June 21, 2017

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

Subject: ***Dakota Electric Association Comments in Response to Notice of Comment Period on Distribution System Planning Efforts and Considerations Docket No. E-999/CI-15-556***

Dear Mr. Wolf:

On April 21, 2017, the Minnesota Public Utilities Commission (Commission) issued a Notice of Comment Period on Distribution System Planning Efforts and Considerations (Notice) in the above-referenced docket. This Notice included a questionnaire on matters related to distribution system planning with questions divided into the following three sections:

A. How do Minnesota utilities currently plan their distribution system?

B. What is the status of each utility's current plan?

C. Are there ways to improve or augment utility planning processes?

The Notice requires responses from regulated investor-owned electric utilities and encourages responses from municipal and cooperative utilities.

Enclosed are Dakota Electric Association (Dakota Electric or Cooperative) responses to questions raised in Sections A and B of the questionnaire.

Dakota Electric looks forward to these continuing discussions on distribution system planning. If there are any questions about these comments, please contact Craig Turner at 651-463-6xxx or me at 651-463-6258.

Sincerely,
/s/ Douglas R. Larson
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STATE OF MINNESOTA

BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

NOTICE OF COMMENT PERIOD ON DISTRIBUTION SYSTEM PLANNING EFFORTS AND CONSIDERATIONS	DOCKET NO. E-999/CI-15-556 JUNE 21, 2017

COMMENTS OF DAKOTA ELECTRIC ASSOCIATION
QUESTIONNAIRE SECTIONS A AND B

Introduction

The existing Dakota Electric distribution system has performed well for our Members for many years. Dakota Electric has worked hard to provide safe and reliable electrical service for our Members, while maintaining a balance between reliability and economics. The costs associated with the construction, operation and maintenance of an electrical distribution system does not represent the majority of the Member's monthly bill, however, it is the main portion of the monthly bill that is under the direct control of Dakota Electric Association. Therefore, Dakota Electric takes the planning and selection of new distribution infrastructure and the costs associated with this construction very seriously.

Dakota Electric works with our Members, local governmental authorities, other electrical utilities, various national organizations and our employees to identify and evaluate better ways to reduce overall costs and improve the electrical services to our Members. With the expected life of most of the Dakota Electric infrastructure exceeding 30 years, the design and installation of new distribution facilities must have the future in mind.

With our answers to the following questions on distribution planning processes and procedures, we do not want to give the impression that the distribution planning process is a prescribed and fixed process. While we strive to predict the future development and growth within our service territory, our forecasts are just that, forecasts. Our long range planning studies provide a framework for development of the distribution system, but the specifics of what is built, is in response to actual development and events.

The forces driving the development of the distribution system are fluid and dynamic. The lead times for acquiring major electrical distribution equipment are long and the changes in the electrical usage for a given portion of the electrical system can be dynamic. Utilities are given little time to respond to requirements for rebuilding portions of the distribution system due to roadway modifications or adding new loads. Therefore, utilities require flexibility in order to respond to these needs.

As many of the major pieces of electrical equipment used by utilities are not available as off the shelf commodities, the lead times for this equipment is very long. To allow the utilities to be able to quickly respond to the consumer's needs, utility specific equipment standards have been developed which help reduce the procurement timeline for major equipment. As utilities look at using new technologies to offset traditional distribution system construction, standardized options will need to be developed. These standard solutions allow the utility engineer to quickly select and then procure the required equipment. Also, since each utility's distribution system design and service territory has unique features, the standardized options may need to be customized to work with each utility's system.

As the Commission works through the review of distribution planning to identify ways to help support grid modernization, Dakota Electric recommends that the focus is on outcomes rather than creating a prescriptive process. Utilities require flexibility to allow them to be responsive to the needs of their consumers and to support the changes driven by the cities, counties and other governmental agencies. The sharing of effective solutions among utilities should be encouraged.

Section A
How do Minnesota utilities currently plan their distribution systems?

Please describe the following items with respect to current distribution system planning efforts:

1) The distribution planning resources utilized by utilities, including:

a. Types of modeling software used and for what specific purpose

Dakota Electric uses the Engineering Analysis software called WindMil, which was developed by Milsoft Utility Solutions. WindMil Analysis is used for all of the distribution system studies, including the annual, periodic and long range planning studies, sectionalizing, contingency, generation interconnection and other studies. In addition an Esri based Geographic Information system (GIS) coupled with custom software is used to perform transformer loading studies and other engineering analysis.

b. Applicable engineering standards

Dakota Electric follows the National Electric Safety Code (NESC), the applicable American National Standards Institute (ANSI) and Institute of Electrical and Electronics Engineers (IEEE) standards and continues to follow many of the Rural Utilities Service (RUS) bulletins, which outline many of the planning procedures. The RUS bulletins are an excellent set of documents which are used across the United States by electrical Cooperatives of all shapes and sizes.

c. *Personnel commitment: including utility personnel as well as contracted services and an overview of their roles and responsibilities*

Dakota Electric has four engineers which each spend a portion of their time studying the electrical system. Consultants are also used at times to assist or complete analysis of the distribution system. Historically for the longer range, more complex studies Dakota Electric utilizes consultants to help off-set the labor required to perform the study. The use of external consultants also provides an infusion of knowledge and methods learned from other utilities through the consultants experience and insight.

d. System visibility and data availability: At what circuit levels and over what time intervals is data collected? If possible, provide an example of the range of data collected and available.

All of the Dakota Electric circuits (feeders) leaving the distribution substations are monitored in real-time by the Supervisory Control and Data Acquisition (SCADA) system. Dakota Electric monitors and stores the phase amps, watts and vars for all of the substation feeders and overall substation transformers. Dakota Electric also monitors and stores the substation buss voltages. This data is stored for at least the past 2 years in our historical data system. The interval of this data storage is at least every 5 minutes for these values and in many cases the data is recorded on a minute by minute basis. Great River Energy, our transmission and power supplier, monitors all of our substation delivery points and has hourly energy data stored for each substation delivery point.

e. Percentage of substations and feeders are equipped with SCADA

100% of the Dakota Electric substations and feeders are equipped with SCADA control and monitoring of the power flow through the substation and feeders.

f. Form of hosting capacity software or analysis, if any, used in the planning process and to conduct interconnection

Dakota Electric has not needed to acquire specialized hosting analysis software and develop a system model required for that specialized software. Our existing Engineering Analysis software allows us to review and analyze the individual DG interconnection applications we are receiving. So far, we have been able to personally speak and meet with parties interested in interconnecting distributed generation to the Dakota Electric distribution system. For distributed generation installations we have been able to personally work with the Member or their installer, as necessary, to work through the interconnection details and issues that arise.

2) An overview of planning schedules and process, including:

a. Frequency in which the utility conducts distribution system planning

The distribution system planning occurs in three basic time frames.

- Annual Planning
  Annual Distribution Planning Studies are completed to support the annual capital construction budget. Dakota Electric creates a distribution system model which reflects the expected peak summer loads for each of the substations and feeders. The model identifies where the system may be insufficient in terms of service quality or capacity to supply the projected peak summer loads. For each of the service quality and/or capacity issues identified a plan to resolve the issue is developed and the required capital project(s) are created. In some cases, alternative plans are possible and they are evaluated, and compared. Additional capital projects are typically required to rebuild existing circuits in response to city and county road rebuilds. Road rebuilds are when the road right-of-way is widened or the utilization of the existing road right-of-way is modified. This includes increasing shoulders, adding turn lanes, additional lanes, bike lanes, bus lanes, walking paths etc. These distribution system reconstruction projects are added to the distribution model and the estimated costs are added to the annual capital budget.

  While the Dakota Electric system is overall a summer peaking system, where the peak load is driven by air conditioning loads, there are portions of the distribution system which experience peak load outside of the summer period. These areas are periodically studied as they grow and change to ensure the distribution system supplying them has enough capacity to meet the needs. These additional area specific studies are normally completed as part of the annual planning process. Examples of these areas which require specialized studies include ski areas and large commercial / industrial locations where the load is not dependent upon the temperature, but rather is driven by commercial events and/or manufacturing production levels.

- Periodic Planning
  Periodic Distribution Planning Studies are completed as necessary, to resolve engineering and operational issues or to support new developments and/or large loads which can "pop-up". Also, quite often, city or county road rebuild project's scope or design can change or new road projects are added during the year. Road projects plans are changed when the cities and counties respond to new development or project funding changes. When these changes occur, Dakota Electric is required to quickly study rebuilding a portion of our system in support of the new or adjusted road construction project. These periodic studies look at specific portions of the system which are directly impacted by new large load changes or recently released road rebuilds. These studies are required to be completed very quickly, typically in a week or two, to allow the required changes to be designed and the equipment (poles, wire, cable) to be identified and ordered. The lead times for electrical equipment are months and with new large commercial loads able to be permitted and constructed in just a few months, Dakota Electric is required to respond quickly.

  Both the annual and the periodic distribution planning studies include an evaluation of the area development for many years. The goal is to identify distribution system changes which will satisfy the immediate needs but also support the future long term growth of the area. The engineers are looking for the best value for the members, which will provide a reliable distribution system at the lowest overall cost. These studies look at developing both the most effective local area circuit additions and the long term overall system configuration. These studies also involve reviewing the distribution system infrastructure, such as the feeder circuits and substation capacity levels and possible modifications.

- Long Range Planning
  A Long Range Planning study is completed about every 10 years. Overall growth affects the timing of this study. Limited growth will extend the time between studies, while rapid growth will reduce the time between studies. The long range plan identifies the major system improvements, such as new substations and/or major circuits, which will provide the best long term value for our members. The economics and the ability to maintain or improve the reliability for our members are considered as part of the solution.

  As part of completing the long range studies, Dakota Electric meets directly with the area planners representing the cities and counties within the service territory. The transportation plans and the long range plans for these governmental agencies are included as inputs into the Dakota Electric long range study. Dakota Electric works interactivity with Great River Energy and also uses the GRE long range transmission studies as inputs to the Dakota Electric long range study. Collaboratively between GRE and Dakota Electric the overall least cost alternatives for new distribution substations (including both transmission and distribution costs) are identified and reviewed.

b. Frequency of planning updates or revisions: Are updates dependent on a set timing frequency (i.e. every 2, 5, or 10 years) or are there events that may trigger a more frequent planning cycle or revision? If so, please explain.

The annual capital budget is completed on a fixed time frame and is required for the annual capital budget that is approved by the Dakota Electric Board of Directors. The timing for the other two types of planning studies is greatly impacted by actual growth in electrical demand and growth in the circuit loads. For example over the past 8 years, there has been little growth within the service territory and thus there was no need to trigger a Long Range Study of the system to meet new growth.

c. Iterative updates and/or new plans: Are planning processes based on continuations of past plans, new planning cycles, or some combination? How long is each planning cycle's time horizon?

The Annual studies are for construction of projects that are budgeted to occur in that budget year, or the next year. Sometimes the actual construction is delayed due to changes in schedules or changes to the scope of the project. For example the road rebuild project is delayed or canceled or the ramp rate of the new load being interconnected to the system is significantly different than forecasted. The modifications to the distribution system are normally designed to support that portion of the system over the long term and provide for estimated future growth.

The Periodic studies are in response to changes which develop in the load levels or changes in the scope or timing of governmental project plans, which are occurring between the annual studies. These studies are similar in scope as the annual study but focus only at evaluating specific areas of the distribution system which may be impacted. The engineering models used for the Periodic studies are based upon existing distribution infrastructure and are developed directly from our GIS and existing Member usage.

The Long Range Plans provide a development framework (distribution substations and feeders) which is used by the annual and period studies as input. The portions of the long range plan are implemented as they make the most economic sense to serve the area loads. It is typical for the Long Range Plan to include development of 5, 10 and 20 year models of the area to identify the potential issues with supplying the future needs of our Members. The base study model consists of the existing distribution infrastructure. Then the forecasted loads, for the different study periods, are applied to the existing infrastructure model. The portions of the system which are not capable of supporting the forecasted loads are identified and possible alternative solutions are developed. The different forecasted load models (5, 10, 20 years) also help determine the sensitivity or future load level at which the solution will need to be implemented. The identified alternatives are then applied in the models and evaluated and analyzed to ensure they resolve the issues in the future years load models. The identified solutions are compared against each other using reliability, overall cost and constructability to help select the best long term value for serving our Members.

d. Planning elements or considerations included (or not included) in regular updates and revisions and a description of each: For example: circuit or substation data, power flow *analysis, power quality analysis, fault analysis, load and demand forecasts, external policy and regulations, etc.*

The annual studies include a very detailed review of the distribution system. The Dakota Electric engineers model the entire distribution system with the expected peak load for the following year. The distribution model is a complete detailed representation of all the primary electrical system's wires and cables, supplying each of the member's transformers. The requirement is to ensure that there is enough distribution system capacity available, for all of the distribution components, to supply the electrical requirements for all the Member's homes and businesses.

Using the engineering analysis tool with the GIS, the individual distribution transformers are reviewed to ensure adequate capacity to meet the Member's expected needs. Using the engineering analysis and the distribution system model, each piece of equipment and each section of the distribution system, including all of the primary wires, cables, fuses, regulators, reclosers, breakers are reviewed for potential overloading; the protective coordination levels between the fuses, reclosers and breakers is reviewed for proper coordination and operation; the expected primary voltage levels supplied to each member is reviewed to ensure adequate voltage levels to support the member's needs; contingency options are reviewed to ensure the ability to back feed circuits in the event of substation or circuit failure.

As part of our annual reliability study process the worst feeder(s) are identified and this information is included as an input into the annual distribution study for the engineers. Dakota Electric is also consistently looking at our outages and the individual Member's experience to see if we can identify ways to improve their service. Many of these system changes which improve the level of service, especially if minor, do not wait for the next planning studies cycle. The operations area is in consistent communication with the engineers to identify system changes throughout the year. A small part of the capital budget is reserved for these contingencies and other situations that occur, which allow Dakota Electric to quickly resolve these issues.

e. Integration of existing planning processes: Explain to what extent existing planning processes, including resource planning, transmission planning and others studies (i.e. interconnection) are used in the formulation of distribution plans.

The resource planning process is performed by Great River Energy (GRE) for the Dakota Electric service territory. Dakota Electric together with all of the other Great River Energy Member Cooperatives develop a long range load forecast every two years. This Long Range Load Forecast is used as the basis for the forecasted load levels within the Dakota Electric Long Range Plan.

The Long Range Transmission studies are completed by Great River Energy (GRE) in conjunction with other transmission providers in the area and MISO. Dakota Electric's Long Range Load Forecast and Long Range Plan are provided to GRE and used as inputs into the their transmission studies. Results of the GRE transmission studies are provided to Dakota Electric and used as an input into Dakota Electric's studies. Since the Dakota Electric and GRE planning studies are updated on different time tables, each study uses the other as an input. For example Dakota Electric's Long Range Plan is completed using the latest GRE Long Range Transmission study results and then the next GRE transmission study will use the latest Dakota Electric long range study results as an input.

f. Timing of associated distribution system budgeting processes: Is distribution system budgeting performed on an annual basis or on some other schedule?

Dakota Electric's capital budget is approved annually by the Dakota Electric Board of Directors. A 5 year capital forecast is also provided as part of this annual capital budget. The 5 year forecast is used primarily to identify and plan for years with expected larger than normal capital requirements, so that where possible those year's capital projects can be shifted and the demands on the Dakota Electric labor force can be leveled.

g. Process of developing capital budgets for distribution infrastructure

The development of the capital budget for distribution infrastructure starts each fall, with gathering information for the annual budget. Each of the government agencies are contacted to identify the road rebuild projects which are scheduled for the following year. This information includes many items including, complete road rebuilds, lane additions, bridge replacements, addition of round-a-bouts, addition of turning lanes, traffic control lights, walking trails etc. At this stage of a road project the final engineering design has not been completed, so the impact of the road project on the Dakota Electric distribution system can only be estimated. The actual impact of the road rebuild on the distribution system will not be known until shortly before the electrical modifications are required to be complete.

Also this is when the Dakota Electric personnel who are working with the Cities and residential and commercial developers provide information as to what they have learned about planned and potential new electrical requirements on the system which may impact the capital budget.

A model of the distribution system is then created using the information from employees and the governmental agencies. The model uses the peak feeder loading that is forecasted for the following year. This model is using forecasted non-coincident feeder peak loads to ensure that there is enough feeder capacity to supply all of the Member's non-coincident electrical demands on each of the feeder circuits. The model is utilized to identify equipment that may become overloaded or identify other areas of the system which need to be modified to provide reliable electrical service. Changes to the electrical distribution system are then compiled and costs are estimated for each of the changes. This initial listing of projects are considered required changes as they are required to be completed as the results of new or growing load levels or by projects which are required by governmental agencies, such as road rebuilds.

Another list of potential projects is created from information supplied by Dakota Electric personnel who are responsible for maintenance of equipment and from personnel within the operation area that have identified portions of the system with reliability issues. Also types of equipment with a known history of reliability problems are tracked by the operation department and specific pieces of equipment are identified as candidates for replacement. Added to this list are new technology initiatives. An example of a new technology project would be adding remote monitoring and control to existing equipment to allow for improved operations and reliability.

All of this information is compiled into a master list and the costs are totaled. As with all budgeting, the most difficult part of the budget process is identifying which projects will not be funded in the next year's budget. Dakota Electric does not have any hard and fast budgetary rules for what level of spending is allowed or what projects are cut, but rather looks at the value of the individual projects for our Members and the ability for Dakota Electric to accomplish the project budgeted. In addition to cutting some projects, Dakota Electric delays other projects into future year's budgets, in an attempt to level the capital spending from year to year.

The decision as to what projects are included within the annual capital budget ultimately rests with the representatives of our Member's, the Board of Directors. Each year the details of the capital budget are presented to the Dakota Electric Board and the budget must be approved by the Board before proceeding.

h. Process for developing operating budgets for distribution operating changes or projects

The process for developing the operating budgets is similar to the capital budget. The budget is a bottom up budget. The Dakota Electric staff work together to develop the annual operating budgets and that budget is also presented to the Dakota Electric Board of Directors for their review and approval.

3) Demand and system loading forecast methodologies, including:

a. Granularity of load forecasting: To what extent is the collected system data reflected in load forecasts; e.g., does the utility employ an 8760-hour forecast at the substation level?

Dakota Electric's electrical distribution system is required to reliably supply the Member's electrical kVA demand placed upon the distribution system, at all times. Presently this does not require an 8760 hour forecast and study of the system. The existing nature of the Dakota Electric service territory is that the system's electrical demand peaks during hot summer days, for most of the system. The distribution system capital projects are mostly driven by the need to supply peak demands. It is important to understand that not all circuits peak on the same day or at the same time, so Dakota Electric uses the 5 minute historical SCADA information to identify the individual feeder's peak demands. Another complicating factor is the individual phases of each three-phase circuit, may also peak at different times. Because of this Dakota Electric also identifies the non-coincident peak currents on each of the individual phases for each circuit.

When thinking about the process involved with developing models to study and look at all 8760 hours in a year, the number of possible system operational configurations is enormous. One can just imagine the complexity of accurately forecasting the entire distribution system for each of the hours in a year. You would need to forecast for; each of the substations; each of the circuits and possibly for each of the three electrical phases.

The accuracy of such a forecast will be further complicated by the variable operation of solar, energy storage, load management or other types of Distributed Energy Resources (DER) on the circuit, many of which are not under the control of the utility and their operational profile can only be assumed.

While Dakota Electric does not forecast or study all 8760 hours of the year for the distribution system, Dakota Electric identifies the historical peak loading on each feeder circuit from the substations. Since Dakota Electric is required to design and operate the distribution system to meet the peak demands of the Member's electrical load, the capacity of each feeder circuit must be able to supply the worst case condition. Presently only a few hours of the hours in a year are when a circuit is at or near its' peak load. So the worst case condition for each feeder circuit is fairly easy to identify with the present penetration level of member owned distributed generation.

Using today's engineering analysis tool and with the widespread addition of Member owned distributed generation, it will be extremely complex, if not impossible, to be able to identify the worst case condition(s) for each of the existing 168 feeder circuits. With the tremendous added complexity introduced by intermittent variable distributed generation systems, the ability to forecast and study all of the possible modes of operation will no longer exist. As the transmission systems learned in the 1980 and 1990's the need for a real-time model of the electrical system becomes very apparent. Some distribution utilities have implemented or are implementing an Advanced Distribution Management System (ADMS) to provide a real-time model of the distribution system. Dakota Electric believes that an ADMS coupled with an AMI system will be a basic requirement for the distribution systems in the future.

Dakota Electric has several load forecasts, which are created for different purposes;

- Annually a forecast of the individual feeder circuit's peak demand (kW) is created. This forecast is based upon historical feeder circuit peak demands, potential load growth and planned feeder circuit reconfiguration.

- The Long Range Load Forecast is developed along with Great River Energy to support the resource planning process. This is updated every 2 years. This forecast is primarily an energy, with a single peak summer kW and peak winter kW demand forecasted as a component of the study. This study forecasts load for 20 years into the future.

- As part of the Dakota Electric's Long Range Plan, individual substation peak loads are forecasted and the data from the GRE long range load forecast is used as basis for this individual substation load forecast. The summer and winter peak kW demands are forecasted for each of the substations for each of the studies modeling years. (5, 10 & 20 years) *b. Use of company-wide peak forecasts versus aggregation of substation or other circuit-level peaks: Does the utility use a top-down forecasting approach versus a bottom-up approach, or some combination of these approaches?*

Dakota Electric uses both a top down and a bottom up load forecasting approach. The long range load forecasting, that is completed in conjunction with GRE, is based upon historical system wide coincident demands and is a top-down approach. GRE is responsible to supply Dakota Electric's coincident system demand.

The annual distribution system model is created from individual non-coincident feeder circuit historical demands and is a bottom-up demand forecast. The total of the non-coincident feeder circuit demands is always higher than the Dakota Electric substation coincident demands because the peak feeder demands are non-coincident.

c. Comparison of actual asset loading against past forecasts: Does the utility employ back casting or ex post true-up to assess the accuracy of its forecasting process?

Dakota Electric does not complete a formal process to compare the annual circuit based load forecasts with the resultant actual values. The actual feeder load values are impacted by weather and many other parameters. The distribution system is also a very dynamic system, where circuits are required to be routinely switched to be supplied by other substations and circuits. This switching is triggered by the need to take equipment out for routine maintenance; to provide electrical safety clearance for construction, for both for Dakota Electric's crews and other construction activities; as the result of storm damage etc. Dakota Electric switches load on and off feeder circuits on a routine bases. This routine switching together with the impacts of weather makes historical comparisons more complex and less valuable.

Dakota Electric is required to supply the peak demand of its members at all times. As a result of this the annual forecasted values are maximum numbers and should naturally be greater than the actual load for each of the feeder circuits. The annual forecast is designed to allow adequate electrical supply on an "ultimate peak day". While there is no universal definition of "ultimate peak day", a general assumption is a kW peak demand created by three 95 degrees days in succession. We have also heard other utilities in the Midwest, use three really hot days in a row. This is where experience and engineering judgment is used. Humidity along with cloud cover, wind and other weather factors will affect the "ultimate peak day". Dakota Electric looks back at long term historical data and identifies a general trend for each of the substations and feeders. Through experience, the engineers learn how the substations and feeders are affected by the weather. Some feeders are very weather dependent, while others are supplying commercial load that is affected more by commercial production. Using this historical experience, the more recent year's load, and weather information, a forecasted peak kW is created for each of the substations and feeders. The bottom line is if the distribution system is unable to supply the actual peak demands, we do not meet the needs of our Member's. This is not an acceptable outcome.

d. Minimum load assessments and forecasts: Does the utility utilize minimum load to assess potential impacts of distributed generation on power flows? Are minimum loads measured during peak hours or during night hours?

Dakota Electric does not presently forecast minimum loads on the distribution system. Dakota Electric uses historical minimum load levels as measured by SCADA.

e. Impact on load forecasts of the projected availability of DER: How is utility forecasting impacted by utility assessments on adoption and penetration of DER?

Dakota Electric has a robust load management system. Depending upon how one calculates the numbers; the load management system is able to reduce the system peak demand by 20-25%. This equates to approximately 100-125 MW of electrical demand being shed during the peak on a very hot summer day. The greatest value for Dakota Electric's members is to use this load management system to reduce the billing peak demand from Great River Energy. Dakota Electric's distribution system peak is nearly coincident with most of the GRE system peaks and thus some reduction in Dakota Electric distribution system peak demand is obtained when controlling the peak demand for the GRE system peaks. The Dakota Electric load forecasts are based upon historical peaks which have been controlled through the use of load management, so the forecasts are assuming the full operation of the load management system. All of the distribution studies are assuming that load management is fully operational and that the peak loading on any of the circuits will be reduced by the historical load management operational experience.

The Dakota Electric load management system controls air conditioners, water heaters and other traditional load control systems. In addition to this Dakota Electric has worked with our commercial and industrial members to install member owned generation systems which can completely remove their load from the distribution system. These generation systems are firm capacity, which can be quickly engaged remotely by Dakota Electric, any time of the day or night to start up and reduce the loading on the substation and/or feeder circuit.

The load forecasting with other forms of DER connected to the system has not been tackled by Dakota Electric. The solar installations that we have interconnected are not coincident with the Dakota Electric circuit peak demands, as the Dakota Electric peak demands occur later in the day when the output of the solar systems are nearing their minimum levels. Also since the adoption of the solar systems is dependent upon many factors, such as location, quantity, and size, it is completely up to our individual Member's decision. Thus, for short range planning studies, the engineers are unable to rely on this generation resource developing for a specific area, to cover the demand. As energy storage appears to becoming more affordable, it may provide the ability to shift the solar generation system output so it is coincident with Dakota Electric's peak demand. The capacity issue would be improved but the short term forecasting issue would remain a function of location, quantity and size.

Long range planning is where it would be possible to study non-wire solutions. This would provide the necessary time frame to develop the non-wire solution before the capacity is required.   It is quite possible that non-wire solutions could be incrementally implemented and while not completely eliminating the wires solution, could at least delay the wired options. One of the concerns with delaying the wired solution would be the future permitting of the wired solution. For the most part, Dakota Electric has been able to site the substations and the associated transmission lines in areas before homes and businesses have developed. As people built and purchased their homes, they did so knowing where the wires and substations were located and made a choice to purchase a home near the facilities. <u>It would be significantly more difficult, more expensive and maybe impossible to permit and construct substations and transmission lines into an area after development has occurred.</u>

4) Capital investments and operational projects

a. Assessment criteria and assessment process for feeder and substation reliability, condition of grid assets, and asset loading

After the fact, Dakota Electric analyzes outages to identify where the system can be improved. The field crews report any equipment or configurations which they believe require further investigation or immediate replacement.   The annual system study looks at the loading levels on all of the distribution system components and any equipment that shows up as potentially overloaded is reviewed and replaced if necessary.

b. Alternative analysis protocols for identified needs:

i. Capital versus operating solutions: How does the utility determine whether an assessed need is best met through a capital project or through operational solutions?

The decision to modify the operation, replace or rebuild portions of the system is dependent upon many factors. How has the existing asset performed? How reliable have similar models of this type of asset preformed? Is there an operating change available to reduce or eliminate the risk? Much of the decision making is based upon experience and engineering judgment to determine what the best long term value is for our Member's. In some cases, it is very clear that the equipment is getting old, may soon become obsolete and we need to replace it before it would have a high probability of failure, but in many other cases Dakota Electric has not identified a bright line for the decision to replace or maintain.   It is much like driving an older car and deciding when it is best to sell the car and buy a new one, or fix up the car for one more year?

ii. Near-term versus long-term: Similar to the question above, with the additional factor that some less expensive capital projects may provide a shorter term solution than more comprehensive projects; how does the utility compare these alternatives?

This is an economical decision. Will the less expensive short term solution meet the needs for a long enough period of time for the short term solution to pay for itself vs. the more expensive longer term solution? Another caveat to this decision is; will there be the ability to construct the long term solution in the future? Will there be a change in zoning or land use? Will there be right-of-way available or will that be consumed by others? Will the cost of the longer term solution be significantly increased by not completing the construction in conjunction with existing development? There are times where the permitting issues and the associated risk will not allow a short term lower cost solution to be utilized.

iii. Non-monetized benefits: Apart from reliability and other traditional planning criteria, are other benefits (e.g., economic development, emission reduction) taken into account in considering alternative approaches to resolving system needs?

Within Dakota Electric's service territory the authority having local jurisdiction has established additional rules to help guide potential solutions. A good example of this is many of the Cities have passed ordinances requiring all new electrical installations be installed underground. The Cities have decided to go with the more expensive underground installation to improve the visual appearance.

iv. Non-wires-alternative (NWA) versus traditional solutions: Does the utility consider the potential for DER or other non-wires solution to address an assessed need, to defer or eliminate the need for a traditional capital or operating solution?

Dakota Electric has promoted and implemented non-wire alternatives for many years. Dakota Electric has a robust load management program which has the capability of significantly reducing the system peak demand. This has been done using load management control equipment placed on the member's AC, water heaters and other electrical equipment. Dakota Electric also promotes member owned distributed generation, especially at a scale which is cost effective to control and that can provide firm power, upon request by Dakota Electric.

Dakota Electric is keeping abreast of the new energy storage technologies, used as stand alone or with other distributed generation systems to see where these could be economically and effectively applied.

v. Assessing DER or NWA alternatives: What criteria or metrics are in assessing whether a DER or NWA can meet an identified need?

With Dakota Electric's requirement to supply electricity to our members on demand and at all times, any DER or Non-wires solution utilized instead of another solution cannot degrade the system capabilities or increase the risk for our Members of not having enough distribution system capacity to supply their electrical needs. Utilities often use the term "firm". This is much like the vehicle you own. You have a firm resource available for your use, as needed. If instead you share a vehicle with others, you no longer have a firm resource. In the case of a wired solution that has firm capacity and will be there when it is required to be used. The non-wired solution would need to be evaluated upon the ability to supply the load and/or reduce the load when required and for as long as required.

vi. Scenario analysis: In developing solutions to an assessed need, does the utility consider multiple scenarios, including factors such as load forecasts and DER penetration? If so, what scenarios are standard?

The scenario that Dakota Electric uses for the Annual system studies is assuming the highest "ultimate peak demand" upon the distribution system. Dakota Electric is being counted on to supply the peak demand of our member's entire load. There is not an option of turning off power to a member if we do not plan for enough capacity. Since the Member's do not contract for a specific level of electrical system use (kW) and most of them do not directly pay for the system kW capacity they actually utilize each month, they are not impacted by using more kW than normal for any given month. Thus, Dakota Electric is required to have some spare capacity available on all of the feeders and equipment to provide for this potential situation. Therefore, any scenario that does not provide firm capacity cannot be used for short term planning.

Another problem with scenario planning for the short term, is the time it takes to activate many of the potential scenarios, such as DER, is beyond the short term planning horizon.

On the other hand, scenarios can be leveraged within the longer term planning horizon. Dakota Electric uses DER in the form of load management and member owned generation in the long range plans. This has resulted in saving our members millions of dollars in annual power costs and in some cases delayed a significant dollar amount of distribution infrastructure additions over the past 25 years.

Dakota Electric has found that even with significant rate incentives to accept distributed generation, it was very difficult and takes many years, to get specific members in targeted areas to sign on to the installation of distributed generation systems. Dakota Electric agrees that it is in our Member's best interest to avoid the construction of distribution facilities which may not need to be built if one can find a less costly option using DER or other non-wire alternatives.

c. Metrics for deciding among competing proposals: For any of the applicable categories described above, what specific metrics are used to conduct a comparison of alternative solutions? Are there examples of cost benefit studies or reports the utilities have conducted that can be provided with the responses?

Dakota Electric does not presently have specific metrics for comparison of alternative solutions.

d. Historical distribution system spending: Please provide historical spending over the past five years for capital projects, operating changes or projects, information technology, communications and shared services

Dakota Electrics annual capital spending for projects involving the distribution system is typically between $10 million and $14 million dollars.

5) Locational assessment of DER in long-term planning

Dakota Electric considers that DER includes any form of generation, energy storage or demand management system. Using existing rates, Dakota Electric has worked to encourage specific members to adopt DER. In fact, in the 1990's Dakota Electric formed a subsidiary to help our members implement member owned generation.

a. Describe how the utility uses analytical criteria for assessing potential alternatives to capital and operating improvements during the planning process, if at all, including:

i. Locational DER assessments: Whether locational DER assessments are a part of the planning process or if a DER solution is only considered once a need has arisen

In the 1990's, Dakota Electric saw an opportunity to reduce the system peak using load management. Dakota Electric started a large load management program with the goal of saving money from lower power costs, reducing Great River Energy's need to build that next generation plant and to reduce the amount of distribution facilities required. Dakota Electric has been very successful with this program.

Dakota Electric has utilized different forms of DER to help reduce capital costs. For many years Dakota Electric had a subsidiary that could install and operate on-site generation for our members. Dakota Electric has interruptible rates that encourage our commercial Members to install controllable Distributed Energy Resources which will allow them to curtail or completely remove their energy usage from the Distribution system when requested. While most of the installations were spread throughout the distribution system, a few commercial accounts were contacted with the intent of reducing peak demand on a specific substation or feeder. This targeted load management was used to delay the need to build a new substation or rebuilding an existing feeder. The most significant issue involved with this effort was the long timeframe (years) required to get the DER project(s) approved by the Member through their internal process.

ii. Time sensitivity of the system need: Does the system allow time to develop a potential DER solution? Are there short term traditional projects that can address imminent needs while a longer term DER solution is considered?

With the limited timeframe provided by new loads and other developments, short term planning does not allow enough time to implement non-wired solutions. Longer term there is more opportunity to affect the nature of the new loads which are added to the system and encourage the modification of existing loads. Dakota Electric works with new home builders and new home owners to utilize energy efficient appliances and construction techniques. Dakota Electric provides many options for our Members to help control their peak electrical demand on the system and provides incentives to do so. Over time the total aggregation of each house or business has added up to a useful amount of demand reduction and controllable loads.

b. Where DER or non-wires alternatives are on par with traditional projects, based on the analytic criteria described above, is there a mapping of those geographic areas in which DER could replace or defer specific capital or operating projects?

Dakota Electric does not have a map of end-use loads to target for more load management. Intermittent resources will not display required distribution assets as discussed earlier.

6) Security

a. What controls and processes are used to secure consumer and system data, IT/communication systems, and physical infrastructure?

Dakota Electric uses several layers of physical and cyber-security to protect data and physical infrastructure. Protection of our Member's data is a high priority for Dakota Electric and our Board is very supportive of our efforts with cyber-security and physical infrastructure security and reliability. Dakota Electric believes this is not the proper forum in which to discuss security details. Dakota Electric would be open to further discussion of physical and cyber security in the proper venue.

b. What protocols and cooperative arrangements with NERC, NIST or other entities are used to identify threats and available defense measures?

Dakota Electric interacts with other utilities, many local and national organizations, business partners, as well as local, state and federal government agencies to share information about potential threats, risks, vulnerabilities and best practices for cyber and physical security countermeasures. Dakota Electric is also a partner in several mutual aid agreements in which the participants will assist each other in the event that one or more partners experience a cyber-security incident, attack, or breach. Our organization also conducts periodic audits and assessments of its cyber security posture using independent parties.

Section B
What is the status of each utility's current distribution system plans?

Please describe information on any existing distribution system plan, including (where applicable):

1) The date initiated, completed, and the planning timeframe used: For each planning component, the number of years to which it is applicable should be specified

Dakota Electric's annual planning studies are completed each fall as part of our annual budget process. The Long Range Load Forecast was last completed in 2016 and is scheduled to be updated in 2018 in conjunction with Great River Energy. The Long Range Distribution Planning process was last completed in 2006 and it is more than 10 years since the last formal long range planning process. As part of the 2017 budget, Dakota Electric is planning on starting the process to complete a new Long Range Distribution Plan. These long range studies are expensive and require a significant investment in engineering labor. We are presently planning on starting the long range planning process later in 2017 and expect that process to take all of 2018 to complete.

2) Scenarios: the range of any scenarios that were considered should be identified, e.g. high/low load forecast, high/low DER penetration

The annual and long range planning studies are aimed at ensuring there is sufficient capacity available to meet the electrical needs of our members. So the studies are done looking at the peak expected loading levels on each of our substations and associated feeders. The studies assume that the existing load management system is operational and available. The load management system includes both control of member's individual loads, such as AC and water heaters but also includes coordinated member curtailment and member owned diesel generation, where the generation units are designed to remove all of the member's electrical demands from the distribution system and operate as an electrical island, when requested. This reduces the peak demand expected and planned for on each of the substations and feeders.

Dakota Electric's present penetration of intermitted generation, such as solar and wind has not yet reached a level where the operation of the distribution system is impacted. As more DER which is not under the control of Dakota Electric is proposed and installed, Dakota Electric will need to complete new forms of operation planning studies to look at how the system protection and system voltages could be affected by the operation of the new member owned generation systems. These will be significantly more complex and are expected to involve a significant number of scenarios and multiple operating conditions.

3) System constraints and needs:

a. At a high level, what system constraints and needs are anticipated to develop or occur within the planning period? (Further detail is requested below)

Dakota Electric has continued to follow the reports from other utilities with higher amounts of intermittent DG interconnection. As with anything new, there is a concern with the possible issues that could develop. We have heard that many of these initial concerns are not as significant of a problem, but as part of the learning process there are new constraints which are being identified.

There are two main constraints which Dakota Electric has identified as part of supporting DG integration. The first is the ability to operate the distribution system during periods when the distribution system is not in the normal configuration. The distribution system is seldom in the normal configuration. This is due to construction activities, outages of equipment for safety clearance, outages of equipment for maintenance of the equipment and restoration during storms.

The other constraint is with load that is masked by the operation of the DG systems. Dakota Electric has some experience with this issue, as our existing load management system is able to shed 20-25% of our peak demand. So the question which the engineers are asking is, what the peak demand would be if the load management system failed and was not able to interrupt the load on a peak day. We have dealt with this through redundancy on the load management system and also through diversity of the load control systems, so not every load is controlled by one system. With other forms of DG, the member's actual total electrical demand can be masked by the operation of the DG. At present, the operation of the existing intermittent generation interconnected to the Dakota Electric system is not reducing the peak electrical demand on the substations and circuits. The thought is, using new technology, including energy storage the DG could be designed to reduce the normal peak loading on the system. How reliable is this reduction of the peak demand? The main concern is during restoration, after an outage event, where the DG is unable to supply the electrical load during the first few minutes of the circuit restoration. At that moment, all of the masked load will be applied to the distribution circuit and each of the distribution system components will need to be sized to meet that short term demand.

b. How have these constraints and needs been prioritized based on assessment criteria, time sensitivity, budget impact, or other criteria?

Dakota Electric has not identified any of these constraints which are imminent and need modification to the distribution system or the utility planning process. These constraints need to be discussed and resolved through standards and procedures. To deal with the load which could be masked by the DG systems, Dakota Electric is presently installing a production meter so the total load which could be applied to the distribution system is known and capacity can be reserved on the distribution system.

4) The current and forecasted extent of DER deployment by type, size, and geographic dispersion

Dakota Electric does not have a forecast for solar, wind and energy storage integration levels for the Dakota Electric system.

5) Currently planned distribution capital projects and operating changes, including:

a. Capital and operating budgets over the applicable planning period, and to the extent possible, breakdowns of categories of expenses and budgets

Dakota Electric's annual capital spending for projects involving the distribution system is typically between $10 million and $14 million dollars. This includes all capital spending for the electrical distribution system.

b. Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change

Dakota Electric's annual budget has remained fairly consistent over the past 10 years. The most significant changes in the capital budget have been due to level of new growth and the costs associated with road rebuild projects.

c. Any analysis of alternatives, mitigation, or deferrals of capital or operating projects that were conducted

Dakota Electric does not have any formal analysis of mitigation, deferrals of capital or operating projects due to the installation of DER. Instead Dakota Electric has informally used targeted member owned generation installations to defer capital spending.

Dakota Electric has worked with specific commercial and industrial members to install member owned generation systems which are able to completely remove their load from the distribution system. These generation systems are firm capacity, which can be quickly engaged remotely by Dakota Electric, any time of the day or night to start up and reduce the loading on the substation and/or feeder circuit. Since this is a firm generation resource, that is predictable and controllable, Dakota Electric has been able to use this to defer substation capacity rebuild projects and to be available to provide contingency support for circuit during construction projects.

Dakota Electric continues to interact with Cooperatives across the country and with EPRI to learn about better ways to design and utilize new technology for the distribution system. The sharing of good and bad experiences with the integration and use of all forms of DER, is where utilities can save costs and more quickly identify what works and what does not work.

d. Identification of any future capital or operating projects that could reasonably be considered for substitution, mitigation, or deferral using DER alternatives

Dakota Electric does not presently have any distribution projects identified which we believe can be mitigated or deferred using DER alternatives.

e. Identification of any non-monetized benefits of planned projects

Dakota Electric is not sure what this question is asking, especially in reference to which projects.

Dakota Electric routinely replaces existing overhead distribution lines with underground facilities and this could be considered a non-monetized benefit, although in most cases someone is paying for the added cost of placing the distribution facilities underground. Dakota Electric also completes many projects to improve the reliability of the system for which Dakota Electric does not receive any financial benefits, but which are completed to benefit our members.

f. Identification of any projects that will enhance the company's future ability to integrate DER into system operations

Dakota Electric is in the process of reviewing and evaluating an AMI system, which includes electronic meters with two-way communication. We believe that this system would eliminate the cost of replacing the existing meters, each time a solar or wind system is installed at a member's premise. This new AMI system would also allow Dakota Electric to remotely modify the configuration and programming within the meter to facilitate changes in the tariffs. The overall proposed project includes AMI metering, meter data management (MDM) and a replacement and upgrade of our existing load management system. Dakota Electric is referring to this overall project as the Advanced Grid Infrastructure project or (AGi).

The AMI system, coupled with a meter data management system (MDM), is expected to provide a foundation, upon which future applications can be installed. For example an Advanced Distribution Management System (ADMS) is an operational and engineering program which provides a model of the distribution system. The ADMS provides a near-real time analysis of the distribution system and supports various operational and engineering studies. With the dynamic nature of the new member owned DER systems, Dakota Electric believes that systems such as an ADMS will be required to allow safe and reliable operation of the distribution system in the near future.

The refurbishment of the existing load management system is planned to use the AMI communication network for 2-way communication to the load control receivers. This will enhance the ability to monitor the operation of the receivers and support new methods of load management and new opportunities for demand management.

g. Identification of any other projects, or investments, not specifically identified pursuant to (f) above, that support grid modernization as defined in the <u>Staff Report on Grid Modernization (March 2016)</u>

Dakota Electric has no additional plans other than the AGi project which consists of the AMI, MDM and upgrading of our existing Load Management system.