and provides a 24-hour, 7 days per week source of energy from the transmission system to the local distribution system. The option is proven to be a reliable solution and represents limited risk of not being able to supply the load.

The option provides enough capacity to handle all the expected load growth. 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 operate this standard equipment, under both normal and abnormal conditions. The Dakota Electric crews can quickly repair or replace any equipment used for this option.

<u>Option B – Deferring Building a New Substation Using Energy Storage</u>
This option is to develop a substation site, to be ready for construction of the substation when required, but to defer the purchasing and installation of the substation transformer, switchgear and transmission interconnection for a few years through the use of an energy storage system 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 that the energy storage system can be recharged each night to be ready to supply the peak load the next day.

A key assumption of this option is the energy storage system can be charged from the grid each evening and then have enough capacity to supply the new load requirements which are above what the existing electrical infrastructure can supply every day. This requires the new loads will have a very low demand during the evening hours and night time hours, to allow the energy storage device to be recharged. The energy storage system will also need to be able to cycle daily, which is known to be hard on the battery and reduce the life of the system. It is also assumed that for loss of a neighboring substation, there still is enough existing redundancy and capacity in the existing system to allow the energy storage device to be recharged that evening.

Since the load to be supplied by this device has not been built, the required capacity (MWHr) of the energy storage is not known. For this high-level analysis an assumption that the new load would be like a typical residential consumer was used. With this assumption, the load would peak during the morning and evenings with some dip in the electrical demands 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. If a commercial load was the driving force for the new capacity, that could require a greater energy capacity then was estimated for this high-level analysis.

There are additional potential benefits of the energy storage which were accounted for. The analysis gave credit to the energy storage system for reducing 80% of the peak demand charges over traditional power supply options. The analysis also gave credit to the energy storage system for charging the system using off-peak energy and then releasing the energy over on-peak hours. These benefits are somewhat off-set by the energy losses through charging and discharging the energy storage system. For the analysis the energy storage system was assumed to last for 12 years and no cost to renew the batteries were included within those 12 years. At 12 years the batteries were replaced and were expected to last another 12 years.

Table 26. Option B - Estimate Cost for Slow Growth of Load

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acres)	$1,000,000	$1,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (2 MW - 18 MWHr)	$7,100,000	$7,100,000
Year 5	Substation Equipment	$1,000,000	$821,927
	Substation Construction	$500,000	$410,964
	Transmission Interconnection	$500,000	$410,964
Year 25	Increase the Substation Capacity		
	Substation Equipment	$1,000,000	$375,117
	Substation Construction	$250,000	$93,779
	ESS Demand Benefits – Annual Operational Costs	-$4,704,691	-$3,679,489
	Total Cost	**$7,045,309**	**$6,933,261**

<u>Costs for Faster Growth Scenario</u>

The faster growth scenario, requires additional battery storage system capacity to be added in Year 3, but this provides twice the benefits over the 12-year life of the energy storage. The net present value (NPV) of the second energy storage system is less due to the system starting in Year 3, also the NPV of the second system is less than the first energy storage system.

Table 27. Option B - Estimate Cost for Fast Growth of the Load

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Acquire Land (3-4 acres)	$1,000,000	$1,000,000
	Permitting and Development of the Site	$400,000	$400,000
	Energy Storage (2 MW - 18 MWHr)	$7,100,000	$7,100,000
Year 3	Add Energy Storage Capacity		
	Additional (2MW - 18 MWHR)	$7,100,000	$6,311,874
Year 5	Substation Equipment	$1,000,000	$821,927
	Substation Construction	$500,000	$410,964
	Transmission Interconnection	$500,000	$410,964
Year 25	Increase the Substation Capacity		
	Substation Equipment	$1,000,000	$375,117
	Substation Construction	$250,000	$93,779
ESS #1	ESS Demand Benefits – Annual Operational Costs	-$4,704,691	-$3,679,489
ESS #2	ESS Demand Benefits – Annual Operational Costs	-$4,704,691	-$3,401,895
	Total Cost	**$9,440,618**	**$9,843,240**

Option B requires the energy storage system to have the capacity to carry the energy demand that is above the existing infrastructure capacity for most of the day, every day. For this option the amount of energy which could be unserved by the existing infrastructure could be large. Because of this the energy capacity of the ESS is significant and this increases the overall cost of this option. For the high-level analysis, detailed analysis of the load duration curves versus energy storage sizing was not done. The cost differences between the traditional solution at $3.9 million and this option at $9.8 million are great enough that additional analysis of this option was not warranted.

The risks with relying the energy storage system to supply the large amount of energy which could not be supplied by the existing infrastructure. With this single solution the overall risk of not being able to supply the load via the energy storage system is considerable. This option requires the existing electrical infrastructure to have spare capacity, every evening to allow charging of the energy storage system. This assumes the existing infrastructure is always available to support the charging of the energy storage system. Since the existing infrastructure is not always available, due to storms which damage the existing wires or traffic accidents which damage the poles supporting the wires, or outages due to animals etc. the risk of not having enough time every evening to recharge the energy storage system is considerable.

<u>Option C – Deferring a New Substation by Building a Solar System</u>
This option includes a solar energy system to provide the energy to meet the energy requirement of the new loads which are connected in the area and an energy storage system to provide energy during times when the solar is not available. The original thought was to use solar energy and energy storage to completely eliminate the construction of the substation, but as the energy and demand amounts continued to increase the overall costs of this option continued to escalate, especially for the fast growth scenario. Hence, 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 B, the sizing of the energy storage is difficult as the load profiles of the new loads are not known and will not be known until after they are built. High-level assumptions were made as to the energy and capacity requirements for the new loads. The energy storage will need to be sized to supply the energy requirements of the loads during periods when the solar panels are covered with snow, or there is extended cloud cover reducing the solar energy production. Because of this, the energy storage will need to be flexible to quickly allow for the addition of more capacity and both the solar and energy storage will need significant spare capacity to be available to serve new loads which can quickly occur.

Assumptions

- The solar system will last for 30 years without refurbishment.
- The energy storage sizing assumes:
    - Able to supply 50% of the peak load for 6 hours daily, also 25% of the peak load for 10 hours each evening.
    - In addition, the ESS must be sized to supply 90% of the load for at least two consecutive days, for loss of solar production due to snow or cloud cover.
- The production from the solar system is all produced on-peak and the costs are credited that full value.
- The Energy Storage is able to reduce the power supply demand charges by 90%.

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

Table 28. Option C – Estimate Cost for Slow Growth Scenario

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Acquire Land for Solar (80 acres)		
	Enough for 30 Years Capacity	$4,000,000	$4,000,000
	Build 2 MWs of Solar	$3,600,000	$3,600,000
	Energy Storage (2 MW - 18 MWHr)	$7,100,000	$7,100,000
Year 10	Build 3 MWs of Solar	$5,400,000	$4,438,406
	Energy Storage (3 MW - 18 MWHr)	$8,200,000	$6,739,802
Year 15	Build Substation		
	Use Solar Site Land for Substation	$0	$0
	Permitting and Development of the Site	$400,000	$222,106
	Transmission Interconnection	$500,000	$277,632
	Substation Equipment	$1,000,000	$555,265
	Substation Construction	$250,000	$138,816
	Solar Energy Production Benefits	-$13,776,000	-$7,185,267
ESS #1	ESS Demand Benefits – Annual Operational Costs	-$5,133,562	-$4,014,905
ESS #2	ESS Demand Benefits – Annual Operational Costs	-$5,133,562	-$4,014,905
	Total Cost	**$6,406,877**	**$11,856,951**

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, without depreciating them due to the time value of money the total amount of benefits is a much greater value. When present value of those benefits is calculated they are significantly reduced.

The following are the costs for the faster growth scenario.

Table 29. Option C - Estimate Cost or Fast Growth Scenario

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Acquire Land for Solar (120 acres)		
	Enough for 30 Years Capacity	$4,000,000	$4,000,000
	Build 2 MW of Solar	$3,600,000	$3,600,000
	Energy Storage (2 MW - 18 MWHr)	$7,100,000	$7,100,000
Year 3	Build 2 MW of Solar	$3,600,000	$3,200,387
	Add Energy Storage (2 MW - 18 MWHr)	$7,100,000	$6,311,874
Year 5	Build 4 MWs of Solar	$7,200,000	$5,917,875
	Energy Storage (4 MW - 20 MWHr)	$8,600,000	$7,068,573
Year 10	Build Substation		
	Use Solar Site Land for Substation	$0	$0
	Permitting and Development of the Site	$400,000	$222,106
	Transmission Interconnection	$500,000	$277,632
	Substation Equipment	$1,000,000	$555,265
	Substation Construction	$500,000	$277,632
	Solar Energy Production Benefits	-$24,640,000	-$13,444,984
ESS #1	ESS Demand Benefits - Operational Costs	-$5,133,562	-$4,014,905
ESS #2	ESS Demand Benefits - Operational Costs	-$5,133,562	-$4,014,905
	Total Cost	**$8,692,877**	**$17,056,552**

Option C is much like Option B as the energy capacity requirements are unknown for any new loads which will be requesting electrical supply from the Dakota Electric system. 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's analysis could easily be greater than what was used for the analysis in this option. There are concerns for what Dakota Electric would do if the solar system's output was limited for longer than a day or two. One possible cause of this concern could be a high wind storm damaging the panels and requiring weeks to months to repair. If this concern occurred there are no options for supplying energy that is not available. The only solution would be that some of the homes and businesses would need to be disconnected for periods of time and rotating blackouts would need to be utilized.

The traditional solution of building the substation is \$3.9 million dollars in present dollars as compared to \$11.8 and \$17 million dollars for the non-wires 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 is chosen over this option.

<u>Option D – Deferring New Substation with Demand-side Management</u>
This option would require Dakota Electric to work with new and existing loads to identify enough new load management loads that could be used to effectively reduce the system peak demands during times when the load in the area is greater than the existing infrastructure's capability. This would require developing new load management programs and most importantly the cooperation of the new members to allow the control of their electrical demand.

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 using a broad view across the system. When the need is to target specific areas and specific members during a short time period, there must be additional incentives applied to motivate the members to sign up. The assumption for this analysis is that it will cost \$150 per kW to get members to sign up for a specific load management control program.
- There is a general assumption that there is enough load that would work for load management programs to allow this option to occur. The assumption that a combination of traditional load management using load control receivers and behind the meter energy storage is used to achieve this load control.
- Cost per kW to install receiver-based load control is \$250/kW.
- Cost per kW to install behind the meter energy storage is \$1,200/kW (assuming 4 kWhr per kW).

The following costs are assuming slow growth. This option would not be practical for the fast growth scenario, as the loads during the evening would be greater than the existing system could support and 24-hour duration load control is not an option.

Table 30. Option D - Cost Estimate for Slow Growth Scenario

Project Year	Description	Cost (2019 Dollars)	Present Value @ 4% Rate
Year 1	Cost of Incentives for Members	$300,000	$300,000
	Cost of Energy Storage Systems (1.5 MW)	$1,800,000	$1,800,000
	Cost of Receiver Controls (500 kW)	$125,000	$125,000
Year 5	Acquire Land (3-4 acres)	$1,000,000	$821,927
	Permitting and Development of the Site	$400,000	$328,771
	Substation Equipment	$1,000,000	$821,927
	Substation Construction	$500,000	$410,964
	Transmission Interconnection	$500,000	$410,964
Year 25	Increase the Substation Capacity		
	Substation Equipment	$1,000,000	$375,117
	Substation Construction	$250,000	$93,779
	Total Cost	**$6,875,000**	**$5,488,448**

One of the major differences between this option and Options B and C is that the load management is sized to the actual loads as they are applied. Since the load management is installed at the member's home or business, the overall cost of the energy storage is lower. The assumption for this option was a shorter time frame needed energy storage. The actual costs of the energy storage solution for this option could easily be much greater. Another issue with this option, versus Options B and C, is that Dakota Electric cannot prebuild the energy storage to ensure that the load level on the existing infrastructure is reduced to below the available capacity level. Any installation must wait for the load to be built and then convince the member to install load management or energy storage. This is a risk of non-supply for the member's electrical needs.

One of the interesting issues with placing energy storage behind-the-meter is determining who will be paying for the energy losses which are associated with the charging and discharging of the energy storage system. Other cost issues arise with BTM energy storage revolving around obtaining access into the members' home to maintain energy storage systems. Access to members' homes typically requires scheduled afterhours visits. This option is again a higher risk of non-supply at a higher cost. The Demand-side Management option is the lowest cost non-wires solution, but it is still $5.5 million versus $3.9 million for the traditional solution.

All of the non-wired solutions identified by Dakota Electric for possible utilization instead of the traditional installation of a substation are shown to be more costly and have a much greater risk of not being able to meet the energy demands of the member's load. One of the key responsibilities which is driving Dakota Electric is the requirement to serve and the member's expectation of reliable electrical service. In addition to higher costs, the risk to reliability is one of the key reasons utility engineers have difficulty choosing non-wired solutions.

6. 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 is in the initial process of researching for types of projects which would lend themselves to non-traditional solutions. While Dakota Electric has considerable experience in applying demand-side management to reduce billing demands and to reduce or delay system capacity additions, the Cooperative has limited experience with applying other non-wired solutions for eliminating or delaying system additions or improvement. As part of this Integrated Distribution Planning process Dakota Electric has taken the approach to ask the vendors how they would propose to solve some traditional distribution planning problems. Information on how Dakota Electric reached out to vendors to gather information about potential non-wired solutions for specific traditional distribution planning problems is presented in the Non-Wired Solution Analysis area of this section.

7. 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).

At this stage with Dakota Electric's current knowledge level of non-traditional solutions timelines to consider alternatives for project types would be rather lengthy. Most likely Dakota Electric would release a Request for Proposal (RFP) requesting a design-build solution for a specific project or problem that needs resolving. A typical timeline for this approach would be approximately 6-12 months for the selection of a solution. Actual permitting and construction time fames would depend upon the solution and the location of the project. As Dakota Electric's experience with evaluated non-traditional solutions increases, it is expected the timeline needs for evaluation would decrease.

8. 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 RFI process Dakota Electric had for non-wired solutions, it became apparent the non-traditional solutions do not necessarily best compete at a specific cost threshold. While economies of scale were important, the type and capacity size of problem played a larger role in determining a non-traditional projects cost viability compared to traditional distribution projects.

9. 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 RFI exercise was that NWS are not a global solution to every distribution system problem. However, there are specific scenarios in which NWS could be considered in lieu of traditional building of distribution circuits. The specific scenarios for NWS are not necessarily tied to a cost level of an infrastructure project. Often, the scenarios NWS would be considered for are related to step change needs in available capacity for an area that is underserved for short durations that occur infrequently.

Non-wired solutions have the potential of delaying 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-wired solutions further in these situations. To further increase the value of non-wired solutions would be moved and reused in a different location. Mentioned in the DER Non-Wired Solution Analysis section is the concept of a mobile solution. The mobile solution scenario was presented to address abnormal configuration, short term, hourly capacity needs. However, the idea of a mobile non-wired solution has grounds to provide great value to an utility when coupled with delaying capital investment.

The following are the key criteria that are involved with comparing energy supply solutions.

- Duration of the need to supply energy
- Frequency of the need to supply energy
- Cost
- Reliability; especially risk of not be able to supply the energy when required
- Maintenance requirements
- Annual operating costs
- Additional benefits

10. Non-Wired Solution RFI Analysis

As part of the IDP process, Dakota Electric desired to expand their knowledge base with NWS for use in future distribution planning purposes. The goal is to develop a set of solutions which could be applied to solve specific traditional distribution planning issues. To this point, Dakota Electric released a Request for Information, (RFI), in mid-February 2019 to various vendors[1], requesting NWS for typical distribution system planning issues commonly encountered by Dakota Electric. A copy of the RFI sent to the various vendors is attached to this report as *Appendix C – Non-Wires Solution RFI*.

Dakota Electric's RFI, contained four problem statement scenarios which were typical of common issues that arise during the distribution planning process. The selection of the four problem statements, including identifying distribution planning issues which were believed to provide non-wired solutions the best opportunity of solving versus the normal wired solution. Table 31 is a summary of the four problem statements and the number of responses received for each the scenarios.

Table 31. RFI Responses by Problem Statement

Problem Statement (Scenario)	Problem Summary	Traditional Solution	Number of NWS Proposals Received
A – Limited Main Circuit Capacity	Growth causing circuit overloads for short periods of time	Upgrade or add an additional circuit	6
B – Serving New Load	New residential development where limited distribution facilities exist	Addition of new circuit(s)	3
C – Contingency Support	During abnormal N-1 conditions, contingency source is overloaded	Upgrade contingency circuits, contingency substations	3
D – Mobile Solution	Mobile generation source for areas where contingency options do not exist	Fossil fuel generator mounted on a flatbed	1

Respondents to the RFI were asked to provide details on their proposed NWS, such as solution useful life, estimated install costs, availability of the solution to operate, estimated operations

[1] Dakota Electric directly sent the RFI to 35 different vendors who have designed and/or installed NWS in North America.

and maintenance costs and end-of-life removal. Many vendors commented that Dakota Electric's problem statements were sized smaller than typical projects they were designed for. Those vendors that contacted Dakota Electric about the problem statements stated their thresholds for NWS projects was 2 MW.

Dakota Electric reached out to 25 vendors with the RFI. Dakota Electric received responses from 5 of those vendors. One of the vendors submitted two separate responses. STAR Energy, a consultant for Dakota Electric, reviewed all responses with specific Respondents that provided potentially viable NWS projects for one or more of the problem statements. A few of the Respondent's NWS projects were not included in this report, as Dakota Electric deemed the information provided by the Respondent either lacking or implausible.

A summary of the different NWS projects for each of the problem statements are listed in the following sections. It is important to note that all Respondents were asked to provide budgetary costs estimates. Dakota Electric expects that in a formal RFP, the NWS costs would be 10 – 20% lower than indicated by the RFI responses.

11. Problem Statement A – Limited Main Circuit Capacity

Problem Statement A – Limited Main Circuit Capacity

Dakota Electric has a specific area where the existing distribution electric infrastructure is not robust enough to supply the entire peak electrical needs of a growing electrical demand. During times of peak demand, the voltage cannot be maintained within acceptable power quality limits. Currently, peak periods last for 1 - 2 hours, is around 200 - 500 kW of excess demand and occur only 5 – 10 times per year. Growth in the amount of the underserved load is occurring and the duration and frequency of the peak load is increasing.

Scenario A1 *– Assume the Problem Statement A is occurring in a suburban area, with projected 2 - 3% annual growth for five years. Land availability is scarce and prices for available land is very expensive, (i.e., sold by the square foot). After five years the underserved load is forecasted to increase from 200 – 500 kW and be 1 - 2 MW. It could last 4 - 5 hours, and occur 5 - 10 times per month during the summer months and 1 - 3 times per month during the other months, specifically winter months.*

The typical, traditional wired solution for Scenario A1 would be to rebuild the main circuits with a larger conductor or to build an additional circuit into the area.

Scenario A2 *– Assume the Problem Statement A is occurring in a rural area, with slow growth over a long period of time. Annual growth is expected at 0.1% for many years. Land availability and cost is reasonable, (i.e., sold by the acre and is normally converted from agricultural fields). After five years the underserved load is expected to change from 200 – 500 kW and be 400 - 600 kW and last for 3 - 5 hours and occur 10 - 15 times per year, mainly during summer months.*

Problem Statement A described a common distribution system growth issue where Dakota Electric would normally evaluate rebuilding the existing main circuits to a specific growth area or look to bring in an additional circuit to increase the capacity available in an area. The NWS proposals Dakota Electric received for this problem statement ranged from solar plus storage projects to combined heat and power installations.

Problem Statement A also had multiple responses of NWS utilizing energy storage systems made up of batteries of different sizes and technologies. The proposed batteries would be interconnected directly to the distribution grid and would be charged by the grid. It was pointed out that battery storage was very modular and had a small footprint. The battery storage NWS was also scalable for both Scenario 1 and 2 of Problem Statement A. NWS battery storage is grouped together as Project A in Table 32.

Another response to Problem Statement A incorporated both a photo voltaic system with an energy storage system. The 500 kW - 800 kW PV system resulted in the energy storage system significantly sized smaller than proposed by Respondents grouped as Project A. As much of the information regarding the batteries proposed to be used in conjunction with the PV system is similar to information listed in Project A, only the PV system information is listed in Table 32 as Project B.

Another response was a NWS that proposed using a mixture of Combined Heat and Power (CHP), ESS and DSM tools. For Scenario A1, the NWS recommended storage batteries used behind the meter (BTM) in conjunction with a robust DSM program and large CHP installed behind large commercial and industrial accounts. For Scenario 2, the NWS recommended storage batteries and CHP plants installed on the utility side of the meter. In this NWS, the amount of load the DSM program was to control was not identified. This NWS also did not address in any detail how the excess heat from the CHP system would be utilized. All descriptions in the RFI seemed to refer to simply a reciprocating natural gas engine. For the analysis, Dakota Electric is referring to the CHP as a natural gas engine.

As the information provided about the batteries, both located behind-the-meter and front-of-meter, was similar to the information summarized in Project A, the natural gas engine and the DSM portion are listed in Table 32 as Project C and D.

Table 32. Problem Statement A - RFI Responses

	Project A – ESS	Project B – PV System	Project C – Natural Gas Engine	Project D – DSM	Traditional
Installation					
Procurement, Design and Installation	6 - 8 months	7 months	10 - 11 months	3 - 6 months	3 - 6 months
Operations and Maintenance					
Maintenance Requirements	Annual or quarterly visual inspections	Weekly remote confirmation. Annually visual inspections	Every 2,000 operating hours	Remote confirmation periodically	3 - 5 years visual inspection
Duration of Maintenance Outages	8 - 24 hours annually	1 hour annually	1 - 3 days	None	N/A
Environmental Issues	None. Recycling program exist.	None	None	None	None
Performance					
Expected Up-time	95% - 98%	99%	94%	N/A	99.9%
Expected Useful Life	10 - 20 years	25 years	20 years	15 - 20 years	40 - 60 years
Costs					
Budgetary Cost for Utility Ownership	$300 - $500 per kWhr	$1,800 - $2,500 per kW	$2,500 - $4,500 per kW	$275 per receiver	$150,000 - $200,000 per mile
Estimated Annual Operating Costs	$10 - $50 per kW	$7 - $9 per kW	$0.03 per kWhr	N/A	$1,000 per mile

For the comparison analysis of this scenario, Dakota Electric is assuming land is available and affordable for the proposed NWS. It was also assumed the NWS permitting would be comparable to the permitting cost and time duration as a traditional solution. For the ESS solution, Dakota Electric did not include the cost estimate for utility ownership for BTM ESS. For a 300 kWhr home ESS, the cost estimate was $1,200 per kWhr which skewed the cost range in the table. It's also important to note that decommissioning costs are not included for any of the solutions listed in the table. The RFI responses lacked in sufficient detail to include decommissioning costs in this analysis.

<u>Installation</u>
From the responses Dakota Electric has received, the installation of utility-scale and BTM batteries takes between 6 - 8 months for procurement, design and installation. Installation of utility scale battery systems require a relatively small footprint as many of the battery designs are in containers approximately 10 feet x 60 feet. The time frames provided by the vendors for installation of utility scale energy storage systems, appears to not include the time required for permitting and land acquisition. The time frame provided by the vendors for behind the meter energy storage, assumes there are members willing to allow the installation of energy storage systems in their homes and businesses. The time fame to identify all of those locations and coordinate the installation process for each of the homes and businesses, appears to be in addition to the time frames provided by the vendors.

Including a PV system with the batteries does increase the footprint required over a PV only system. An additional 75,000 square feet for 500 kW of energy storage was estimated by the vendor. The required footprint for the PV system could be located on a rooftop of a commercial building(s) relieving the need for available property. The PV system could also be designed, procured and installed within 6 - 8 months assuming available space is found for the installation and minimal permitting and member coordination is required.

Design, procurement and installation of a 2 - 3 MW natural gas engine system would take between 10 - 11 months. With this NWS the required footprint is still relatively small with the gas-fired reciprocating engines and the heat recovery equipment located in approximately 8,000 - 10,000 square foot space. The time frame provided by the vendors for the natural gas engine solution assumes there is space available and easily acquired. No additional time for permitting and site acquisition appears to have been added to the vendor's time frame. Additionally, the timeframe to identify a service that can utilize the heat production was not included in the RFI response.

The DSM aspect incorporated with Project C would have minor design, procurement and installation durations. As Dakota Electric already has a robust DSM program and significant experience with DSM the time frame to start a DSM solution is minimal. With an existing control system and an inventory of DSM receivers, Dakota Electric could quickly control additional loads. Dakota Electric already has a majority of the controllable loads already under load management, it is unclear where additional load to be controlled would be found. Also, the time frame to acquire additional load management load in a specific area with loads which are not presently under control would appear to be a challenge and a lengthy process. The 3-6 months estimate provided by the vendor assumes that the services and loads have been identified and signed up prior to the start of the installation time frame.

A traditional upgrade of the existing distribution circuits would take approximately 6 months for design, permitting, procurement and installation. No additional space requirements are needed if existing distribution circuits are upgraded for additional capacity. Very little concern exists with meeting timeframe requirement when using the traditional solution.

Operation and Maintenance

Required maintenance for the NWS incorporating batteries was minimal, according to the vendors responses. For the utility sized battery systems, the maintenance revolved around quarterly checks of the HVAC and fire suppression systems. The batteries themselves were mainly checked either visually or remotely for their efficiency on charging and discharging. All Respondents did recommend an annual site visit for an inspection of all connections. Required outages for maintenance of the NWS ranges between 8 - 24 hours annually.

Dakota Electric noted for the ESS solution warrantees of the batteries often were less than 15 years. The ESS solution required a rejuvenation aspect to replace the batteries below a specific efficiency level at the 10 - 15 year mark for the ESS solution to have an expected life comparable to other NWS years.

The PV system also had relatively low requirement maintenance with much of the weekly maintenance checks performed remotely to confirm production levels. Annually the PV system was to be visually inspected. Required outages of the PV system for maintenance was approximately one hour annually. No discussion about snow or dust build-up removal from the PV panels was discussed by any of the vendors.

For the natural gas engine system, the maintenance level increased slightly to include oil and filter changes along with other mechanical maintenance items that would be performed on a set operating hour schedule. Major overhaul of the engines was also recommended at specific operating hours ranges. Outages of the natural gas engine system due to maintenance ranged from 1 day for oil changes and spark plug change to one week for major overhauls of the reciprocating engines. These maintenance outages could be easily scheduled for periods where the electrical demand is reduced.

For the DSM aspect of Project C, very minimal annual maintenance is required. Provided the DSM receivers are coupled with a MDMS, remote confirmation of the operation status of the DSM received, can be performed during control events. Periodic replacement of failed DSM receivers would be required as they are identified by the MDMS. Dakota Electric would also need to dedicate labor to review the MDMS data and create service orders for the crews to inspect DSM receivers which were suspected of not operating correctly. Other maintenance would be related to the communication pathway of the DSM and MDMS systems.

The traditional distribution circuit upgrade, required maintenance, is relatively minor with inspection of connections occurring every 3 - 5 years. Overhead construction of the electrical circuit would require periodic vegetation trimming costs. Underground construction of the electrical circuit does require involvement with Gopher State One-call locating service. This would lead to Dakota Electric incurring some periodic costs.

<u>Decommissioning</u>

Dakota Electric was told by the Respondents that all proposed NWS do not have an environmental impact upon decommissioning. Many manufactures of batteries for energy storage systems, have a recycling program to take back spent batteries. With the modular design of the batteries, returning the site back to green field would simply be removal of concrete pads and other electrical switchgear. No discussion of decommission costs were mentioned or included in the estimated ownership costs.

The PV system also had relatively simple decommissioning steps of removal of panels and the racking system. Indications from the Respondents stated that the scrap material should cover decommissioning costs to return the site back to green field or normal rooftop setting. No specific amounts of decommissioning costs were included in the estimated costs.

The natural gas engine system did have approximately $500,000 - $750,000 predicted in decommissioning costs, though it is expected there would be some salvage value of the equipment to help offset these costs.

The DSM system that was to combine the CHP system and BTM energy storage systems, would have decommissioning costs mainly labor related with the removal of the DSM receiver and the energy storage system located at individual service locations. Salvage value of the DSM receivers are expected to be zero. The decommissioning costs were not included in the estimated costs for these systems.

<u>Performance</u>

All of the NWS projects estimated up-time to be in the 90% and above range. Utility scale batteries had expected up-times of 95% - 98%. BTM batteries expect up-time was somewhat lower at 90%. The PV system up-time was estimated by the vendors at 99% provided the conditions were available for production to occur, (sunlight was occurring). For the PV system there was no provisions for when the sun was not available and/or the panels were covered with snow. The natural gas engine system had a 94% expected up-time.

The expected useful life of the different NWS varied between 10 - 25 years. In general, batteries for energy storage system were guaranteed for 10 years at 80% capacity with an expected useful life of 15 years. PV systems were designed to have an expected life of 25 years. Similarly, the CHP system was expected to have an expected useful life of 20 years. It has been Dakota Electric's experience that DSM receivers have a 15 to 20-year expected useful life prior to replacement occurring. In comparison, a new electrical circuit is expected to have a useful life of 40 - 60 years.

All of the NWS could also be rejuvenated with replacement of certain components. For energy storage solutions, the batteries could be swapped out as the charging and discharging levels decreased with new battery modules. Estimated replacement costs were expected at approximately 60% of the original installation costs for the energy storage solutions.

The PV system could be rejuvenated with replacement panels and inverters. Rejuvenation costs were projected at 80% of the original NWS installation costs.

<u>Costs</u>

As Dakota Electric only released a RFI and informed Respondents that their submittals could not be held confidential, the cost figures received back from the Respondents were expected to be higher than costs that would be received in a formal RFP. The discussion of initial and ongoing costs shown in Table 33 and Table 34 are to be considered high level estimates for comparison.

In Table 33 the costs are assumed for an urban area. The following assumptions have been made:

- 700 kW of NWS (1,400 kWhr) is required upon installation to address the initial growth (for 2 hours)
- At two and four years, 700 kW (1,400 kWhr) of additional capacity is added. Additional kWhr for ESS may be required but was not included in this cost analysis for simplification.
- The cost to replace the batteries at 15 years is assumed at 60% of the initial costs.
- ESS energy loss is assumed to be 5-10% of the rating of the ESS unit under normal operation. For this analysis 5% of the kWhr rating was used. The cost of the energy for the calculation of losses is $0.07 per kWhr.
- A diversified average demand reduction of 0.5 kW per DSM receiver is assumed.
- A 1% annual failure rate for DSM receivers is estimated.
- DSM replacement costs are assumed to be $275 per unit including labor.
- A three mile, three-phase distribution line was installed for the traditional solution.
- Traditional distribution line on Dakota Electric system has a 2.5% line loss.

Table 33. Estimate Costs for Problem Statement A - Urban Area

	Project A – ESS	Project B – PV System	Project C – Natural Gas Engine	Project D – DSM	Traditional
Initial Costs (unit)	$300 - $500 per kWhr	$1,800 - $2,500 per kW	$2,500 - $4,500 per kW	$275 per receiver	$150,000 - $200,000 per mile
Initial Cost	$420,000 - $700,000	$1.26M - $1.75M	$5.3M - $9.4M	$385,000	$450,000 - $600,000
At 2 years	$420,000 - $700,000	$1.26M - $1,75M	-0-	$385,000	-0-
At 4 years	$420,000 - $700,000	$1.26M - $1,75M	-0-	$385,000	-0-
Rejuvenation Costs at 15 years	$756,000- $1.3M	Limited	Limited	$525,000	-0-
Annual Energy Loss	$250,000	Limited	Limited	None	$100
Annual O&M Costs	$10 - $50 per kW	$7 - $9 per kW	$0.03 per kWhr	$6,500	$1,000 per mile
25-year Total Costs	>$8.8 million	>$4 million	>$5.6 million	>1.8 million	>$0.6 million

In Table 34 the costs are assumed for a rural area. The following assumptions have been made:

- 600 kW of NWS capacity is required to handle the initial demand (2 hours or 1,200 kWhr).
- After 5 years the duration of the peak has increased and an additional 1,200 kWhr needs to be added to the ESS.
- The cost to replace the batteries at 15 years is assumed at 60% of the initial costs.
- ESS energy loss is assumed to be 5-10% of the rating of the ESS unit under normal operation. For this analysis 5% of the kWhr rating was used. The cost of the energy for the calculation of losses is $0.07 per kWhr.
- A diversified average demand reduction of 0.5 kw per DSM receiver is assumed.
- A 1% annual failure rate for DSM receivers is estimated.
- DSM replacement costs are assumed to be $275 per unit including labor.
- A three mile, three-phase distribution line was installed for the traditional solution.
- Traditional distribution line on Dakota Electric system has a 2.5% line loss.

Table 34. Estimated Costs for Problem Statement A - Rural Area

	Project A – ESS	Project B – PV System	Project C – Natural Gas Engine	Project D – DSM	Traditional
Initial Costs (unit)	$300 - $500 per kWhr	$1,800 - $2,500 per kW	$2,500 - $4,500 per kW	$275 per receiver	$150,000 - $200,000 per mile
Initial Cost	$360,000 - $600,000	$1.08M - $1.5M	$5.3M - $9.4M	$330,000	$450,000 - $600,000
At 5 years	$360,000 - $600,000	$1.08M - $1.5M	-0-	$330,000	-0-
Rejuvenation Costs at 15 Years	$432,000 - $720,000	Limited	Limited	$300,000	-0-
Annual Energy Loss	$150,000	Limited	Limited	None	$100
Annual O&M Costs	$10 - $50 per kW	$7 - $9 per kW	$0.03 per kWhr	$6,500	$1,000 per mile
25-year Total Costs	>$5.2 million	>$2.4 million	>$5.6 million	>$1.1 million	>$0.6 million

In comparison, the traditional rebuilding of the existing circuit would be approximately $200,000 per mile. A normal worst-case assumption that an entire circuit would need to be added or rebuilt could be used. In general, Dakota Electric's main line three-phase circuits are averaging three miles long from a substation. A realistic, worse case situation estimate initial cost of the traditional solution of this planning scenario would be $600,000.

For the urban environment scenario all of the non-wired solutions are significantly more expensive than the traditional wired solution. The cost differences are so great that it does not appear to be a reasonable non-wired solution for this distribution planning scenario in the urban areas.

For the rural environment scenario, where the load growth is expected to be slower and smaller in magnitude, the differences between the wired and non-wired solutions is much less. Assumptions about lineally scaling the vendors NWS costs for this smaller application and assuming the lowest costs may not be realistic. For purposes of sorting through possible solutions these assumptions were made:

- The energy storage solution is still a significantly greater cost than a traditional wired solution for the rural scenario.
- The PV solution, without including energy storage, is closer to the traditional cost of adding a new electrical circuit. However, since the system peak demand is not coincident with the output of the PV system, energy storage must be included in the NWS which results in total costs that are then much greater than the traditional wired solution.
- Only the DSM solution estimated costs are lower than the traditional wired solution.

Dakota Electric has a robust DSM program that currently has participation rates of over 50%. DSM solutions may be the most cost-effective solution to this problem statement. However, finding enough loads to participate in DSM is a limiting factor in the success of this NWS.

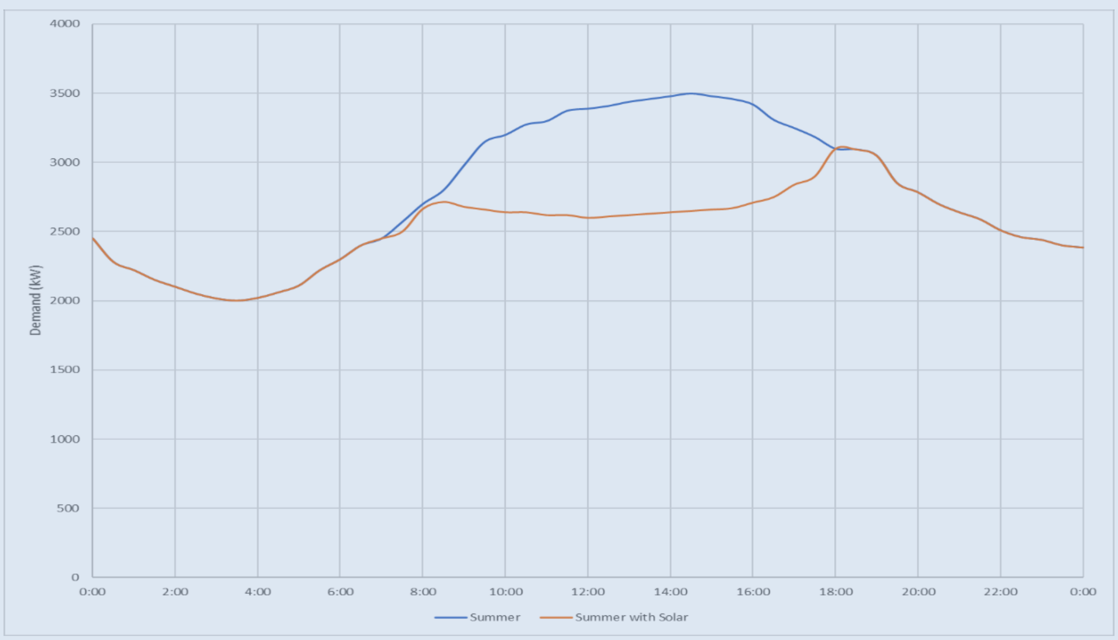
12. Problem Statement B – Serving New Load

Problem Statement B – Serving New Load

Dakota Electric has a new residential development for a specific area. The existing electrical infrastructure is not sufficient to supply the majority of the additional new load. Possible solution(s) need to be redundant and robust to ensure a reliability supply of electricity. Possible solutions(s) must also allow for portions of the solution to be out of service for maintenance.

For Problem Statement B, assume the new load is residential and has a daily minimum load level around 2.0 MW and a peak demand of 3.5 MW. The initial daily summer load curve is expected to be similar to the blue line on the graph shown in Figure 1. Due to solar interests by potential new load(s) in the area, there exists the possibility that some of the buildings within the development may install solar. Given significant penetration of solar installations, the daily summer load curve is expected to be similar to the orange line on the graph shown in Figure 1.

Figure 1. Problem Statement B – Expected Load Curves



Problem Statement B described another common distribution system growth issue where Dakota Electric would normally evaluate building new distribution circuit(s) and substations to the specific growth area. For this Problem Statement, Dakota Electric did want Respondents to incorporate the knowledge that the members could adopt behind-the-meter solar in the future, but Dakota Electric is required to provide the member's total electrical needs currently.

The NWS proposals Dakota Electric received for this problem statement where similar to solutions suggested in Problem Statement A. Utility-owned ESS, PV system with utility-owned ESS and a 4 MW natural gas turbine combined with a micro grid were proposed as possible NWS. To evaluate the different components Project E is considered a 4 MW natural gas generator located either behind-the-meter or front-of-the-meter. Much of the information with the natural gas generator was similar to the CHS/natural gas engine system proposed for Problem Statement A.

For the installation times frames suggested by the vendors, many of the same issues remain with acquiring land, permitting the NWS and/or identifying members which would be willing to have Dakota Electric install equipment within their home or business. It is unknown how much time and incentives would be required to get members to allow this intrusion into their homes or businesses.

The traditional solution Dakota Electric would use is to build new circuits to the new development area. Dependent on other situations, it is also possible that a substation would need to be upgraded to handle the projected capacity. In addition, Dakota Electric would want to ensure N-1 contingency to the new load area. In the worst-case, this could result in dual circuits to the new load area.

Table 35. Problem Statement B - RFI Responses

	Project A – ESS	**Project B - PV System**	**Project E - Natural Gas Generator**	**Traditional (Line Only)**	**Traditional (Substation)**
Installation					
Procurement, Design and Installation	6 - 8 months	7 months	10 - 11 months	3 - 12 months	12 - 36 months
Operations and Maintenance					
Maintenance Requirements	Annual or quarterly visual inspections	Weekly remote confirmation. Annually visual inspections	Every 2,000 operating hours	3 - 5 years visual inspection	Monthly visual inspection
Duration of Maintenance Outages	8 - 24 hours annually	1 hour annually	1 - 3 days	N/A	N/A
Environmental Issues	None. Recycling program exist.	None	None	None	None
Performance					
Expected Up-time	95% - 98%	99%	94%	99.9%	99.9%
Expected Useful Life	15 - 20 years	25 years	20 years	40 - 60 years	40 - 60 years
Costs					
Budgetary Cost for Utility Ownership	\$300 - \$500 per kWhr	\$1,800 - \$2,500 per kW	\$2,500 - \$3,500 per kW	\$150,000 - \$500,00 per mile	\$1.5M - \$2M
Estimated Annual Operating Costs	\$10 - \$50 per kW	\$7 - \$9 per kW	\$0.03 per kWhr	\$1,000 per mile	\$2,000

As stated in Problem Statement A, for the comparison analysis of this scenario, Dakota Electric is assuming land is available and affordable for the proposed NWS and the traditional substation. It was also assumed the NWS permitting would be comparable to the permitting cost and time duration as the traditional solution. Decommissioning costs are not included for any of the solutions listed in the table. The RFI responses lacked in sufficient detail to include decommissioning costs in this analysis.

It's important to point out that building a distribution substation requires a more significant amount of design and procurement time compared to the other solutions listed. Procurement for substation transformer takes between 12 – 30 months to acquire. Requests for an interconnection to the transmission system also require at a minimum a year of notice prior to the substation being built. If transmission needs to be extended to a new distribution substation, design, procurement and installation time requirements are expected in the 2 – 5 year range.

In Table 36 the costs are assumed for a suburban area. The following assumptions have been made:

Assumptions

- 4 MW of NWS capacity is required to handle the initial demand (2 hours or 8,000 kWhr).
- The cost to replace the batteries at 15 years is assumed at 60% of the initial costs.
- ESS energy loss is assumed to be 5-10% of the rating of the ESS unit under normal operation. For this analysis 5% of the kWhr rating was used. The cost of the energy for the calculation of losses is $0.07 per kWhr.
- A three mile, three-phase distribution line was installed for the traditional solution.
- Traditional distribution line on Dakota Electric system has a 2.5% line loss.
- The new substation is located next to an existing transmission line with sufficient capacity available.

Table 36. Estimated Costs for Problem Statement B - Suburban Area

	Project A – ESS	Project B - PV System	Project E - Natural Gas Generator	Traditional (Line Only)	Traditional (Substation & Line)
Initial Costs (unit)	$300 - $500 per kWhr	$1,800 - $2,500 per kW	$2,500 - $4,500 per kW	$150,000 - $200,000 per mile	$150,000 - $200,000 per mile; $2M substation
Initial Cost	$2.4M - $4.0M	$7.2M - $10.0M	$10M - $18M	$450,000 - $600,000	$2.5M
Rejuvenation Costs at 15 years	$2.88M - $4.8M	Limited	Limited	-0-	-0-
Annual Energy Loss	$250,000	Limited	Limited	$100	$100
Annual O&M Costs	$10 - $50 per kW	$7 - $9 per kW	$0.03 per kWhr	$1,000 per mile	$1,000 per mile
25-year Total Costs	>$10 million	>$7.2 million	>$10 million	>$0.6 million	>$2.6 million

Problem Statement B starts to lay the foundation where NWS start to compete on a cost-benefit basis. Depending on how significant the infrastructure cost to meet the N-1 contingency level[2] is, incorporating a PV system is worth examining especially when the new load area is located a distance away from Dakota Electric's existing distribution and/or substation facilities. The PV System coupled with the traditional wired solution of extending a new circuit has the potential to delay the need for a new substation for a period of time. The delay in the substation infrastructure is a financial benefit for Dakota Electric to consider when evaluating the non-tradition solutions to a load growth issue.

[2] N-1 contingency having a redundant method of providing electric service to an area if a single piece of equipment failed. For example, a substation taken out of service requires a neighboring substation(s) to have the capacity to serve the load of the out-of-service substation.

13. Problem Statement C – Contingency Support

Problem Statement C – Contingency Support

Dakota Electric has a portion of its service territory in which the existing distribution system can adequately serve the existing load under normal operating conditions. During peak loading conditions, when the distribution system is in abnormal operating conditions, (i.e., failed or damage portions of the distribution system resulting in reconfiguration of the distribution system), this portion of the electrical load cannot be adequately served as contingency configuration options for the distribution system and do not provide enough capacity to serve the entire load. Abnormal operating conditions could last up to seven consecutive days.

Scenario C1 *– Assume amount of underserved load is 500 kW and the duration of that peak load is 4 - 6 hours per day, during the abnormal operating conditions. Past experience has shown that these abnormal operating conditions have a low to medium probability of occurring, (occurrence may happen once in a seven-year span.)*

Scenario C2 *– Assume amount of underserved load is 1 - 2 MW and the duration of that peak load is 6 - 8 hours per day, during the abnormal operating conditions. Past experience has shown that these abnormal operating conditions have a fairly high probability of occurring, (occurrence may happen once every two years.)*

Problem Statement C described a resiliency distribution system problem where Dakota Electric would normally evaluate upgrading existing distribution circuits and/or upgrading neighboring substations in the area. Only one NWS proposal was received for this problem statement suggesting either a 500 kW - 2 MW battery system or a 500 kW - 2 MW fossil fuel reciprocating generator.

Dakota Electric's traditional solution would be to rebuild the existing contingency feeds to address the expected peak load. Dakota Electric currently tracks the amount of load that can be shed in specific areas and would utilize DMS load shedding to assist with alleviating the load requirements on the contingency source. Dakota Electric would most likely rebuild the contingency feeder to address Scenario C2, where the occurrence of the abnormal condition is more frequent and the capacity unserved is greater. It is possible that Dakota Electric would need to also build a new substation for Scenario C2, depending on a variation of factors and N-1 contingency ability.

Table 37. Problem Statement C - RFI Responses

	Project A – ESS	**Project E - Natural Gas Generator**	**Traditional (Line Only)**	**Traditional (Substation)**
Installation				
Procurement, Design and Installation	6 - 8 months	10 - 11 months	3 - 12 months	12 - 36 months
Operations and Maintenance				
Maintenance Requirements	Annual or quarterly visual inspections	Every 2,000 operating hours	3 - 5 years visual inspection	Monthly visual inspection
Duration of Maintenance Outages	8 - 24 hours annually	1 - 3 days	N/A	N/A
Environmental Issues	None. Recycling program exist.	None	None	None
Performance				
Expected Up-time	95% - 98%	94%	99.9%	99.9%
Expected Useful Life	15 - 20 years	20 years	40 - 60 years	40 - 60 years
Costs				
Budgetary Cost for Utility Ownership	$300 - $500 per kWhr	$2,500 - $3,500 per kW	$150,000 - $500,00 per mile	$1.5M - $2M
Estimated Annual Operating Costs	$10 - $50 per kW	$0.03 per kWhr	$1,000 per mile	$2,000

As stated in the previous problem statements, for the comparison analysis of this scenario, Dakota Electric is assuming land is available and affordable for the proposed NWS and the traditional substation. It was also assumed the NWS permitting would be comparable to the permitting cost and time duration as the traditional solution. Decommissioning costs are not included for any of the solutions listed in the table. The RFI responses lacked in sufficient detail to include decommissioning costs in this analysis.

In Table 38 the costs are assumed for a Scenario C1. The following assumptions have been made:

- 500 kW of NWS capacity is required to handle the initial demand, (2 hours or 1,000 kWhr).
- The cost to replace the batteries at 15 years is assumed at 60% of the initial costs.
- ESS energy loss is assumed to be 5-10% of the rating of the ESS unit under normal operation. For this analysis 5% of the kWhr rating was used. The cost of the energy for the calculation of losses is $0.07 per kWhr.
- A three mile, three-phase distribution line was installed for the traditional solution.
- Existing DSM would be utilized in lieu of building a new substation for N-1 contingency purposes.
- Traditional distribution line on Dakota Electric system has a 2.5% line loss.

Table 38. Estimated Cost for Problem Statement C - Scenario C1

	Project A – ESS	**Project E - Natural Gas Generator**	**Traditional (Line Only)**
Initial Costs (unit)	$300 - $500 per kWhr	$2,500 - $4,500 per kW	$150,000 - $200,000 per mile
Initial Cost	$0.9M - $1.5M	$1.3M - $2.3M	$450,000 - $600,000
Rejuvenation Costs at 15 years	$0.54M - $0.9M	Limited	-0-
Annual Energy Loss	$250,000	Limited	$100
Annual O&M Costs	$10 - $50 per kW	$0.03 per kWhr	$1,000 per mile
25-year Total Costs	>$3.0 million	>$1.5 million	>$0.6 million

In Table 39 the costs are assumed for a Scenario C2. The following assumptions have been made:

- 2 MW of NWS capacity is required to handle the initial demand (2 hours at 4,000 kWhr).
- The cost to replace the batteries at 15 years is assumed at 60% of the initial costs.
- ESS energy loss is assumed to be 5-10% of the rating of the ESS unit under normal operation. For this analysis 5% of the kWhr rating was used. The cost of the energy for the calculation of losses is $0.07 per kWhr.
- A three mile, three-phase distribution line was installed for the traditional solution.
- Traditional distribution line on Dakota Electric system has a 2.5% line loss.
- The new substation is located next to an existing transmission line with sufficient capacity available.

Table 39. Estimated Costs for Problem Statement C - Scenario C2

	Project A – ESS	Project E - Natural Gas Generator	Traditional (Line Only)	Traditional (Substation & Line)
Initial Costs (unit)	$300 - $500 per kWhr	$2,500 - $4,500 per kW	$150,000 - $200,000 per mile	$150,000 - $200,000 per mile; $2M substation
Initial Cost	$4.8M - $8.0M	$5M - $9M	$450,000 - $600,000	$2.5M
Rejuvenation Costs at 15 years	$2.9M - $4.8M	Limited	-0-	-0-
Annual Energy Loss	$250,000	Limited	$200	$200
Annual O&M Costs	$10 - $50 per kW	$0.03 per kWhr	$1,000 per mile	$1,000 per mile
25-year Total Costs	>$12.7 million	>$5.3 million	>$0.6 million	>$2.6 million

Dakota Electric posed this problem statement thinking this would be a good scenario when NWS would be most cost effective. Dakota Electric often faces the decision of traditionally building in a specific area to address a small step change in capacity needs. In the traditional solution, the infrastructure built in response to the step change will be multiple times larger than the immediate capacity need required. This is to account for future growth in the area. There is a cost savings if Dakota Electric is able to delay the traditional solution of building infrastructure for a short period of time, (1 – 4 years) using an NWS. Once growth in the area results in a significant step change, the traditional building of infrastructure would need to occur and the NWS would no longer be needed. Being able to use the NWS in another location on the distribution system would continue to provide a cost benefit to Dakota Electric and its members. This is a niche that has not yet been discovered by the NWS market.

14. Problem Statement D – Mobile Solution

Problem Statement D – Mobile Solution

During times of emergency or planned maintenance, specific portions of the distribution system need to be supported due to maintenance outages or storm damage. The assumption is 500 kW of generation would be adequate to provide the necessary support for the affected area. NWS(s) would need to be a trailer mounted generation source which could be driven to a site.

Scenario D1 – Assume the 500 kW of generation support is required for 24 hours a day for several consecutive days. The mobile NWS will be interconnected to the distribution system to support the area.

Scenario D2 – Assume the 500 kW of generation support is required for 24 hours a day for several consecutive days. The mobile NWS will be interconnected to an electrical island, (i.e., microgrid), and will be the sole electrical supply for the load.

Problem Statement D described another resiliency distribution system problem where Dakota Electric would normally evaluate having a fossil fuel reciprocating engine mounted on a flatbed trailer. Dakota Electric only received one response for this problem statement with the proposed NWS being an ISO shipping container of batteries on a flatbed trailer. Additional equipment required with the mobile solution are an inverter(s) and pad-mount transformer along with the necessarily cabling to interconnect to the distribution grid.

The Respondent did state this NWS was a concept solution and has not been installed by the Respondent. It was estimated that the lead time for such NWS would be approximately six months. Similar maintenance requirements and performance expectations were listed for this mobile NWS as listed in previous problem statements that included batteries as the NWS.

For this problem statement the proposed NWS did not differentiate between Scenario D1 and D2. As the NWS proposed was a concept solution, many specific details were not provided. Prior to Dakota Electric considering this NWS, further investigation on items such as charging and discharging durations and cycles of the proposed batteries would be necessary.

15. Vision for Planning, Development and Use of the Distribution System

Section D.2. In addition to the 5-year Action Plan, Dakota Electric shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Dakota Electric is currently using.

For the next 10-20 years, Dakota Electric is envisioning a continued increase in the number of member-owned DER systems integrating with the distribution system. The quantity of systems to be interconnected is unknown and there is quite a difference of opinion of how many systems will be interconnected. If the number of systems interconnected continues at the existing pace, then few issues are expected. If the amount of DER systems increases but at a reasonable level, Dakota Electric's distribution system will be able to handle up to 20-30% of the peak load on each of the feeders. If the number of systems interconnected is above the 20-30% penetration level, then additional capital costs to mitigate the effects of the member-owned generation is expected.

One of the areas which is starting to develop and will impact the adoption of DER, is with the interaction between the distribution system and the transmission system. The rules and requirements for operating and approving DER generation applications that result in exceeding the minimum load of a substation and resulting in the back feeding of the transmission system are not fully defined. As the amounts of DER that is interconnected to the distribution substations increases and those substations start to back feed the transmission system it is also not clear what the operational requirements will be. There are many issues, including contractual and operational issues which need to be discussed and resolved to allow the incorporation of high levels of DER integration with the distribution system.

As a general rule of thumb, if the DER systems are sized similar to the existing loads, the process of integrating large amounts of DER is expected to be fairly direct and without significant capital costs. If DER systems are interconnected which are not sized to the load and thus place the excess energy on to the distribution grid, then capital costs to improve the distribution system are expected.

A few of the potential issues with increased levels of DER integration are as follows:

- DER is installed in clusters and is not evenly spread throughout the service territory.
- Distribution DER that is supplying transmission services, especially if that DER is aggregated with other distribution DER.

- The DER which is not sized to the load and is using the distribution system to carry larger amounts of energy than the native load required.

Use of Non-Wires Alternatives

One of the significant issues affecting the use of non-wires alternatives by Dakota Electric is the ability for the non-wires solution to provide the same or even similar reliability as the traditional wires solutions. If the NWS is used as a direct replacement for installing wires and not used in combination with the traditional wires solution, then it is making the members' electrical supply dependent upon the NWS. The following are some of the concerns with relying on NWS for supplying the members.

- If the NWS fails to provide reliable electric service, Dakota Electric will be responsible for any decision to use NWS over traditional solutions.
- If the NWS is hit by a storm, including tornadoes hitting a solar farm, or lighting damaging an energy storage system, there is not spare equipment sitting on a shelf in Minnesota that Dakota Electric can immediately obtain to repair and restore power to the members. It could take months to replace and repair an NWS that was damaged by a major storm. How would the electricity be supplied to the members during this time period?
- The NWS providers do not provide 24-hour response. They are not staffed to provide 24hr, 7 days a week, 365 days per year emergency response. Dakota Electric has not found an NWS provider that will contract around the clock repair response or contract to be liable for not responding. This may be a service that NWS providers may provide in the future, but it will come at some additional cost.
- Some of the suppliers of NWS have gone out of business. Electric utilities are not like that, even if the utility goes bankrupt the operation of the electrical delivery continues. Will the NWS vendor be there to honor any reliability contracts that they committed to?

Dakota Electric is presently using non-wires solutions to work in concert with the existing wires, through reducing the electrical demand by using load management or generating electricity using solar. Even with both solutions, if the amount of load or generation is great enough, risk management and accounting for the modes of failure must be understood and managed. If the amount of load being managed is great enough that the existing distribution system cannot supply the peak load upon the failure of the load management system, then redundancy for the load management system(s) and plans to operate during a failure must be developed. Also, if there is a large amount of member-owned solar interconnected to a portion of the distribution system, the utility needs to know how much electrical demand would be applied to the distribution feeder immediately after an extended electrical outage, when the solar is not available.

While these are just two examples of known issues of using NWS and integrating more DER, they are illustrative of the increasing complexity created using these new technologies. Dakota Electric is excited to be working on improving the distribution system through the installation of the AGi project. Dakota Electric is focused on completing the AGi project as the AGi project is envisioned to provide a foundation for future functionality to support the adoption of DER integration. Dakota Electric will continue to explore and evaluate non-wired solutions and the potential for their application on the Dakota Electric system.

16. Conclusions from NWS RFI Responses

Many of the vendors requested to provide responses to Dakota Electric's RFI mention that the capacity needs in each of the problem statements needed to be larger for the NWS to competitively compete with the utility's traditional solutions. Cost per kW drops as the project size increases, specifically for PV and battery systems. Costs also dropped when utility scale PV and battery system were installed in lieu of BTM installations. Most interesting was the concept of modular expansions of the battery and PV systems proposed. The modular concept would be beneficial if the capacity needs increased over the duration of the NWS expected useful life.

Still concerning is the expected up-time and expected useful life of the NWS. Many of the NWS expected up-time was, at best, 99%. This would mean the NWS would not be available for 3.65 days annually. Ideally down-time could be coordinated with reduced loading, however the RFI failed to ask if the expected down-time was schedulable.

The distribution infrastructure built by Dakota Electric is designed to have an expected useful life of 40 – 60 years. The NWS's expected useful life was between 15 - 25 years, before the degradation of capacity capability was significant.

One concept Dakota Electric's RFI lacked, was a discussion on what happens at the end of life of the NWS. Is the NWS rebuilt? Is the NWS replaced with a traditional solution? These will be concerns Dakota Electric would need to address before choosing an NWS in lieu of a traditional solution. Other considerations in this analysis would need to include whether land or easements are available for the traditional solution at the end of life of a NWS. Land constraints are an issue if the traditional distribution infrastructure is not expanded in conjunction with load growth in a specific area.

17. NWS Lesson Learned

The main lesson Dakota Electric learned from the RFI exercise was that NWS are not a global solution to every distribution system problem. However, there are specific scenarios in which NWS should be considered in lieu of traditional building of distribution circuits. The specific scenarios for NWS are <u>not necessarily tied to a cost level of an infrastructure project</u>. Often the scenarios in which NWS would be considered are related to step change needs in available capacity for an area that is underserved for short durations. Also, for most NWS to be effective the underserved period of time needs to occur infrequently. ESS solutions have promise for use in these type of scenarios as does PV systems for summer peaking situations. Today, the price point of ESS is still significantly higher than PV systems but the attractiveness of ESS's utility-controlled discharging is significant. Demand-side management still is the lowest cost NWS available in the market today. It was surprising that DSM was not mentioned as a solution for all problem statements by the RFI respondents. DSM is the tool Dakota Electric has used for over 30 years, continues to regularly use and has been very successful in promoting this option to the membership.

IDP Report Summary and Suggestions for Future IDP Reports

Dakota Electric created the 2019 IDP report to be informative as well as educational. Dakota Electric staff along with employees of STAR Energy worked throughout 2019 to gather and report on the information contained in this report. Employees from the Center for Energy and Environment also provided input and guidance during the development of the IDP report. Dakota Electric is especially grateful for both of these organizations for their assistance throughout the project. The gathering of data, completing the analysis requested and the development of the IDP report involved a significant effort for all involved.

For future IDP reports Dakota Electric would like to encourage a process and review of the information requests so that the data included in future IDPs is efficiently gathered and presented. It may be that adjustment of the requests or better understanding of what is being requested could reduce the effort required by Dakota Electric and may lead to a better response. It would also be helpful to document how the information being requested will be utilized, so that adjustments to the data provided can help support the use cases for the data. One possible method to complete this review and discussion, would be to create a working group of stakeholders, including representatives from each of the regulated utilities, to review and discuss a draft of the Commission's IDP order for the next round of IDP reports.

The portions of the IDP report which required the greatest effort included:

- <u>Section A: Questions #15 and #16</u> – Request to provide costs by category for DER integration. Question #16 was not difficult to provide for the 2019 IDP report as there were limited charges to members for DER integration. The manual process of looking at each of the DER applications and identifying which category would a charge fall into was not that time consuming, for the minor amount of interconnections Dakota Electric had for 2018. The assumption is the categories listed will remain consistent for future IDP reports.

  On the other hand, Question #15, listing the costs which Dakota Electric incurred for DER integration by category, was quite impossible. Dakota Electric has not kept separate accounting records of all Dakota Electric labor for DER integration efforts or any other of the listed categories. Dakota Electric is instituting new accounting practices for engineering employees to report their work by all of these unique DER integration categories for future IDP reporting. Dakota Electric is also looking at ways to account for field crew labor associated with the testing and metering of DER installations which is much more complicated. Meter installation is already accounted for under Dakota Electric's normal metering account record and is not accounted for by use of the meter.

In addition, the make-ready construction is accounted for under Dakota Electric's normal construction categories. Creating a custom accounting process for these actions, just for getting this data for the IDP reporting, is costly.

- Section A: Question 29 – Requesting a listing of the planned distribution projects for the next 5 years. This was a very hard question to answer for Dakota Electric. Dakota Electric first needed to determine what was what is considered a "distribution project". Dakota Electric decided to report any project with an expected cost of over $50,000, as below this amount would start getting into more general projects, such as transformer replacements and interconnections of new commercial services. Dakota Electric believes these general projects was not what the Commission had in mind with this question.

  Dakota Electric next needed to determine what is considered a "planned" project. At Dakota Electric projects can occur in multiple ways. There are projects that are identified internally, reviewed for necessity and included in the annual capital budget for construction. There also are construction projects that occur in response to request by members, cities and counties. These projects are known to Dakota Electric however, often these projects have a short notification window and are not specifically listed in Dakota Electric's annual capital budget for construction. As Dakota Electric is unable to plan and commit to specific construction projects further than a few months ahead of actual construction, providing an accurate list of 5-year planned projects is not possible.

- Section B – Preliminary Hosting Capacity Data. As discussed within Section B, the definition of what is minimum load has not been defined. As discussed within Section B, there are many activities on the distribution system, including transferring loads to other feeders as the result of routine maintenance, which affect the loading on a feeder. The tools available to gather the real-time feeder and substation loading are reporting the actual load level which includes zero kW during outages or during maintenance activities. For future IDP reports, it would be helpful to better understand the nature of how the real-time operation of the distribution system affects minimum load gathering and to incorporate within the data request a realization of the difficulties in gathering this data. It would also be beneficial to have a discussion about how the data is to be used. This may lead to more efficient ways to provide the data so it is useful for the intended purpose.

  The effort required to gather and cleanse the individual feeder minimum load data was significant. Dakota Electric requests for future IDPs that substation minimum load data be reported instead of the individual feeder minimum load levels. Dakota Electric found the limiting level for DER integration to be the point when the substation back feeds the transmission system. With that in mind, knowing the substation minimum load would be more useful than knowing the individual feeder minimum loads. It is important to keep in mind the sum of the feeder minimum loads does not equal the substation minimum loading as each of the feeder reach minimum loading at different times.

Appendix A – DER Summary Report

Dakota Electric Association - DER Summary Report August 2019

Substation				Load Control Receiver Loads												Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Apple Valley	**21FB01**	**695**	471	430	1376.2	20	71.3	9	24.7	0	0.0	6	15.1	14	61.6	2	2715.0	0	0.0	2	7.7	1	20.0
	21FB02	**1,577**	988	861	2666.3	63	193.1	48	250.9	0	0.0	10	34.2	116	522.0	2	884.0	0	0.0	3	15.8	0	0.0
	21FB03	**609**	378	337	1018.7	25	97.9	10	51.6	0	0.0	6	18.0	16	72.0	0	0.0	0	0.0	2	22.8	0	0.0
	21FB04	**712**	440	389	1187.4	23	88.4	14	88.8	0	0.0	2	6.5	18	81.0	2	1440.0	1	80.0	1	5.0	0	0.0
	21FB05	**199**	121	102	331.4	8	30.1	9	60.3	0	0.0	1	1.0	5	22.5	1	936.0	0	0.0	0	0.0	0	0.0
	21FB06	**1,789**	907	820	2272.1	33	113.5	28	153.2	0	0.0	7	42.0	50	225.0	0	0.0	0	0.0	0	0.0	0	0.0
Total	**6**	**5,581**	**3305**	**2939**	**8852.1**	**172**	**594.3**	**118**	**629.5**	**0**	**0.0**	**32**	**116.8**	**219**	**984.1**	**7**	**5975.0**	**1**	**80.0**	**8**	**51.3**	**1**	**20.0**
Burnscott	**31FB01**	**787**	403	381	966.9	9	29.9	13	69.9	0	0.0	4	13.7	8	34.5	0	0.0	0	0.0	0	0.0	0	0.0
	31FB02	**35**	24	24	166.8	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	3	2541.0	1	1048.0	0	0.0	0	0.0
	31FB03	**529**	340	334	861.4	8	23.5	5	10.9	0	0.0	0	0.0	6	27.0	1	569.0	1	878.0	0	0.0	0	0.0
Total	**3**	**1,351**	**767**	**739**	**1995.1**	**17**	**53.4**	**18**	**80.8**	**0**	**0.0**	**4**	**13.7**	**14**	**61.5**	**4**	**3110.0**	**2**	**1926.0**	**0**	**0.0**	**0**	**0.0**
Burnsville - N	**05FB01**	**1,752**	852	746	2408.1	53	199.0	32	159.2	0	0.0	14	54.2	49	220.5	1	216.0	0	0.0	1	2.7	0	0.0
	05FB03	**1,112**	627	591	1947.0	21	81.9	19	113.2	0	0.0	8	33.0	44	193.5	0	0.0	0	0.0	4	29.0	0	0.0
	05FB05	**1,221**	586	545	1651.2	13	35.5	33	146.0	0	0.0	9	30.0	17	76.5	0	0.0	0	0.0	3	20.3	0	0.0
	05FB07	**165**	74	65	202.7	1	7.2	6	43.1	0	0.0	2	10.0	3	13.5	3	372.0	0	0.0	0	0.0	0	0.0
	05FB09	**1,280**	758	697	2218.7	23	76.6	33	167.1	0	0.0	15	54.7	32	144.5	1	167.0	0	0.0	2	15.0	0	0.0
	05FB11	**1,420**	995	919	2683.2	32	97.6	26	126.9	0	0.0	15	47.4	17	71.5	0	0.0	0	0.0	0	0.0	0	0.0
Total	**6**	**6,950**	**3892**	**3563**	**11110.9**	**143**	**497.8**	**149**	**755.5**	**0**	**0.0**	**63**	**229.3**	**162**	**720.0**	**5**	**755.0**	**0**	**0.0**	**10**	**67.0**	**0**	**0.0**
Burnsville - S	**05FB02**	**1,523**	911	843	2395.8	16	53.2	24	122.3	1	29.8	5	24.5	45	201.0	3	1728.0	0	0.0	0	0.0	0	0.0
	05FB04	**2,132**	977	940	2503.0	13	47.3	23	90.9	0	0.0	2	6.0	3	12.5	1	559.0	0	0.0	0	0.0	0	0.0
	05FB06	**1,045**	256	245	804.6	3	10.3	12	110.2	0	0.0	1	1.0	7	31.5	5	1614.0	1	737.0	2	5.0	0	0.0
	05FB08	**900**	564	538	1530.7	9	29.1	16	60.0	0	0.0	3	11.0	61	274.5	2	407.0	1	737.0	1	5.0	0	0.0
	05FB10	**456**	272	243	756.0	13	50.1	10	38.8	0	0.0	8	20.2	19	87.5	0	0.0	0	0.0	0	0.0	0	0.0
Total	**5**	**6,056**	**2980**	**2809**	**7990.1**	**54**	**190.0**	**85**	**422.2**	**1**	**29.8**	**19**	**62.7**	**135**	**607.0**	**11**	**4308.0**	**2**	**1474.0**	**3**	**10.0**	**0**	**0.0**
Byllesby	**02FB01**	**67**	41	13	36.9	6	18.5	10	113.4	12	877.0	2	25.0	23	102.8	0	0.0	0	0.0	0	0.0	0	0.0
	02FB02	**70**	54	14	38.8	24	84.3	18	234.5	6	348.6	3	47.5	32	154.0	0	0.0	0	0.0	0	0.0	0	0.0
	02FB03	**76**	46	33	107.8	3	12.1	7	108.0	1	47.0	0	0.0	14	63.0	0	0.0	1	426.0	0	0.0	0	0.0
Total	**3**	**213**	**141**	**60**	**183.5**	**33**	**114.9**	**35**	**455.9**	**19**	**1272.6**	**5**	**72.5**	**69**	**319.8**	**0**	**0.0**	**1**	**426.0**	**0**	**0.0**	**0**	**0.0**

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Substation				Load Control Receiver Loads														Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Castle Rock	04FB01	112	75	38	110.4	11	42.6	16	177.6	3	130.4	0	0.0	30	134.3	0	0.0	1	115.0	0	0.0	0	0.0
	04FB02	245	141	56	158.5	31	111.0	40	427.0	23	1013.3	6	33.4	60	273.0	0	0.0	0	0.0	4	42.0	0	0.0
	04FB04	453	253	119	382.1	57	250.5	89	841.5	5	222.2	15	91.8	138	622.5	2	184.0	0	0.0	4	65.2	1	20.0
Total	**3**	**810**	**469**	**213**	**651.0**	**99**	**404.1**	**145**	**1446.1**	**31**	**1365.9**	**21**	**125.2**	**228**	**1029.8**	**2**	**184.0**	**1**	**115.0**	**8**	**107.2**	**1**	**20.0**
Colonial Hills - N	13FB01	733	387	367	1078.1	12	38.8	3	9.0	0	0.0	3	12.6	6	27.0	2	552.0	0	0.0	1	6.0	0	0.0
	13FB03	12	2	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	3384.0	0	0.0	0	0.0	0	0.0
	13FB04	559	344	310	1019.1	16	55.0	5	17.3	0	0.0	5	32.1	42	189.0	1	256.0	0	0.0	0	0.0	0	0.0
	13FB08	571	24	21	60.3	1	3.1	1	18.0	0	0.0	0	0.0	1	4.5	3	835.0	0	0.0	0	0.0	0	0.0
	13FB09	732	400	372	1065.3	10	32.1	10	50.8	0	0.0	1	5.0	65	291.0	2	1110.0	0	0.0	0	0.0	0	0.0
Total	**5**	**2,607**	**1157**	**1070**	**3222.8**	**39**	**129.0**	**19**	**95.1**	**0**	**0.0**	**9**	**49.7**	**114**	**511.5**	**9**	**6137.0**	**0**	**0.0**	**1**	**6.0**	**0**	**0.0**
Colonial Hills - S	13FB02	165	34	37	182.5	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	835.0	0	0.0	0	0.0	0	0.0
	13FB05	730	91	86	211.3	0	0.0	5	42.8	0	0.0	0	0.0	66	297.0	0	0.0	0	0.0	0	0.0	0	0.0
	13FB06	399	259	243	749.0	6	20.3	8	37.1	0	0.0	3	7.5	7	31.5	0	0.0	0	0.0	0	0.0	0	0.0
	13FB07	69	24	26	208.0	0	0.0	0	0.0	0	0.0	0	0.0	3	13.5	2	730.0	0	0.0	0	0.0	0	0.0
	13FB10	96	5	5	23.5	0	0.0	1	21.7	0	0.0	0	0.0	0	0.0	2	843.0	0	0.0	0	0.0	0	0.0
Total	**5**	**1,459**	**413**	**397**	**1374.3**	**6**	**20.3**	**14**	**101.6**	**0**	**0.0**	**3**	**7.5**	**76**	**342.0**	**5**	**2408.0**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**
Dakota Heights	17FB01	990	652	581	1760.5	34	109.3	37	289.9	0	0.0	10	35.3	25	112.5	0	0.0	0	0.0	1	4.8	0	0.0
	17FB02	762	460	401	1291.3	18	56.1	21	167.2	0	0.0	13	36.7	79	355.5	0	0.0	0	0.0	2	13.6	0	0.0
	17FB03	632	418	368	1165.5	18	64.7	26	224.4	0	0.0	4	11.5	45	202.8	0	0.0	0	0.0	0	0.0	0	0.0
	17FB04	443	225	192	641.0	8	27.7	23	145.8	0	0.0	8	50.9	37	166.5	4	1558.0	0	0.0	0	0.0	0	0.0
	17FB05	824	523	475	1431.2	20	62.1	25	177.9	0	0.0	4	17.0	30	136.3	0	0.0	0	0.0	0	0.0	0	0.0
	17FB06	579	427	403	1139.3	15	52.7	7	35.1	0	0.0	3	9.1	24	108.0	1	625.0	0	0.0	0	0.0	0	0.0
Total	**6**	**4,230**	**2705**	**2420**	**7428.8**	**113**	**372.6**	**139**	**1040.3**	**0**	**0.0**	**42**	**160.5**	**240**	**1081.6**	**5**	**2183.0**	**0**	**0.0**	**3**	**18.4**	**0**	**0.0**

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Substation				Load Control Receiver Loads												Demand Management Systems									
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Deerwood	12FB01	690	463	415	1326.7	25	111.0	19	85.1	0	0.0	8	45.5	43	193.5	2	3288.0	0	0.0	2	30.8	0	0.0
	12FB02	976	640	567	1744.0	28	96.2	47	441.2	0	0.0	3	8.9	171	767.5	2	1135.0	0	0.0	1	15.2	0	0.0
	12FB03	1,209	662	639	1736.9	8	24.3	16	75.5	0	0.0	6	18.8	4	15.0	2	672.0	0	0.0	0	0.0	0	0.0
	12FB04	2,493	893	851	2349.8	24	78.4	18	103.9	0	0.0	3	30.4	16	72.0	0	0.0	0	0.0	0	0.0	0	0.0
	12FB05	1,808	1311	1233	3401.8	25	82.7	17	93.7	0	0.0	4	22.8	244	1100.0	1	415.0	0	0.0	2	12.0	0	0.0
Total	**5**	**7,176**	**3969**	**3705**	**10559.2**	**110**	**392.6**	**117**	**799.4**	**0**	**0.0**	**24**	**126.4**	**478**	**2148.0**	**7**	**5510.0**	**0**	**0.0**	**5**	**58.0**	**0**	**0.0**
Dodd Park	22FB01	1,550	924	860	2443.9	39	114.1	24	118.8	0	0.0	10	22.6	36	162.0	0	0.0	0	0.0	1	10.0	0	0.0
	22FB02	961	549	519	1414.5	17	50.4	13	61.7	0	0.0	1	5.0	26	116.3	1	94.0	0	0.0	0	0.0	0	0.0
	22FB03	1,044	537	491	1436.2	12	36.9	14	81.1	0	0.0	5	12.6	72	324.0	0	0.0	0	0.0	0	0.0	0	0.0
	22FB04	1,247	488	447	1449.0	6	23.6	21	144.4	0	0.0	4	29.8	256	1151.3	0	0.0	0	0.0	0	0.0	0	0.0
	22FB05	899	645	550	1704.7	60	213.6	29	135.8	0	0.0	7	14.3	186	837.0	0	0.0	0	0.0	2	13.1	0	0.0
	22FB06	1,660	937	849	2441.0	23	80.4	32	246.6	0	0.0	6	23.6	130	585.0	3	860.0	1	547.0	1	6.0	0	0.0
Total	**6**	**7,361**	**4080**	**3716**	**10889.3**	**157**	**519.0**	**133**	**788.4**	**0**	**0.0**	**33**	**107.9**	**706**	**3175.6**	**4**	**954.0**	**1**	**547.0**	**4**	**29.1**	**0**	**0.0**
Eagan	06FB01	471	300	261	850.6	25	90.6	12	76.6	0	0.0	0	0.0	10	45.0	1	806.0	0	0.0	1	1.8	0	0.0
	06FB02	309	206	189	549.9	5	17.6	7	44.4	0	0.0	1	6.4	3	14.5	0	0.0	0	0.0	0	0.0	0	0.0
	06FB03	352	160	145	460.2	5	15.4	4	25.2	0	0.0	2	8.0	24	108.0	0	0.0	0	0.0	0	0.0	0	0.0
	06FB04	613	366	333	1037.0	19	66.0	5	16.5	0	0.0	3	10.6	9	40.5	0	0.0	0	0.0	1	7.6	0	0.0
	06FB05	494	318	280	903.6	26	87.0	10	46.5	0	0.0	3	10.5	10	45.0	0	0.0	0	0.0	1	4.5	0	0.0
	06FB06	149	96	89	258.9	5	16.8	9	82.5	0	0.0	0	0.0	4	18.0	1	461.0	0	0.0	1	1.7	0	0.0
Total	**6**	**2,388**	**1446**	**1297**	**4060.2**	**85**	**293.4**	**47**	**291.7**	**0**	**0.0**	**9**	**35.5**	**60**	**271.0**	**2**	**1267.0**	**0**	**0.0**	**4**	**15.6**	**0**	**0.0**
Empire	23FB01	248	123	62	177.6	19	58.0	29	244.9	19	1065.8	3	8.3	42	189.0	0	0.0	0	0.0	0	0.0	0	0.0
	23FB02	210	140	52	157.9	37	119.3	42	467.6	26	1683.4	7	78.7	68	304.5	0	0.0	0	0.0	0	0.0	0	0.0
	23FB04	120	85	31	95.5	20	80.8	30	454.6	3	133.0	4	8.8	39	175.8	1	97.0	0	0.0	1	15.2	0	0.0
Total	**3**	**578**	**348**	**145**	**431.0**	**76**	**258.1**	**101**	**1167.1**	**48**	**2882.2**	**14**	**95.8**	**149**	**669.3**	**1**	**97.0**	**0**	**0.0**	**1**	**15.2**	**0**	**0.0**

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Substation				Load Control Receiver Loads												Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Fischer - W	11FB01	246	123	108	333.7	2	8.7	0	0.0	0	0.0	3	8.0	5	22.5	3	710.0	0	0.0	0	0.0	0	0.0
	11FB02	809	302	280	729.6	6	15.8	26	187.0	0	0.0	1	5.0	2	9.0	6	2818.0	0	0.0	0	0.0	0	0.0
	11FB07	341	154	149	462.8	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	4	621.0	0	0.0	0	0.0	0	0.0
	11FB09	1,338	876	831	2262.7	26	75.5	27	107.4	0	0.0	2	6.0	11	49.5	0	0.0	0	0.0	0	0.0	0	0.0
	11FB10	371	183	167	440.9	1	3.4	5	17.1	0	0.0	0	0.0	2	9.0	0	0.0	1	1142.0	0	0.0	0	0.0
	11FB12	1,682	1064	988	2872.3	30	93.6	34	170.0	0	0.0	4	14.1	60	267.5	0	0.0	0	0.0	3	20.4	0	0.0
Total	**6**	**4,787**	**2702**	**2523**	**7102.0**	**65**	**197.0**	**92**	**481.5**	**0**	**0.0**	**10**	**33.1**	**80**	**357.5**	**13**	**4149.0**	**1**	**1142.0**	**3**	**20.4**	**0**	**0.0**
Fischer - E	11FB03	693	312	296	928.1	8	60.5	3	42.4	0	0.0	0	0.0	8	34.8	1	691.0	0	0.0	0	0.0	0	0.0
	11FB04	905	496	451	1301.9	17	49.6	19	104.6	0	0.0	4	15.3	8	36.0	2	1085.0	0	0.0	1	3.0	0	0.0
	11FB05	386	258	229	674.9	15	52.8	12	69.4	0	0.0	2	10.0	14	63.0	0	0.0	0	0.0	0	0.0	0	0.0
	11FB06	681	294	260	730.8	7	25.5	3	26.5	0	0.0	0	0.0	71	319.5	2	1344.0	0	0.0	0	0.0	0	0.0
	11FB08	1,098	706	657	1877.7	22	70.0	17	84.7	0	0.0	0	0.0	12	54.0	0	0.0	0	0.0	1	6.0	0	0.0
	11FB11	956	336	328	752.6	1	3.1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Total	**6**	**4,719**	**2402**	**2221**	**6266.0**	**70**	**261.5**	**54**	**327.6**	**0**	**0.0**	**6**	**25.3**	**113**	**507.3**	**5**	**3120.0**	**0**	**0.0**	**2**	**9.0**	**0**	**0.0**
Hastings	03FB01	1,595	797	719	1858.0	25	73.2	21	146.9	1	65.0	6	30.0	91	414.0	0	0.0	0	0.0	0	0.0	0	0.0
	03FB02	213	129	48	142.6	25	85.6	33	381.9	28	2139.6	4	51.1	42	194.5	0	0.0	0	0.0	0	0.0	0	0.0
	03FB03	233	148	57	161.7	30	111.3	23	330.4	33	2335.6	3	10.1	48	217.0	1	0.0	0	0.0	1	5.0	0	0.0
	03FB04	271	133	68	199.5	21	66.7	30	263.1	22	1414.5	2	16.8	21	94.5	0	0.0	0	0.0	1	3.0	1	20.0
Total	**4**	**2,312**	**1207**	**892**	**2361.8**	**101**	**336.8**	**107**	**1122.3**	**84**	**5954.7**	**15**	**108.0**	**202**	**920.0**	**1**	**0.0**	**0**	**0.0**	**2**	**8.0**	**1**	**20.0**
Kenrick	26FB01	205	120	115	289.9	4	10.7	3	40.0	0	0.0	1	2.0	2	9.0	0	0.0	0	0.0	0	0.0	0	0.0
	26FB02	362	143	130	390.8	2	4.1	1	7.5	0	0.0	1	4.0	13	58.5	0	0.0	1	384.0	0	0.0	0	0.0
	26FB03	84	29	20	147.4	5	21.9	9	73.4	0	0.0	1	27.0	9	40.5	1	800.0	0	0.0	0	0.0	0	0.0
	26FB04	670	375	275	926.1	62	276.1	83	892.4	1	5.0	37	290.3	124	558.0	2	52.0	0	0.0	0	0.0	0	0.0
Total	**4**	**1,321**	**667**	**540**	**1754.2**	**73**	**312.8**	**96**	**1013.3**	**1**	**5.0**	**40**	**323.3**	**148**	**666.0**	**3**	**852.0**	**1**	**384.0**	**0**	**0.0**	**0**	**0.0**
Lake Marion	15FB01	445	231	171	590.4	27	114.0	53	613.1	0	0.0	11	128.6	80	360.7	1	0.0	0	0.0	3	27.0	0	0.0
	15FB03	382	205	125	387.4	30	112.5	56	565.3	1	30.0	14	192.5	76	336.8	0	0.0	1	0.0	1	5.0	0	0.0
	15FB04	549	256	145	457.9	46	167.3	70	888.1	0	0.0	10	117.6	113	509.0	0	0.0	0	0.0	1	11.4	4	21.5
Total	**3**	**1,376**	**692**	**441**	**1435.7**	**103**	**393.8**	**179**	**2066.5**	**1**	**30.0**	**35**	**438.7**	**269**	**1206.5**	**1**	**0.0**	**1**	**0.0**	**5**	**43.4**	**4**	**21.5**

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Substation				Load Control Receiver Loads												Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Lakeville	**25FB01**	**2,042**	1133	1064	2633.2	23	63.2	25	163.8	0	0.0	3	19.2	18	81.0	0	0.0	1	383.0	0	0.0	0	0.0
	25FB02	**1,170**	594	537	1577.2	27	91.2	19	127.6	0	0.0	6	23.4	115	517.5	0	0.0	1	0.0	0	0.0	0	0.0
	25FB03	**942**	367	344	921.0	5	22.4	39	318.0	0	0.0	1	2.0	25	112.5	1	0.0	0	0.0	0	0.0	0	0.0
	25FB04	**1,495**	1083	1037	2548.0	18	55.6	6	38.5	0	0.0	5	18.3	232	1044.0	0	0.0	0	0.0	0	0.0	0	0.0
	25FB05	**1,376**	935	905	2033.4	4	12.1	9	54.2	0	0.0	2	11.7	325	1460.1	0	0.0	0	0.0	0	0.0	0	0.0
	25FB06	**1,061**	426	393	1075.7	3	9.1	8	80.7	0	0.0	0	0.0	15	67.5	1	778.0	0	0.0	1	5.0	0	0.0
Total	**6**	**8,086**	**4538**	**4280**	**10788.5**	**80**	**253.6**	**106**	**782.8**	**0**	**0.0**	**17**	**74.6**	**730**	**3282.6**	**2**	**778.0**	**2**	**383.0**	**1**	**5.0**	**0**	**0.0**
Lebanon Hills	**16FB01**	**615**	369	322	1011.2	26	91.4	22	163.0	0	0.0	4	19.4	30	135.0	0	0.0	0	0.0	3	22.4	0	0.0
	16FB02	**1,096**	663	528	1767.2	65	268.4	123	1147.3	0	0.0	24	217.2	183	822.1	0	0.0	1	200.0	2	13.6	1	38.0
	16FB03	**956**	448	370	1210.4	39	149.1	38	380.0	0	0.0	14	115.7	100	453.7	1	288.0	0	0.0	2	35.9	0	0.0
	16FB04	**749**	435	377	1210.5	33	113.4	17	81.4	0	0.0	10	80.2	32	144.0	1	675.0	0	0.0	2	10.0	0	0.0
	16FB05	**710**	496	447	1290.3	26	82.7	11	36.3	0	0.0	6	29.8	13	57.5	0	0.0	0	0.0	1	10.0	0	0.0
	16FB06	**566**	343	266	930.2	40	187.9	48	461.3	1	102.0	21	89.0	97	441.0	0	0.0	0	0.0	3	27.3	0	0.0
Total	**6**	**4,692**	**2754**	**2310**	**7419.8**	**229**	**892.9**	**259**	**2269.3**	**1**	**102.0**	**79**	**551.3**	**455**	**2053.3**	**2**	**963.0**	**1**	**200.0**	**13**	**119.2**	**1**	**38.0**
Lemay Lake	**14FB01**	**5**	0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	14FB02	**352**	13	10	45.6	0	0.0	0	0.0	0	0.0	0	0.0	1	4.5	2	690.0	0	0.0	0	0.0	0	0.0
	14FB03	**1,641**	545	466	1250.6	12	39.2	15	63.0	0	0.0	2	12.5	76	340.5	0	0.0	0	0.0	0	0.0	0	0.0
	14FB04	**1,134**	150	150	442.5	1	3.0	3	19.9	0	0.0	0	0.0	8	36.0	1	520.0	0	0.0	1	5.9	0	0.0
	14FB05	**693**	171	125	461.8	0	0.0	0	0.0	0	0.0	0	0.0	55	247.5	2	781.0	0	0.0	1	133.2	0	0.0
	14FB06	**713**	253	243	855.5	6	18.9	1	7.2	0	0.0	2	7.8	43	192.6	1	1100.0	0	0.0	0	0.0	0	0.0
Total	**6**	**4,538**	**1132**	**994**	**3056.0**	**19**	**61.1**	**19**	**90.1**	**0**	**0.0**	**4**	**20.3**	**183**	**821.1**	**6**	**3091.0**	**0**	**0.0**	**2**	**139.1**	**0**	**0.0**
Marshan	**18FB01**	**536**	285	182	515.9	52	173.4	47	507.0	15	1156.2	14	54.6	87	390.8	0	0.0	0	0.0	4	1047.6	1	12.0
	18FB02	**377**	205	151	441.3	22	82.4	32	308.4	3	312.0	8	97.8	48	217.3	0	0.0	0	0.0	0	0.0	0	0.0
	18FB03	**68**	38	13	40.5	9	39.3	6	78.0	9	663.0	5	43.8	14	63.0	0	0.0	0	0.0	1	12.9	0	0.0
	18FB04	**243**	119	66	195.9	17	57.7	23	183.1	20	1408.0	5	73.5	33	146.4	0	0.0	1	202.0	1	10.0	0	0.0
Total	**4**	**1,224**	**647**	**412**	**1193.6**	**100**	**352.8**	**108**	**1076.5**	**47**	**3539.2**	**32**	**269.7**	**182**	**817.5**	**0**	**0.0**	**1**	**202.0**	**6**	**1070.5**	**1**	**12.0**

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Substation				Load Control Receiver Loads												Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Miesville	07FB01	171	96	47	132.0	12	67.4	21	315.7	13	1024.0	7	21.2	27	116.3	0	0.0	0	0.0	1	7.5	0	0.0
	07FB02	314	160	92	263.9	18	57.6	26	251.0	5	442.3	9	58.3	48	217.8	0	0.0	0	0.0	2	15.2	0	0.0
	07FB03	203	75	30	107.4	19	70.5	28	300.2	1	111.0	3	14.0	43	193.5	0	0.0	0	0.0	2	25.2	1	20.0
	07FB04	190	121	38	127.3	34	140.6	50	820.3	18	1218.0	14	79.0	54	257.5	0	0.0	0	0.0	3	25.7	0	0.0
	07FB05	346	175	83	258.3	37	201.5	43	517.8	13	923.0	7	59.4	76	342.9	0	0.0	0	0.0	1	36.0	0	0.0
Total	5	1,224	627	290	888.9	120	537.6	168	2205.0	50	3718.3	40	231.9	248	1128.0	0	0.0	0	0.0	9	109.6	1	20.0
Nininger	29FB01	321	176	156	382.3	7	19.8	19	133.2	1	88.0	1	5.0	60	271.0	0	0.0	0	0.0	0	0.0	0	0.0
	29FB03	342	165	148	396.7	9	27.4	16	173.0	0	0.0	1	5.5	24	108.0	0	0.0	0	0.0	0	0.0	0	0.0
	29FB04	164	82	45	126.7	7	28.5	21	278.9	14	1107.3	1	40.0	35	164.5	0	0.0	0	0.0	0	0.0	1	39.0
Total	3	827	423	349	905.7	23	75.7	56	585.1	15	1195.3	3	50.5	119	543.5	0	0.0	0	0.0	0	0.0	1	39.0
Orchard Lake	08FB01	857	509	425	1336.7	37	151.7	49	515.4	0	0.0	16	125.9	88	396.1	0	0.0	0	0.0	2	11.0	0	0.0
	08FB02	1,372	633	551	1600.3	17	56.2	20	176.4	0	0.0	4	16.7	77	345.0	1	98.0	0	0.0	0	0.0	0	0.0
	08FB03	1,279	605	568	1690.9	21	76.6	26	162.5	0	0.0	5	19.0	30	134.0	1	49.0	0	0.0	0	0.0	0	0.0
	08FB04	1,040	552	499	1522.6	19	72.6	43	359.0	0	0.0	10	31.0	74	332.1	0	0.0	0	0.0	0	0.0	0	0.0
	08FB05	161	72	65	189.7	4	13.1	6	66.3	0	0.0	1	0.8	4	18.0	1	645.0	0	0.0	0	0.0	0	0.0
	08FB06	662	379	304	1030.7	31	122.5	60	565.2	0	0.0	15	153.0	113	512.3	0	0.0	0	0.0	1	1.9	0	0.0
Total	6	5,371	2750	2412	7370.9	129	492.7	204	1844.8	0	0.0	51	346.4	386	1737.5	3	792.0	0	0.0	3	12.9	0	0.0
Pilot Knob	19FB01	460	278	259	775.4	15	51.2	10	81.9	0	0.0	2	9.8	8	36.0	0	0.0	0	0.0	0	0.0	0	0.0
	19FB02	392	311	267	848.3	22	76.1	28	191.3	0	0.0	3	14.5	27	121.5	0	0.0	0	0.0	0	0.0	0	0.0
	19FB03	337	241	191	584.1	18	109.4	9	60.2	0	0.0	5	61.0	33	149.5	0	0.0	0	0.0	0	0.0	0	0.0
	19FB04	1,286	900	799	2495.8	52	190.8	104	895.6	0	0.0	11	126.5	149	668.5	0	0.0	0	0.0	2	12.8	0	0.0
	19FB05	750	581	541	1735.3	14	50.6	22	126.4	0	0.0	4	13.4	15	67.5	0	0.0	0	0.0	2	3.8	0	0.0
Total	5	3,225	2311	2057	6438.9	121	478.1	173	1355.4	0	0.0	25	225.2	232	1043.0	0	0.0	0	0.0	4	16.6	0	0.0
Randolph	32FB01	261	169	64	181.9	37	132.4	57	806.3	20	1070.7	8	72.3	80	357.5	0	0.0	0	0.0	2	31.4	0	0.0
	32FB02	128	72	27	111.7	19	67.5	28	363.7	15	757.8	2	22.0	44	195.0	3	928.0	0	0.0	2	12.8	1	10.0
	32FB03	13	6	1	2.5	1	2.5	2	43.0	1	47.0	0	0.0	2	10.0	0	0.0	1	276.0	0	0.0	0	0.0
	32FB04	128	80	29	81.9	14	46.4	18	256.1	16	969.6	2	8.5	35	155.5	0	0.0	0	0.0	2	19.0	0	0.0
Total	4	530	327	121	378.0	71	248.8	105	1469.1	52	2845.1	12	102.8	161	718.0	3	928.0	1	276.0	6	63.2	1	10.0

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Substation				Load Control Receiver Loads												Demand Management Systems							
	Feeder	Service	LCR	Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Ravenna	30FB01	30	12	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	4900.0	0	0.0	0	0.0	0	0.0
	30FB03	280	70	43	126.9	9	46.5	22	218.6	0	0.0	5	23.0	31	139.5	0	0.0	0	0.0	1	10.0	0	0.0
	30FB04	214	75	52	148.1	14	37.5	9	132.7	4	95.0	1	14.0	12	54.0	0	0.0	0	0.0	1	7.6	0	0.0
Total	**3**	**524**	**157**	**95**	**275.0**	**23**	**84.0**	**31**	**351.3**	**4**	**95.0**	**6**	**37.0**	**43**	**193.5**	**1**	**4900.0**	**0**	**0.0**	**2**	**17.6**	**0**	**0.0**
Ritter Park	27FB02	511	83	79	288.5	3	9.5	2	105.6	0	0.0	1	12.0	8	36.0	3	1380.0	0	0.0	2	45.1	0	0.0
	27FB03	413	228	214	756.8	13	50.5	31	235.3	0	0.0	8	22.5	41	183.4	1	965.0	0	0.0	1	7.2	0	0.0
	27FB04	1,351	734	647	2059.6	28	96.0	45	458.2	0	0.0	11	62.8	204	914.6	1	706.0	0	0.0	1	7.8	0	0.0
	27FB05	288	146	132	412.4	7	27.7	10	86.2	0	0.0	7	44.4	40	182.0	1	770.0	0	0.0	0	0.0	0	0.0
Total	**4**	**2,563**	**1191**	**1072**	**3517.3**	**51**	**183.7**	**88**	**885.3**	**0**	**0.0**	**27**	**141.7**	**293**	**1316.0**	**6**	**3821.0**	**0**	**0.0**	**4**	**60.2**	**0**	**0.0**
River Hills - W	09FB01	695	541	517	1173.9	8	23.4	5	21.9	0	0.0	2	5.2	25	112.5	1	338.0	0	0.0	0	0.0	0	0.0
	09FB05	1,603	668	640	1844.7	14	41.5	13	44.4	0	0.0	5	14.4	6	23.5	0	0.0	0	0.0	1	6.0	0	0.0
	09FB06	1,541	361	345	958.7	5	15.5	5	23.5	0	0.0	0	0.0	3	13.5	0	0.0	0	0.0	0	0.0	0	0.0
	09FB07	672	257	245	727.1	8	25.2	3	11.5	0	0.0	0	0.0	5	22.5	0	0.0	0	0.0	0	0.0	0	0.0
Total	**4**	**4,511**	**1827**	**1747**	**4704.4**	**35**	**105.6**	**26**	**101.3**	**0**	**0.0**	**7**	**19.6**	**39**	**172.0**	**1**	**338.0**	**0**	**0.0**	**1**	**6.0**	**0**	**0.0**
River Hills - E	09FB02	1,275	905	755	2097.1	26	84.5	15	88.4	0	0.0	4	13.9	119	530.5	0	0.0	0	0.0	0	0.0	0	0.0
	09FB03	636	442	406	1210.3	11	35.7	20	120.2	0	0.0	5	10.6	31	139.5	0	0.0	0	0.0	2	11.4	0	0.0
	09FB04	780	440	408	1302.0	22	92.1	15	180.4	0	0.0	6	27.0	24	105.0	0	0.0	0	0.0	0	0.0	0	0.0
	09FB08	179	39	44	144.7	0	0.0	0	0.0	0	0.0	0	0.0	1	4.5	0	0.0	0	0.0	0	0.0	0	0.0
	09FB10	512	530	352	888.9	4	13.2	7	34.9	0	0.0	1	18.7	173	778.0	0	0.0	0	0.0	0	0.0	0	0.0
Total	**5**	**3,382**	**2356**	**1965**	**5643.0**	**63**	**225.5**	**57**	**423.9**	**0**	**0.0**	**16**	**70.2**	**348**	**1557.5**	**0**	**0.0**	**0**	**0.0**	**2**	**11.4**	**0**	**0.0**
Vermillion River	24FB01	1,050	730	682	1932.6	22	68.0	31	262.8	0	0.0	5	18.4	63	282.0	1	92.0	1	264.0	2	17.9	0	0.0
	24FB02	243	151	80	240.3	12	46.4	36	388.3	10	517.0	3	42.0	43	196.3	1	350.0	0	0.0	2	41.9	0	0.0
	24FB03	243	121	67	194.0	24	102.0	20	378.9	2	80.3	2	19.0	51	225.0	0	0.0	0	0.0	0	0.0	0	0.0
	24FB04	127	50	19	66.6	6	32.5	14	190.0	9	429.0	0	0.0	18	77.7	1	180.0	0	0.0	0	0.0	0	0.0
	24FB05	24	11	6	18.7	1	2.8	3	33.0	0	0.0	0	0.0	4	18.0	0	0.0	1	893.0	0	0.0	0	0.0
	24FB06	1,470	965	896	2414.9	14	45.1	19	116.2	0	0.0	11	47.3	69	308.0	0	0.0	0	0.0	2	22.8	0	0.0
Total	**6**	**3,157**	**2028**	**1750**	**4867.1**	**79**	**296.8**	**123**	**1369.2**	**21**	**1026.3**	**21**	**126.7**	**248**	**1107.0**	**3**	**622.0**	**2**	**1157.0**	**6**	**82.7**	**0**	**0.0**

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Substation	Feeder	Service	LCR	Load Control Receiver Loads												Demand Management Systems							
				Air Cond		Heat Pump		Heat Device		Irrigation		Misc		Water Heat		Peak Alert Gens (Rate 70)		Curtailment (Rate 71)		Solar		Wind	
				Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW	Qty	kW
Wescott Park - E	20FB01	5	5	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	20FB03	5	4	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	20FB05	7	7	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	10500.0	0	0.0	0	0.0	0	0.0
Total	**3**	**17**	**16**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**1**	**10500.0**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**
Wescott Park - W	20FB02	6	0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	3	5800.0	0	0.0	0	0.0	0	0.0
	20FB04	523	320	267	912.8	31	142.3	44	419.1	0	0.0	20	103.1	67	306.3	0	0.0	0	0.0	1	6.0	0	0.0
	20FB06	506	308	265	960.0	23	84.2	24	181.1	0	0.0	2	5.1	26	117.0	0	0.0	0	0.0	0	0.0	0	0.0
	20FB07	4	0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	3050.0	0	0.0	0	0.0	0	0.0
Total	**4**	**1,039**	**628**	**532**	**1872.8**	**54**	**226.5**	**68**	**600.2**	**0**	**0.0**	**22**	**108.2**	**93**	**423.3**	**4**	**8850.0**	**0**	**0.0**	**1**	**6.0**	**0**	**0.0**
Yankee Doodle - N	10FB01	110	24	21	97.5	1	45.5	0	0.0	0	0.0	0	0.0	0	0.0	1	1116.0	0	0.0	0	0.0	0	0.0
	10FB03	805	474	428	1269.8	27	96.8	26	130.1	0	0.0	2	6.8	36	162.0	1	230.0	0	0.0	1	6.0	0	0.0
	10FB05	135	28	38	176.3	0	0.0	0	0.0	0	0.0	0	0.0	1	4.5	3	2509.0	0	0.0	1	30.0	0	0.0
	10FB07	426	156	147	435.2	3	10.8	3	23.0	0	0.0	1	208.0	6	26.4	1	575.0	0	0.0	0	0.0	0	0.0
Total	**4**	**1,476**	**682**	**634**	**1978.8**	**31**	**153.1**	**29**	**153.1**	**0**	**0.0**	**3**	**214.8**	**43**	**192.9**	**6**	**4430.0**	**0**	**0.0**	**2**	**36.0**	**0**	**0.0**
Yankee Doodle - S	10FB02	6	0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	3900.0	0	0.0	0	0.0	0	0.0
	10FB04	186	11	12	58.5	0	0.0	0	0.0	0	0.0	1	73.0	1	4.5	2	735.0	0	0.0	1	45.4	0	0.0
	10FB06	351	180	145	487.7	14	64.9	18	269.5	0	0.0	2	13.6	30	135.0	0	0.0	2	1037.0	3	27.0	0	0.0
	10FB08	2	0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	10FB10	14	5	5	17.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	366.0	0	0.0	0	0.0	0	0.0
Total	**5**	**559**	**196**	**162**	**563.2**	**14**	**64.9**	**18**	**269.5**	**0**	**0.0**	**3**	**86.6**	**31**	**139.5**	**4**	**5001.0**	**2**	**1037.0**	**4**	**72.3**	**0**	**0.0**
Grand Total	**168**	**108,220**	**57,932**	**50,872**	**149,530**	**2,758**	**10,075**	**3,286**	**28,917**	**375**	**24,061**	**752**	**4,809**	**7,296**	**32,825**	**127**	**86,023**	**20**	**9,349**	**125**	**2,287**	**12**	**201**

Appendix B – Substation and Feeder Minimum Loading Levels

Substation	Feeder	Peak Load	Minimum	Daytime Minimum
Byllesby (2)	Substation	3,502	230	299
	1		63	64
	2		29	71
	3		88	122
	4		28	68
Hastings (3)	Substation	9,961	1,706	2,173
	1		603	1,431
	2		91	136
	3		178	218
	4		131	225
Castle Rock (4)	Substation	3,029	577	743
	1		28	38
	2		70	75
	4		195	208
Burnsville North (5)	Substation	25,487	6,152	7,377
	1 (N)		1,063	1,226
	3 (N)		857	1,067
	5 (N)		649	770
	7 (N)		421	421
	9 (N)		837	1,085
	11 (N)		365	575
Burnsville South (5)	Substation	21,372	5,473	6,743
	2 (S)		1,498	1,883
	4 (S)		1,123	1,253
	6 (S)		1,534	2,033
	8 (S)		391	547
	10 (S)		276	346
Eagan (6)	Substation	9,051	2,138	2,833
	1		489	704
	2		141	144
	3		210	276
	4		353	406
	5		300	331
	6		162	235
Miesville (7)	Substation	6,643	1,034	1,510
	1		123	201
	2		136	136
	3		114	176
	4		105	140
	5		193	193
Orchard Lake (8)	Substation	19,119	3,922	5,104
	1		617	685
	2		189	189
	3		221	473
	4		190	247
	5		13	22

Substation	Feeder	Peak Load	Minimum	Daytime Minimum
River Hills East (9)	Substation	12,486	2,844	4,021
	2		852	1,183
	3		315	351
	4		202	1,433
	8		300	446
	10		266	369
River Hills West (9)	Substation	11,470	1,804	2,678
	1		582	749
	5		182	182
	6		731	1,069
	7		20	20
Yankee Doodle North (1	Substation	14,095	4,053	4,511
	1		1,006	1,591
	3		298	830
	5		491	1,033
	7		175	230
Yankee Doodle South (1	Substation	14,476	2,727	2,834
	2		3	3
	4		138	138
	6		505	505
	8		258	258
	10		94	126
Fischer West (11)	Substation	24,086	4,708	6,628
	1		285	548
	2		1,566	1,907
	7		650	851
	9		684	896
	10		161	214
Fischer East (11)	Substation	33,134	5,207	7,488
	3		1,291	1,630
	4		947	947
	5		258	284
	6		903	1,242
	8		660	701
Deerwood (12)	Substation	23,179	6,607	8,633
	1		808	992
	2		1,257	1,636
	3		922	1,247
	4		974	974
	5		1,365	1,845

Substation	Feeder	Peak Load	Minimum	Daytime Minimum
Colonial Hills North (13)	Substation	19,828	4,832	6,523
	1		574	574
	3		197	339
	4		656	775
	8		597	867
	9		1,128	1,417
Colonial Hills South (13)	Substation	13,332	3,340	4,534
	2		759	1,312
	5		692	692
	6		399	515
	7		356	460
	10		694	841
LeMay Lake (14)	Substation	23,030	8,878	10,360
	1		1,266	1,266
	2		219	219
	3		778	1,032
	4		1,580	2,180
	5		429	429
	6		80	89
Lake Marion (15)	Substation	5,330	1,356	1,356
	1		404	404
	3		228	315
	4		473	604
Lebanon Hills (16)	Substation	17,196	3,482	4,425
	1		489	621
	2		361	361
	3		519	876
	4		495	602
	5		281	385
	6		63	195
Dakota Heights (17)	Substation	22,548	3,664	4,155
	1		716	905
	2		599	735
	3		351	351
	4		194	196
	5		69	69
	6		456	610
Marshan (18)	Substation	5,862	314	314
	1		< 0	< 0
	2		83	222
	3		30	30
	4		158	158
Pilot Knob (19)	Substation	12,773	2,408	3,183
	1		257	356
	2		233	275
	3		218	268
	4		306	318
	5		697	894

Substation	Feeder	Peak Load	Minimum	Daytime Minimum
Wescott Park East (20)	Substation	7,563	0	0
	1		0	0
	3		0	0
	5		0	0
Wescott Park West (20)	Substation	10,808	867	867
	2		0	0
	4		325	325
	6		361	399
	7		0	0
	8		99	293
Apple Valley (21)	Substation	21,587	5,577	6,379
	1		877	1,002
	2		1,141	1,168
	3		368	411
	4		309	335
	5		240	302
	6		503	503
Dodd Park (22)	Substation	24,678	4,608	4,608
	1		1,040	1,061
	2		351	379
	3		367	367
	4		684	787
	5		111	111
	6		85	88
Empire (23)	Substation	3,938	512	600
	1		172	224
	2		136	158
	3		0	0
	4		102	120
Vermillion River (24)	Substation	11,296	1,868	2,809
	1		458	940
	2		146	239
	3		236	300
	4		190	246
	5		166	169
	6		843	976
Lakeville (25)	Substation	23,981	4,800	7,229
	1		1,139	1,482
	2		222	222
	3		464	623
	4		832	1,140
	5		492	492
	6		316	758

Substation	Feeder	Peak Load	Minimum	Daytime Minimum
Kenrick (26)	Substation	7,294	2,149	2,820
	1		53	53
	2		601	690
	3		306	396
	4		986	1,132
Ritter Park (27)	Substation	16,837	3,077	3,907
	2		189	189
	3		570	570
	4		372	538
	5		257	388
Nininger (29)	Substation	3,315	616	847
	1		117	216
	3		226	268
	4		120	180
Ravenna (30)	Substation	7,680	652	721
	1		0	0
	3		293	342
	4		152	167
Burnscott (31)	Substation	11,656	1,556	2,520
	1		367	367
	2		455	588
	3		404	513
Randolph (32)	Substation	3,308	< 0	< 0
	1		133	161
	2		87	87
	3		< 0	< 0
	4		14	20

Appendix C – Non-Wires Solution RFI

February 2019

Integrated Distribution Plan

Table of Contents

1. Introduction

Dakota Electric Association (Dakota Electric), in conjunction with the development of their Integrated Resource Plan, is soliciting information from qualified and experienced venders (Respondents) with the experience to deliver innovative Non-Wires Solutions, (NWS), within Dakota Electric's service territory addressing common distribution system issues. Dakota Electric will be incorporating the generalities of Respondents' responses into their Integrated Distribution Plan filing to the State of Minnesota Public Utilities Commission.

From the responses provided, Dakota Electric expects to identify a selected subset of the proposed NWS(s) to better refine the capabilities and possible limitation of the proposed solutions. This is envisioned to be through additional interaction with the vendor. If one or possibly more of the proposed NWS(s) appear to meet the reliability and economic levels for consideration, Dakota Electric is planning to bring one or more of the proposed solutions forward for implementation in the field. Prior to committing to any implementation, Dakota Electric would need to obtain Dakota Electric Board approval. Depending upon the nature of the proposed solution, Dakota Electric may need to go through a formal RFP process for any final solution.

Respondents are asked to clearly identify which portions of their RFI response is confidential. Simply marking the entire proposal as confidential may restrict Dakota Electric from using that entire proposal as a potential NWS. Dakota Electric is required to provide information about the designs for government permitting and for reporting within filings such as the IDP.

2. Background

Dakota Electric is the second largest member-owned distribution electric cooperative in Minnesota serving approximately 106,835 members. Located adjacent to southeast side of Minneapolis-St. Paul metro area, the cooperative membership is comprised of 58% residential and agricultural accounts, 41% commercial accounts and 1% irrigation and street lighting accounts. Dakota Electric is a progressive electric utility currently implementing its Advance Grid Infrastructure (AGi) project which will enhance the communications and operation of Dakota Electric's distribution system.

3. RFI Purpose

Dakota Electric is issuing this Request for Information (RFI) for four different Problem Statements of common electric distribution issues that have occurred within Dakota Electric's service territory. Responses to the RFI should include NWS utilizing Distributed Energy Resources (DER) such as:

- Distributed Generation – non-fossil fuel preferred
- Energy Storage

- Demand Side Management
- Other resources that may be able to meet the scenario conditions needs[3]

Dakota Electric will be using responses to the RFI to expand its knowledge base of possible solutions that may better address distribution issues than traditional distribution construction solutions. Depending on the RFI responses, Dakota Electric may also be releasing a formal Request for Proposals (RFP) in the future to implement select NWS(s).

The generalities of the responses to the RFI will be incorporated in Dakota Electric's Integrated Distribution Plan filing to the State of Minnesota Public Utilities Commission.

4. Guidelines to Respondents

Dakota Electric requests all Respondents to address all of the information requirements listed in an individual Problem Statement. Respondents do not need to respond to all four Problem Statements. Respondents shall clearly state all assumptions they make about the meaning or assumptions made about each Problem Statement. The more information about the capability and potential limitations of the proposed NWS(s) provided by the Respondent is appreciated. Providing specific answers to each of the questions listed for the Problem Statement is critical for the review of the response. Reasonable budgetary estimates or ranges of NWS(s) are expected to provide Dakota Electric with a basis of economic comparison. All Problem Statement responses should be realistic and examples of references where similar NWS have been deployed is appreciated.

Dakota Electric will keep individual Respondent's submissions confidential and instead use generalities of Respondent's NWS(s) in its filing to the State of Minnesota Public Utilities Commission. Respondents may provide their responses in their preferred format. Respondents are not required to provide solutions to all of the listed Problem Statements in their submission to Dakota Electric.

Questions or clarifications regarding this RFI may be directed to Kristi Robinson at krobinson@star-energy.com.

5. Timeline for RFI

The timeline milestones for this RFI will be as follows:

- February 15, 2019: Dakota Electric Release of RFI
- March 1, 2019: Cutoff for Respondents' questions regarding RFI to Dakota Electric
- March 7, 2019: Dakota Electric's responses to Respondents' questions

[3] Dakota Electric will not consider Energy Efficiency (EE) options for this RFI. Dakota Electric is experienced in EE deployments and considered adoption of both solutions at a mature adoption level within Dakota Electric's service territory.

- March 15, 2019: RFI responses due to Dakota Electric
- March 30, 2019: Respondents of NWS projects identified for additional research will be notified
- November 1, 2019: Dakota Electric's Integrated Distribution Plan filing to State of Minnesota Public Utilities Commission

6. RFI Submission Requirements

All RFI response submission from Respondents must be received by Friday, March 15, 2019 at 5 p.m. (CST). Submission in electronic form is preferred. Emails are limited to 5 MB and an option for an FTP site upload is also possible provided Respondents requests the FTP site access information prior to the RFI submission deadline. Responses and questions should be directed to the attention of:

Kristi Robinson, P.E.
Manager, Rates & Regulations
STAR Energy Services LLC
krobinson@star-energy.com
6841 Power Lane SW, Alexandria, MN 56308

Dakota Electric will only be including generalities of possible NWS in its filing to the State of Minnesota Public Utilities Commission. However, Respondents shall clearly mark specific portions of their RFI response that is considered confidential information. Simply marking the entire proposal as confidential may restrict Dakota Electric from using that entire proposal as a potential NWS. Dakota Electric is required to provide information about the designs for government permitting and for reporting within filings such as the IDP.

Dakota Electric reserves the right to not consider any and all responses, for any reason, and not include them in any further discussion or consideration. Further Dakota Electric also reserves the right to not include information about any RFI response, for any reason, within Dakota Electric IDP filing to the State of Minnesota Public Utilities Commission.

7. Problem Statements

The following Problem Statements are intended to be very general. These Problem Statement were written to provide the Respondent with some information about the common conditions Dakota Electric faces when deciding investment options to improve the distribution system in support of new or changing electrical demand. As the goal of this RFI is to learn about possible NWS(s), the Problem Statements were kept general to prevent automatic elimination of possible NWS(s).

The information provided in the Problem Statement is similar in detail to what is provided to the electric utility for a new or changing load(s). Rarely is detailed daily, weekly or seasonal load shapes provided to the electric utility for a new or changing load(s). While these Problem Statement are not very specific, this does reflect the reality of distribution planning.

When responding to these Problem Statements, it would be reasonable for the Respondent to assume residential, commercial or a mix of these load shapes. Respondents are asked to list their assumptions made for each Problem Statement, including the load shapes assumed. It is also reasonable for the Respondent to provide in their response which type of load curve the proposed NWS would best work for and why the proposed NWS would work better for one type of load curve versus another. The Problems Statements include ranges of conditions. Respondents are to identify which part of the range(s) their proposed NWS(s) are designed to meet. All NWS(s) for any of the range conditions will be initially considered. In general, we ask that the Responder provide Dakota Electric with information about the potential limitations of the proposed NWS(s).

8. Problem Statement A – Limited Main Circuit Capacity

Dakota Electric has a specific area where the existing distribution electric infrastructure is not robust enough to supply the entire peak electrical needs of a growing electrical demand. During times of peak demand, the voltage cannot be maintained within acceptable power quality limits. Currently, peak periods last for 1 - 2 hours, is around 200 - 500 kW of excess demand and occur only 5 – 10 times per year. Growth in the amount of the underserved load is occurring and the duration and frequency of the peak load is increasing.

Scenario A1 – Assume the Problem Statement is occurring in a suburban area, with projected 2 - 3% annual growth for five years. Land availability is scarce and prices for available land is very expensive, (i.e., sold by the square foot). After five years the underserved load is forecasted increase from 200 – 500 kW and to be 1 - 2 MWs, last for 4 - 5 hours, and occur 5 - 10 times per month during the summer months and could occur 1 - 3 times per month during the other months, specifically winter months.

The typical, traditional wired solution for Scenario A1 would be to rebuild the main circuits with a larger conductor or to build an additional circuit into the area.

Scenario A2 – Assume the Problem Statement A is occurring in a rural area, with slow growth over a long period of time. Annual growth is expected at 0.1% for many years. Land availability and cost is reasonable, (i.e., sold by the acre and is normally converted from agricultural fields). After five years the underserved load is expected to change from 200 – 500 kW and be 400 - 600 kW and last for 3 - 5 hours and occur 10 - 15 times per year, mostly during summer months.

The typical, traditional wired solution for Scenario A2 would be the application of voltage regulators. Or, if the addition of regulators is not sufficient, to rebuild the main circuits with a larger conductor.

Responses

For each of this Problem Statement's two scenarios, please provide a description of a proposed Non-Wires Solution, (NWS). In addition to the description for the proposed NWS(s), please provide answers for the following questions for each of the scenarios.

Installation

1. What equipment is required to implement the proposed NWS(s)?
2. What are the installation requirements for the equipment?
3. What is the procurement, design and installation time frame for the proposed NWS(s)?

Operations and Maintenance

4. What are the maintenance requirements for the proposed NWS(s)?
5. How often are outages required for maintenance?
6. How long would maintenance outages take the NWS(s) out of service?
7. Are there any environmental issues or decommissioning costs to the NWS(s)?

Performance

8. What level of availability of performance requirement could the NWS(s) meet, (i.e., 98% availability or up-time)?
9. What is the expected life for the equipment required to provide the proposed NWS(s)?
10. Are there options for rejuvenation of the NWS(s) to extend its expected life or can the NWS(s) be "made new again" at the end of its expected life?
11. If Question 10 is yes, what is required to rejuvenate the proposed NWS(s) and what is the budgetary cost?
12. Where has the proposed NWS(s) been utilized?

Costs

13. What is the budgetary cost for the proposed NWS(s), if purchased outright by Dakota Electric?
14. What is the budgetary cost for the proposed NWS(s), if provided by a third-party in a lease-arrangement or power purchase agreement with Dakota Electric?
15. What are the expected annual operating costs?

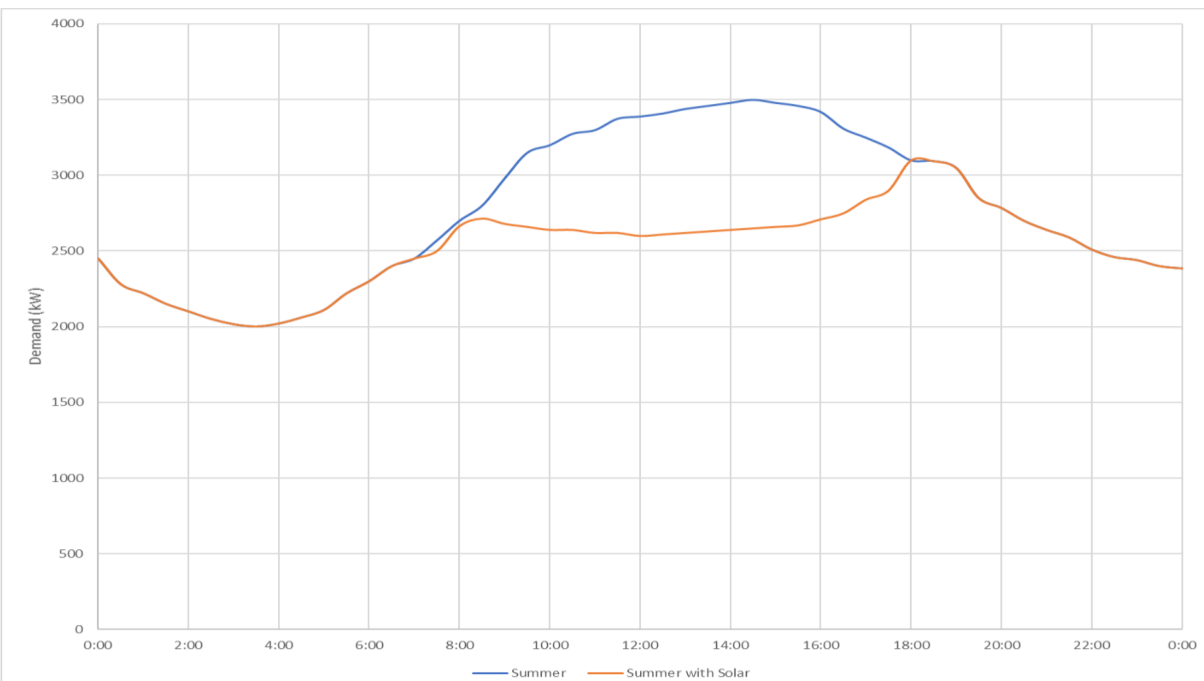
9. Problem Statement B – Serving New Load

Dakota Electric has a new residential development for a specific area. The existing electrical infrastructure is not sufficient to supply the majority of the additional new load. Possible solution(s) need to be redundant and robust to ensure a reliability supply of electricity. Possible solutions(s) must also allow for portions of the solution to be out of service for maintenance.

For Problem Statement B, assume the new load is residential and has a daily minimum load level around 2.0 MW and a peak demand of 3.5 MW. The initial daily summer load curve is expected to be similar to the orange line on the graph shown in Figure 1. Due to solar interests by potential new load(s) in the area, there exists the possibility that some of the buildings within the development may install solar. Given significant penetration of solar installations, the daily summer load curve is expected to be similar to the blue line on the graph shown in Figure 1.

The typical, traditional wired solution for Problem Statement B would be to extend a new distribution circuit, or circuits, to the new development or large commercial load.

Figure 1. Problem Statement B – Expected Load Curves



Responses

For this Problem Statement, please provide a description of a proposed Non-Wires Solution, (NWS). In addition to the description for the proposed NWS(s), please provide answers for the following questions for Problem Statement B.

Installation

1. What equipment is required to implement the proposed NWS(s)?
2. What are the installation requirements for the equipment?
3. What is the procurement, design and installation time frame for the proposed NWS(s)?

Operations and Maintenance

4. What are the maintenance requirements for the proposed NWS(s)?
5. How often are outages required for maintenance?
6. How long would maintenance outages take the NWS(s) out of service?
7. Are there any environmental issues or decommissioning costs to the NWS(s)?

Performance

8. What level of availability of performance requirement could the NWS(s) meet, (i.e., 98% availability or up-time)?
9. Can the NWS(s) be scaled in size, and if so, scalable to what capacity, (i.e., can multiple units of the NWS be added for a load that is ten times in size)?
10. What is the expected life for the equipment required to provide the proposed NWS(s)?
11. Are there options for rejuvenation of the NWS(s) to extend its expected life or can the NWS(s) be “made new again” at the end of its expected life?
12. If Question 11 is yes, what is required to rejuvenate the proposed NWS(s) and what is the budgetary cost?
13. Where has the proposed NWS(s) been utilized?

Costs

14. What is the budgetary cost for the proposed NWS(s), if purchased outright by Dakota Electric?
15. What is the budgetary cost for the proposed NWS(s), if provided by a third-party in a lease-arrangement or power purchase agreement with Dakota Electric?
16. What are the expected annual operating costs?
17. If it is possible to increase the capacity of NWS(s), would cost also grow linear by capacity or in another manner, (see Question 9)?

10.Problem Statement C – Contingency Support

Dakota Electric has a portion of its service territory in which the existing distribution system can adequately serve the existing load under normal operating conditions. During peak loading conditions, when the distribution system is in abnormal operating conditions, (i.e., failed or damage portions of the distribution system resulting in reconfiguration of the distribution system), this portion of the electrical load cannot be adequately served as contingency configuration options for the distribution system and do not provide enough capacity to serve the entire load. Abnormal operating conditions could last up to seven consecutive days.

Scenario C1 – Assume amount of underserved load is 500 kW and the duration of that peak load is 4 - 6 hours per day, during the abnormal operating conditions. Past experience has shown that these abnormal operating conditions have a low to medium probability of occurring, (occurrence may happen once in a seven-year span.)

Scenario C2 – Assume amount of underserved load is 1 - 2 MW and the duration of that peak load is 6 - 8 hours per day, during the abnormal operating conditions. Past experience has shown that these abnormal operating conditions have a fairly high probability of occurring, (occurrence may happen once every two years.)

The typical, traditional wired solution for both scenarios of Problem Statement C would be to upgrade existing distribution circuits and/or upgrade neighboring substations to the area.

Responses

For each of this Problem Statement's two scenarios, please provide a description of a proposed Non-Wires Solution, (NWS). In addition to the description for the proposed NWS(s), please provide answers for the following questions for each of the scenarios.

Installation

1. What equipment is required to implement the proposed NWS(s)?
2. What are the installation requirements for the equipment?
3. What is the procurement, design and installation time frame for the proposed NWS(s)?

Operations and Maintenance

4. What are the maintenance requirements for the proposed NWS(s)?
5. How often are outages required for maintenance?
6. How long would maintenance outages take the NWS(s) out of service?
7. Are there any environmental issues or decommissioning costs to the NWS(s)?

Performance

8. What level of availability of performance requirement could the NWS(s) meet, (i.e., 99.998% availability or up-time), during the abnormal operating conditions?
9. What is the expected life for the equipment required to provide the proposed NWS(s)?
10. How is NWS(s) affected by the capacity size of the underserved load?
11. How is NWS(s) affected by the duration of the abnormal operating conditions?
12. Where has the proposed NWS(s) been utilized?

Costs

13. What is the budgetary cost for the proposed NWS(s), if purchased outright by Dakota Electric?
14. What is the budgetary cost for the proposed NWS(s), if provided by a third-party in a lease-arrangement or power purchase agreement with Dakota Electric?
15. What are the expected annual operating costs?

11. Problem Statement D – Mobile Solution

During times of emergency or planned maintenance, specific portions of the distribution system need to be supported due to maintenance outages or storm damage. The assumption is 500 kW of generation would be adequate to provide the necessary support for the affected area. NWS(s) would need to be a trailer mounted generation source which could be driven to a site.

Scenario D1 – Assume the 500 kW of generation support is required for 24 hours a day for several consecutive days. The mobile NWS will be interconnected to distribution system to support the area.

Scenario D2 – Assume the 500 kW of generation support is required for 24 hours a day for several consecutive days. The mobile NWS will be interconnected to an electrical island, (i.e., microgrid), and will be the sole electrical supply for the load.

The typical solution for both scenarios of Problem Statement D, would be a fossil fuel generator mounted on a trailer.

Installation

1. How would this solution be interconnected to the distribution system or the electrical island?
2. What would be the approximate weight of the mobile NWS and the length of the trailer?
3. What additional equipment is required to interconnect the proposed NWS(s)?
4. What are the installation requirements for the equipment?

5. What is the procurement, design and installation time frame for the proposed NWS(s)?

Operations and Maintenance

6. What are the maintenance requirements for the proposed NWS(s)?
7. How often are outages required for maintenance?
8. How long would maintenance outages take the NWS(s) out of service?
9. Are there any environmental issues or decommissioning costs to the NWS(s)?

Performance

10. What level of availability of performance requirement could the NWS(s) meet during its continuous operating conditions and how long of a duration, (i.e., 99.998% availability or up-time for 300 hours)?
11. Can the NWS(s) be scaled in size, and if so, scalable to what capacity, (i.e., can multiple NWS trailers be integrated together to serve a load that is ten times in size or can the capacity of the NWS on a single trailer be increased)?
12. What is the expected life for the equipment required to provide the proposed NWS(s)?
13. Are there options for rejuvenation of the NWS(s), to extend its expected life, or can the NWS(s) be "made new again" at the end of its expected life?
14. If Question 13 is yes, what is required to rejuvenate the proposed NWS(s) and what is the budgetary cost?
15. Where has the proposed NWS(s) been utilized?

Costs

16. What is the budgetary cost for the proposed NWS(s), if purchased outright by Dakota Electric?
17. What are the expected annual operating costs?
18. If it is possible to increase the capacity of NWS(s), would cost also grow linear by capacity or in another manner, (see Question 11)?

Appendix D – 2019 Capital Construction Projects > $50,000

2019 Capital Construction Projects (greater then $50,000)					
Project Description	**DEA Project Reason**	**PUC IDP Category**	**Project Identified in 2019 Budget**	**Project Started**	**Completion**
Denmark Ave #4 ACSR to 3ph 477 ACSR Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2019	2019
Essex Ave #4 to 1ph-1/0 Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2019	2019
Northfield Blvd #4 to 1/0 Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2019	2019
265th Street East #4 to 1/0 Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2019	2019
Northfield Blvd (north) #4 to 1/0 Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2019	2019
Blaine Ave #4 to 1/0 Pole and line replacement	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	Delayed till 2020	
CSAH 23 Foliage Ave - Overhead relocation and conversion	Road Construction	Project related to government requirement	Y	2019	2019
CSAH 42 Rebuild - 3ph 1/0 (adding trail)	Adding walking trail	Project related to government requirement	Y	2019	2019
CSAH 50 Conversion 1PH OH to URD (Adding Turn Lanes)	Road Construction	Project related to government requirement	Y	2019	2019
CSAH 78 Rebuild 3PH & 1PH - relocation	Road Construction	Project related to government requirement	Y	Delayed till 2020	
CSAH 9 & Flagstaff Ave Rebuild for new roundabout	Add Roundabout	Project related to government requirement	Y	2019	2019
Johnny Cake Ridge Rd - 3PH 336AL to 477 ACSR - rebuild	Road Construction	Project related to government requirement	Y	2019	2019
State Hwy 47 Rebuild (Donnelly to 240th) - rebuild	Road Construction	Project related to government requirement	Y	2019	2019
3PH URD along 135th Street (Eliminate back lot line overhead circuit)	Reliability	System Expansion or Upgrades for Reliablity	Y	2019	2019
Casper Ave from Aggrate to Hwy 47 3-PH #4 to 3ph-477 ACSR	Capacity - upgrade	System Expansion or Upgrades for Reliablity	Y	2019	2019
Lebanon Hills Transmission line conversion 69kV to 115kV	Transmission Rebuild	System Expansion for Capacity and Reliability	Y	2019	2019
Lebanon Hills Feeder Exits & rebuild Substation - 69kV to 115kV	Transmission Rebuild	System Expansion for Capacity and Reliability	Y	2019	2019
Transmission line rebuild along Cliff Rd - and Hwy 13	Transmission Rebuild	System Expansion or Upgrades for Reliablity	Y	2018	2019
Replacement of Power Operated PMH Units - Several Units	Age related	Age-Related Replacement & Asset Renewal	Y	2018	2019
Replacement of SCADA Radio Communication - Phase 1	Age related - Cyber Security	Age-Related Replacement & Cyber Security	Y	2018	2019
Replace Substation Communication Tower	Age related	Age-Related Replacement & Asset Renewal	Y	Delayed till 2020	2020
Conversion OH to URD - Travelers Trail	Members Request	Other	N	2019	2019
Installation of Fiber communication for Substations	Communication - Capacity	Grid Modernization and Pilot Projects	Y	2016	2020
Conversion OH to URD - 172nd Street	Member Request	Other	N	2019	2019
C/R Burnsville Reservoir	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Inga Ave P#'s 26396, 11839	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Hidden Ponds	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Diamond Path 5th	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Kennedey 1st	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Southcross Estates 1st , 2	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Oak Shores 6th, 7th	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Safari Estates 1st	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Nordic Woods 1st, 2nd, 4th	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
C/R Basset 2nd and 3rd	Cable Replacement	Age-Related Replacment & Asset Renewal	Y	2019	2019
Development - Cedar Crossings	Development	New Service	N	2019	2019
Development - Meadow Ridge 1st phase	Development	New Service	N	2019	2019
Development - Meadow Ridge 2nd phase	Development	New Service	N	2019	2019
Development - Avonlea 4th	Development	New Service	N	2019	2019
Development - Summerlyn 8th	Development	New Service	N	2019	2019
Development - Knob Hill of Lakeville	Development	New Service	N	2019	2019
Fischer East Substation Bkr Replacement	Substation Equipment	Age-Related Replacment & Asset Renewal	Y	2018	2019
3MW Solar Line Extension & Interconnection & Monitoring	DER Interconnection	Other	Y	2019	2019
2MW Solar Interconnection and SCADA	DER Interconnection	Other	Y	2018	2019
Well #9 - C&I Interruptible Interconnection & SCADA	DER Interconnection	Other	N	2018	2019
AGI outdoor test area (Dakota Electric Pole yard)	AGi Project	Grid Modernization and Pilot Projects	Y	2018	2019
AGi Meter Exchange (SAT)	AGi Project	Grid Modernization and Pilot Projects	Y	2019	Scheduled for 2021

Appendix E – Proposed Capital Construction Projects 2020 > $50,000

2020 - 2023 Capital Construction Projects estimated greater then $50,000					
Project Description	**DEA Project Reason**	**PUC IDP Category**	**Project Identified in 2020 Budget**	**Expected Project Start**	**Estimated Completion**
Replacement of lines with old poles > 60 years Blanket Project	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2020	2020
(Team is working on identifying the actual projects and their costs)					
Cnty 70 – Kenrick Ave/Kensington Blvd/CSAH-23 - rebuild	Road Construction	Project related to government requirement	Y	2020	2020
Cable Replacement Projects - Blanket Project	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2020	2020
(Team is working on identifying the actual projects and their costs)					
Cnty 78 / 10 - Blaine Ave - Rebuild	OH Line Replacement - Age	Age-Related Replacement & Asset Renewal	Y	2020	2020
Cnty 73 / Akron - Rebuild	Road Construction	Project related to government requirement	Y	2020	2020
CP 62-26 - adding roundabout	Road Construction	Project related to government requirement	Y	2020	2020
Cimarron Road - Backlot line conversiond	Reliability	Project related to government requirement	Y	2020	2020
Garden View - Backlot line conversion	Reliability	Project related to government requirement	Y	2020	2020
Burnscott Transformer replacement (increase capacity)	Substation Capacity	System Expansion for Capacity and Reliability	Y	2020	2020
New Circuit - Burnscott Substation	New Feeder - Capacity	System Expansion for Capacity and Reliability	Y	2020	2020
Lebanon Hills Transmission line conversion 69kV to 115kV	Transmission Rebuild	System Expansion for Capacity and Reliability	Y	2019	2020
Lebanon Hills Feeder Exits & rebuild Substation - 69kV to 115kV	Transmission Rebuild	System Expansion for Capacity and Reliability	Y	2019	2020
Replacement of Radio Communication - Phase 2	Age related - Cyber Security	Age-Related Replacement & Cyber Security	Y	2020	2020
Replace Communication Tower	Age related	Age-Related Replacement & Asset Renewal	Y	2020	2020
AGi Meter Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2019	2021
AGi Load Control Receiver Exchange	AGi Project	Grid Modernization and Pilot Projects	Y	2019	2023
RF Mesh Installation	AGi Project	Grid Modernization and Pilot Projects	Y	2019	2020
2021					
Barnes Grove Substation (new)	Substation Capacity	System Expansion for Capacity and Reliability	Y	2021	2021
Project not approved - plan on asking for board approval Nov. 2020					
2021-2022 Estimated dates					
Dodd Park Substation second transformer	Substation Capacity	System Expansion for Capacity and Reliability	Y	2021	2022
Project not approved - plan on asking for board approval Nov. 2020					
2023-2024 Estimated dates					
New Substation Elko	Substation Capacity	System Expansion for Capacity and Reliability	Y	2023	2024
Project not approved, need Board approval and design and permitting					

Appendix F – Residential and Commercial IDP Survey

The following are the main questions with the results from the <u>RESIDENTIAL</u> survey that was conducted during the event at the Minnesota State Zoo.

"How much more would you be willing to pay on your electric bill for Dakota Electric to invest in renewable energy?"

Table shows the percentages of the respondents selected one of the selections.

Nothing More	15%
Up to 5% more	33%
Up to 10% more	26%
Greater than 10% more	9%
Don't Know	17%

"On a scale of 1 to 5, with 1 being least important to and 5 being most important to you please rank the following issues".

The following is the average number for each of the selections. The selections have been sorted by the most important to the least important. Cost of Power being ranked the lowest in importance does not align with what Dakota Electric has been hearing from most of the membership. This reflects the nature of how the survey was conducted.

	Average Number
Renewable Energy	3.21
Reliability	3.03
Safety	3.00
Choice of Power Supplier	2.99
Cost of Power	2.93

"What is the likelihood that you will install a solar array at your home in the next couple of years"

Definitely will	8%
Probably will	12%
May or may not	29%
Probably will not	29%
Definitely will not	23%

"If you don't plan on installing a solar array at your home, which of the of the following are reasons? (<u>check all that apply</u>)."

System Cost	44%
Lack of appropriate rooftop space	14%
Uncertainty around permitting and installation	17%
Lack of information	22%
Other	21%

For those selecting "Other" the following are some of the types of responses that were written in.

- Renting / don't own my home
- Planning on moving
- Too old
- No space available
- Zoning or rules will not allow installations

"Do you anticipate purchasing an electric vehicle within the next 5 years?

Definitely will	9%
Probably will	11%
May or may not	37%
Probably will not	29%
Definitely will not	14%

Similar survey questions were asked of some of the larger electrical users, all of which were commercial or industrial accounts. Dakota Electric Business Executives contacted some of the larger users and asked the following questions for the <u>commercial and industrial surveys</u>.

The following are the main questions with the results from the <u>COMMERCIAL AND INDUSTRIAL</u> survey.

"On a scale of 1 to 5 how important is it to you that utilities provide "green power" from renewable energy sources?"

Not Important at all = 1	1%
2	3%
3	24%
4	51%

Extremely important = 5	19%

"On a scale of 1 to 5, with 1 being least important to you and 5 being most important to you, please rank the following issues."

	Average Number
Reliability	3.27
Safety	2.78
Cost	2.70
Renewable	2.14
Choice of Power Supplier	1.68

"How much more would you be willing to pay on your electric bill for Dakota Electric to invest in renewable energy?"

Nothing More	5%
Up to 5% more	14%
Up to 10% more	16%
Greater than 10% more	43%
Don't Know	22%

"What is the likelihood that your organization will install a solar array in the next couple of years?"

Definitely will	6%
Probably will	6%
May or may not	32%
Probably will not	32%
Definitely will not	24%

"If you don't plan on installing a solar array, which of the following are reasons? (check all that apply)"

System Cost	46%
Lack of appropriate rooftop space	19%
Uncertainty around permitting and installation	14%
Lack of information	19%
Other	22%

"Does your company anticipate investing in electric vehicles within the next 5 years?"

Definitely will	3%
Probably will	8%
May or may not	27%
Probably will not	49%
Definitely will not	13%