MINNESOTA
PUBLIC UTILITIES COMMISSION

# Staff Briefing Papers

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| Meeting Date | August 13, 2020 | Agenda Item 2* |
| Company | Dakota Electric Association | |
| Docket No. | **E111/M-19-674** | |
| | **In the Matter of Dakota Electric Association's 2019 Integrated Distribution System Plan** | |
| Issues | 1. What action should the Commission take with Dakota Electric Association's 2019 Integrated Distribution System Plan (IDP)?<br>2. Should the Commission adjust any of the IDP filing requirements for Dakota Electric Association's next IDP? | |
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| ✓ **Relevant Documents** | **Date** |
|---|---|
| Dakota Electric Association, 2019 Integrated Distribution Plan | October 31, 2019 |
| Rakon Energy, Public Comment (Doc. ID No. 20201-159656-01) | January 27, 2020 |
| Department of Commerce - Division of Energy Resources, Initial Comments | January 29, 2020 |
| Clean Energy Economy Minnesota, Initial Comments | January 29, 2020 |
| Dakota Electric Association, Initial Comments | January 29, 2020 |
| Department of Commerce - Division of Energy Resources, Reply Comments | February 19, 2020 |
| Dakota Electric Association, Reply Comments | February 19, 2020 |

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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## I. Statement of the Issues

What action should the Commission take with Dakota Electric Association's 2019 Integrated Distribution System Plan (IDP)?

Should the Commission adjust any of the IDP filing requirements for Dakota Electric Association's next IDP?

## II. Background

On October 31, 2019, Dakota Electric Association (Dakota Electric or Association) the Association's inaugural Integrated Distribution Plan (IDP) in response to filing requirements established by the Commission's February 20, 2019 *Order Adopting Integrated Distribution Plan Filing Requirements* in Docket No. E111/CI-18-255.

The purpose of the Commission's IDP filing requirements is to facilitate a utility's IDP filing that will meet the following planning objectives: [1]

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- 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;

[1] MN PUC, ORDER ADOPTING INTEGRATED DISTRIBUTION PLAN FILING REQUIREMENTS at 2 (February 20, 2019), Docket No. E111/CI-18-255.

- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

On December 4, 2019, the Commission issued a Notice of Comment Period asking parties to answer four questions as they reviewed Dakota Electric Association's 2019 IDP:

1. Should the Commission accept or reject Dakota Electric Association's Integrated Distribution Plan (IDP)?
2. Does the IDP filed by Dakota Electric Association achieve the planning objectives outlined in the filing requirements approved in the Commission's February 20, 2019 Order?
3. What IDP filing requirements provide the most value to the process and why? Are there filing requirements that are not informative and/or should be deleted or modified, and why?
4. Are there other issues or concerns related to this matter?

On January 27, 2020, Rakon Energy filed public comments.[2]

On January 29, 2020, the Department of Commerce-Division of Energy Resources (Department), Clean Energy Economy Minnesota (CEEM), and Dakota Electric submitted initial comments.

On February 19, 2020, the Department and Dakota Electric filed reply comments.

## III. Summary of the Issues

Parties agree the Commission should accept Dakota Electric's 2019 Integrated Resource Plan and recognize acceptance is not a determination of prudence of any proposed system modifications or investments (**Decision Option 1**).

The Department makes two recommended edits to Dakota Electric's future IDP filing requirements: 1) explain how the IDP achieves the planning objectives (**Decision Option 2**); and 2) more detail about the cost benefit analysis (**Decision Option 3**.) Lastly, the Department identifies a typo in utilities' filing requirements and suggests removing the term "annual" in the second paragraph under Planning Objectives. (**Decision Option 4**.)

Dakota Electric Association suggests rather than amend filing requirements as suggested by the Department (**Decision Options 2 and 3**) that the Commission, Dakota Electric and stakeholders in a workgroup should review and discuss filing requirements for efficiency and shared understanding (**Decision Option 5**). Further, Dakota Electric requests the daytime minimum load data provided in 3.B.1 be adjusted from feeder to substation (**Decision Option 6**).

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[2] There are several public comment filings from the same entity, Rakon Energy, and some items were duplicates. Document ID No. **20201-159656-01** includes all comments submitted by Rakon Energy.

Rakon Energy filed public comments focused on the cost estimate for energy storage systems and suggested project opportunities; as well as, an Emerging Technology Coordinating Council for Minnesota utilities. Clean Energy Economy Minnesota highlight several areas for improvement in the next IDP; including the cost-benefit analysis and DER scenarios forecast.

These briefing papers provide a staff summary of Dakota Electric's 2019 IDP (**Section IV**) and the Party Comments (**Section V**) and close with Staff Analysis (**Section VI**) and the Decision Options (**Section VII**.)

## IV. Summary of Dakota Electric's 2019 IDP

Dakota Electric held one stakeholder workshop to solicit public input and discussion on their 10-year distribution investment plan and completed additional outreach to the residential and commercial members regarding its capital spending and research into the use of non-wires solutions (NWS). Dakota Electric engaged STAR Energy Services LLC and Center for Energy and Environment in the stakeholder process, a request for information from DER providers on non-wires solutions, and in writing the 2019 IDP.

### 1. Baseline Data (System, Financial and Distributed Energy Resources)

<u>System</u>

Dakota Electric Association is a not-for-profit electric distribution cooperative with over 108,000 members (> 120,000 meters) in a 500 square mile service territory within Dakota, Scott, and Goodhue counties. Dakota Electric is the second largest electric distribution cooperative in Minnesota and ranked among the 25 largest in the nation. Further, Dakota Electric highlights ranking as one of the most reliable electric utilities in the United States. Dakota Electric's peak demand is between 450-500 MW and occurs in the summer – primarily due to air conditioning. Dakota Electric avoids sharing coincident peak demand with GRE through coordinated operation of a robust load management or demand response program (20-25% of peak demand) – saving members millions of dollars annually in wholesale power costs.[3]

Dakota Electric uses Milsoft Windmill software for modeling and maintains real-time and normal system connectivity and equipment information within GIS; including an outage management system (OMS). Data can be extracted from the GIS and used to create study models the modeling software. Dakota Electric considers Advanced Distribution Management Software (ADMS) a need in the future with higher penetrations of DER but is focused on implementing the Advanced Grid Infrastructure (AGi) project currently; including advanced metering infrastructure and associated software.

[3] Dakota Electric Association, IDP at 5-7, 26, 28 (October 31, 2019) in Docket No. E-111/M-19-674.

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, but is adding SCADA to some of the downline regulators and key remote switches on the feeders.[4] All substations are monitored in near real-time with some data stored every minute; whereas, only 10% of feeders have some type of SCADA and are not monitored in real-time. Dakota Electric has at least 125 member-owned DER with SCADA monitoring and control as part of the Commercial and Industrial Interruptible rate offering with electrical usage being recorded every 15-minutes within the meter and uploaded periodically to Dakota Electric. With implementation of Dakota Electric's AGi, members' electrical usage and voltage data will be recorded every 15 minutes and sent to Dakota Electric every four hours.[5]

Dakota Electric has over 4,000 miles of distribution lines – a majority of which are underground (2,961 mi) compared to overhead (1,188 mi.)[6] Dakota Electric estimates a 12-month average loss percentage of 2.46% (using meter reads of energy sales and "own use" energy subtracted from monthly energy purchases from GRE.) Dakota Electric highlights a 50% reduction in line losses over the past 30 years through equipment efficiency improvements, changes in how the system voltage is managed during light loading periods, improved control systems for capacitors and replacement of wires and cables with larger capacity.[7]

Distributed Energy Resources

Staff summarizes the reporting in Dakota Electric's IDP on both supply and demand-side DER[8]:

[4] Dakota Electric Association, IDP at 10 and 18 (October 31, 2019) in Docket No. E-111/M-19-674.
[5] Dakota Electric Association, IDP at 19-20 (October 31, 2019) in Docket No. E-111/M-19-674.
[6] Dakota Electric Association, IDP at 31 (October 31, 2019) in Docket No. E-111/M-19-674.
[7] Dakota Electric Association, IDP at 25-27 (October 31, 2019) in Docket No. E-111/M-19-674.
[8] Dakota Electric Association, IDP at 33-37 (October 31, 2019) in Docket No. E-111/M-19-674.

| DER | Quantity | Megawatts (MW) | Summer Load Reduction (MW) | Winter Load Reduction (MW) |
|---|---|---|---|---|
| Solar | 216 | 6.1 | | |
| Storage | 0 | 0 | | |
| Wind | 12 | .2 | | |
| Gas Engine | 127 | 165[9] | | |
| Combined Heat and Power | 0 | 0 | | |
| Electric Vehicles (on EV rates) | 323 | N/A | | |
| Energy Efficiency | N/A | 26,284 MWh/yr | | |
| Air Conditioning | 51,162 | 50 | 15-25 | N/A |
| Heat Pumps | 2,742 | 10 | 3-5 | 2-8 |
| Heat Devices | 3,295 | 29 | N/A | 5-10 |
| Irrigation | 375 | 24 | 0-15 | N/A |
| Water Heat | 7,296 | 33 | 4-8 | 5-10 |
| Miscellaneous | 752 | 5 | 1 | 1 |
| C&I Interruptible Generation | 127 | 86 | 50-65 | 30-50 |
| Curtailment | 20 | 9 | 2-5 | 2-5 |

Dakota Electric's IDP includes a DER Summary Report which includes by substation and feeder the number and capacity of various load control, demand management, solar, and wind.[10] In addition, Dakota Electric assisted in the creation of several members' campus micro-grids which 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.[11]

Financial

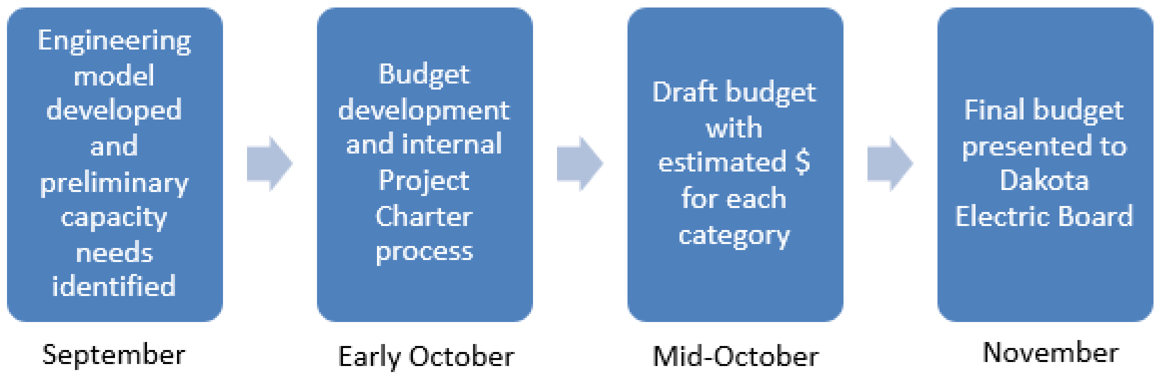
Dakota Electric outlines the Cooperative's annual construction capital budget process. Staff summarizes the timeline:[12]

[9] This is the prime engine rating for customer generation associated with the C&I Interruptible Generation program. The difference in MW is because the C&I Interruptible Generation MWs are based on the load reduction at the site.

[10] Dakota Electric Association, IDP at 130-137 (Appendix A) (October 31, 2019) in Docket No. E-111/M-19-674.

[11] Dakota Electric Association, IDP at 8-10 (October 31, 2019) in Docket No. E-111/M-19-674.

[12] Dakota Electric Association, IDP at 11-13 (October 31, 2019) in Docket No. E-111/M-19-674.




Dakota Electric describes the dynamic nature of distribution system capital budgets; including coordination with possible road construction and new or changing customer needs. Dakota Electric estimates 40-75% of an annual capital budget is in response to new electric supply or governmental projects. Other capital project budgets are forecasted based on historical data and reactionary to member needs or equipment failure; such projects include miscellaneous distribution equipment, service rebuilds, and pole replacements. Additional projects which may be proposed include new residential and commercial services, underground cable replacement, transformer replacement and substations. Substations require a few years advance lead time for permitting and construction. As this budget is being developed, an internal Project Charter process considers larger initiatives which may impact the capital construction budget; such as the AGi project. Dakota Electric notes:[13]

> 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.

In addition to the annual budget process, Dakota Electric completes a 5-year capital construction forecast to help identify peaks and valleys in future capital spending to utilize limited resources and reduce budget swings. Forecasts include substation planning (2-3 year lead time), annual estimate for reliability and age-related replacements, city and county road rebuild projects, and technology projects.

Staff offers the chart below summarizing Dakota Electric's engineering estimate of the 5-year historic capital spending and forecasted 5-year future spending.[14]

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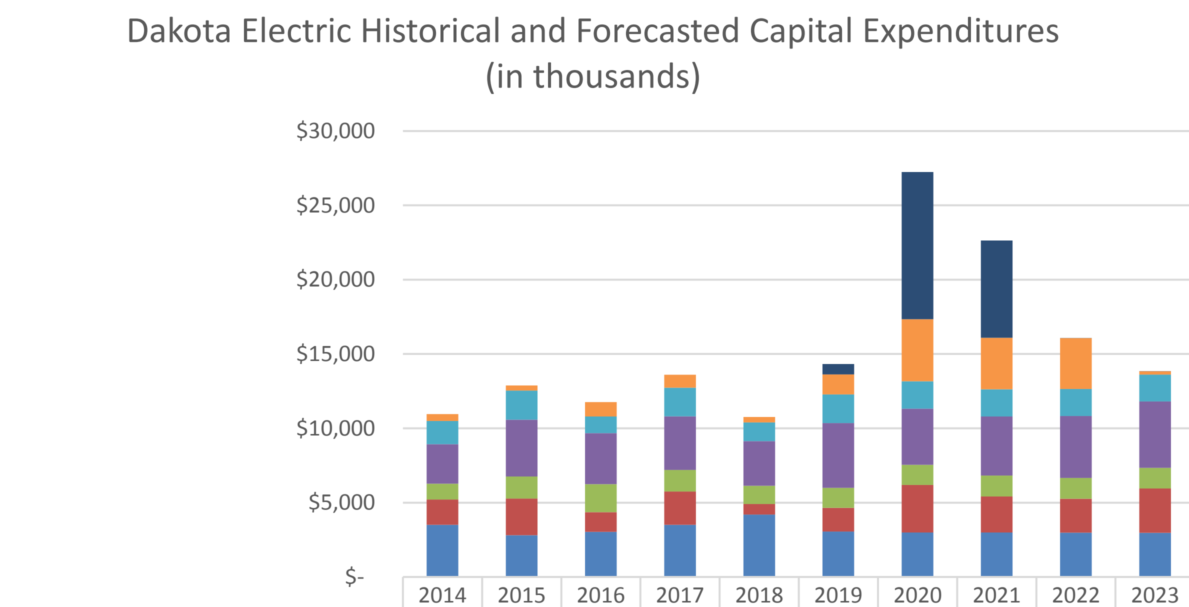
[13] Dakota Electric Association, IDP at 14 (October 31, 2019) in Docket No. E-111/M-19-674

[14] Dakota Electric Association, IDP at 39, 41 (October 31, 2019) in Docket No. E-111/M-19-674. Staff's chart does not include Contribution in Aid of Construction. Metering in future forecast is related to roll out of AMI meters for the Advanced Grid Initiative (AGi). Dakota Electric notes these numbers are engineering estimates because the accounting for capital expenditures does not use these categories and tracks what was constructed rather than why it was constructed. Dakota Electric established a $50,000 threshold for a project to be included in the future forecasted budget. Projects for connecting new, larger commercial services in 2019 were also not included.




| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|
| Metering | $- | $- | $- | $- | $- | $704 | $9,901 | $6,539 | $1 | $1 |
| Grid Modernization (Advanced Technologies) | $465 | $343 | $973 | $880 | $361 | $1,342 | $4,178 | $3,471 | $3,423 | $221 |
| System Project (Driven by Mandate) | $1,568 | $1,956 | $1,121 | $1,924 | $1,263 | $1,933 | $1,837 | $1,829 | $1,819 | $1,811 |
| New Members | $2,652 | $3,826 | $3,429 | $3,603 | $3,006 | $4,356 | $3,779 | $3,973 | $4,170 | $4,468 |
| System Expansion (Due to Reliability) | $1,065 | $1,488 | $1,884 | $1,449 | $1,220 | $1,346 | $1,357 | $1,403 | $1,395 | $1,390 |
| System Expansion (Due to Capacity) | $1,699 | $2,457 | $1,330 | $2,247 | $716 | $1,592 | $3,194 | $2,424 | $2,289 | $2,982 |
| Age Related Replacement | $3,513 | $2,814 | $3,032 | $3,506 | $4,195 | $3,056 | $2,997 | $2,995 | $2,979 | $2,966 |

Dakota Electric did not provide operating and maintenance expenditure data and notes capital construction budgets do not include expense spending for maintenance and operational items such as tree trimming, underground locating services, power quality investigation or outage restoration.[15]

### 2. Long-Term Distribution System Modernization and Infrastructure Investment Plans

Dakota Electric projects moderate load growth in the Cooperative's long-range load forecast (LRLF) based on each energy usage (or customer) class. The IDP includes a high-level discussion of the assumptions used for the Residential and Small and Large Commercial forecasts.[16]

The primary focus for distribution system modernization is Dakota Electric's Advanced Grid Initiative (AGi) – the single largest project the Cooperative has ever undertaken – which includes:[17]

- Installation of a meshed Radio Frequency (RF) communication network;

[15] Dakota Electric Association, IDP at 11 (October 31, 2019) in Docket No. E-111/M-19-674.
[16] Dakota Electric Association, IDP at 66-68 (October 31, 2019) in Docket No. E-111/M-19-674.
[17] Dakota Electric Association, IDP at 69-70 (October 31, 2019) in Docket No. E-111/M-19-674.

- Replacing all existing meters with digital two-way meters (Advanced Metering Infrastructure (AMI));
- Addition of a Meter Data Management System (MDMS) to store metering data, including alarms and events from the edge devices; and
- Replacement of all existing load management receivers (50,000+) at member homes and businesses.

Dakota Electric spends most of the Long-Term Distribution System Modernization section of the IDP discussing the AGi.[18] In this summary, AGi includes a member portal with energy usage data and the ability to download and share the data with third parties, if the member chooses. Dakota Electric also highlights a fully integrated GIS system with asset management, operational management system and close integration with work management and accounting was installed in 2009 creating a data hub supporting near-real time network connectivity model and graphic representation of the electric distribution system. AGi is designed to further integrate islands of data within the utility.

Dakota Electric learned through review of other utilities' implementation that many of the benefits of AMI and MDMS were not being achieved due to limited integration between the new systems and the utility's existing systems. The AGi requires integration of three systems from three different companies: AMI (Itron), MDM (Harris), and Demand Response (Yukon – Load Management), so Dakota Electric set up the new and existing systems for integration testing prior to installation of equipment. This is known as the Conformance Acceptance Testing phase. The next phase, Site Acceptance Testing, has a key milestone of delivery of the promised functionality for the system. If this milestone is not met, Dakota Electric has the right to forego advancing to the final stage which is replacement of all the meters and many of the load control receivers resulting in an RF mesh communication system with over 150,000 edge devices. This final stage is referred to as Performance Acceptance Testing and was anticipated for Summer 2020 into 2021. Through 2023, Dakota Electric plans to receive the benefits of the AGi, use meter data to troubleshoot performance, and continue replacement of edge devices.[19]

### 3. Preliminary Hosting Capacity Data and DER Interconnection

Dakota Electric provided a spreadsheet of annual minimum load levels and annual daytime minimum load levels for the 165 feeders on the Cooperative's distribution system; as well as, the minimum and maximum loading level for each of the substations.[20] The Cooperative noted overall substation minimum loading is one of the key determinants for whether a transmission study is required in DER interconnection review. The Cooperative also highlighted the importance of coincidence for determining the substation minimum value, noting the sum of each feeder's minimum value is not the equivalent because feeder minimums do not all occur at the same time (non-coincident). Dakota Electric cautioned switching loads from feeders for emergency, maintenance or construction and active load control could impact the minimum

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[18] Dakota Electric Association, IDP at 70-78 (October 31, 2019) in Docket No. E-111/M-19-674. For more on AGi, see Docket No. E-111/M-17-821 *In the Matter of Dakota Electric Association's Petition to Implement Tracker Recovery for Advanced Grid Infrastructure Investments*.
[19] Dakota Electric Association, IDP at 70-73 (October 31, 2019) in Docket No. E-111/M-19-674.
[20] Dakota Electric Association, IDP, App. B – Substation and Feeder Minimum Loading Levels (October 31, 2019).

values reported. The effort to clean data to compile the spreadsheet to two people over a three month period. The Cooperative suggests future IDPs require minimum load levels for the 31 substations and not the feeders to reduce manual effort and produce the most useful result (**Decision Option 6**.)[21]

Dakota Electric reported the following interconnection data for 2018:

| | # of Interconnections | Installed Capacity (MW) |
|---|---|---|
| **Solar** | 39 | 2.4 |
| **Solar/Storage** | 0 | 0 |
| **Storage** | 0 | 0 |
| **Wind** | 0 | 0 |
| **Gas Engine** | 1 | .5 |
| **Combined Heat & Power (CHP)** | 0 | 0 |

In 2018, the Cooperative estimates $57,437 in costs incurred by the utility to support the interconnection process, not including metering which is accounted elsewhere. Dakota Electric collected $4,700 in interconnection application fees. As of October 2019, the Cooperative had 39 DER interconnection applications in queue (37 solar, 1 solar/storage, and 1 hydro.)[22]

### 4. DER Scenario Analysis

Dakota Electric took a different approach in the DER Scenario Analysis which resembled a hosting capacity analysis. Rather than producing a medium and high case forecast scenario, the Cooperative studied at what solar DER penetration level would the distribution system require mitigation to accommodate additional DER. The modeling analysis applied two scenarios to the existing system base model (2018 summer peak): 1) new solar additions were 10 kW residential (dispersed and concentrated); and 2) new solar was 1 MW installations not sized to load. This analysis found reverse power flow and high voltage as the two main limiting factors. Reverse power flow occurred when the DER capacity exceeded the loading on a circuit and could result in transmission impacts. High voltage occurred when DER capacity was in a concentrated area on the same phase of a tap line and when the DER was further from the substation. The Cooperative also identified insights; such as, substation voltage settings to mitigate impacts, fixed vs. adaptive voltage regulation impacts on DER depending on the proximity to the substation and distribution system losses. Dakota Electric concluded 100 MW of DER capacity could be accommodated without significant distribution upgrades if sized to existing load at the point of connection. If the DER was evenly distributed, up to 200 MW of DER could be accommodated. However, if DER is not sized to load or is concentrated significant distribution upgrades would be required at lower DER penetrations.[23]

[21] Dakota Electric Association, IDP at 47-51 (October 31, 2019) in Docket No. E-111/M-19-674.
[22] Dakota Electric Association, IDP at 34-37 (October 31, 2019) in Docket No. E-111/M-19-674.
[23] Dakota Electric Association, IDP at 52-65 (October 31, 2019) in Docket No. E-111/M-19-674.

### 5. Non-Wires (Non-Traditional) Alternatives Analysis

Four projects qualified for the $2 million threshold for non-wires alternatives (NWA) analysis; however, only two were evaluated with a high-level NWA analysis. Dakota Electric considers AGi a non-wires solution that will provide greater information about the distribution system and support more efficient construction and operations. The second project not analyzed was a conversion and rebuild of a substation shared with Great River Energy which the Cooperative found not suitable for NWA due to underground transmission line failures and advanced age of the substation.[24] The two projects evaluated were: 1) adding capacity at an existing substation with an additional transformer and switchgear; and 2) siting and constructing a new substation.

Dakota Electric outlined a list of requirements for a substation project. Dakota Electric's evaluation found potential NWAs uneconomical because land costs for new solar or storage sufficient to meet the need, energy storage system (ESS) costs, and not all equipment could be deferred.[25] Dakota Electric considered three NWA options for deferring the new substation: 1) storage, 2) solar, and 3) demand-side management (DSM). In this analysis, Dakota Electric factored in more than installed costs; including solar production benefits at full on-peak value and ESS benefits for reducing 80% of peak demand charges and arbitrage from off peak charging and on peak discharge compared to the new substation. In Dakota Electric's analysis, DSM was the lowest cost NWA, but still more expensive than building the new substation ($5.5 million versus $3.9 million.) Dakota Electric concludes the NWA analyzed are more costly and have a much greater risk of not being able to meet the energy demands of the members' load.[26]

Dakota Electric issued an RFI asking vendors to suggest NWA to specific traditional distribution planning problems. Dakota Electric learned, rather than a cost threshold, the type and capacity size of problem was more significant in determining NWA viability. Five vendors responded to four problem statements: 1) limited main circuit capacity; 2) serving new load; 3) contingency support; and 4) mobile generation source for contingencies. Dakota Electric summarized the problem, traditional solution, and assumptions used; as well as, compares the NWA responses on installation timeframe, operations and maintenance, performance, and cost over a 25-year timeframe. NWA showed the potential to compete on a cost-benefit basis both for limited main circuit capacity and to serve new load when distribution infrastructure (circuits and substation) have limited capacity.[27]

Dakota Electric categorizes the Cooperative's existing load management and solar as existing NWA on their distribution grid. However, Dakota Electric identifies several reliability concerns to consider when considering a NWA to a traditional wires solution. The Cooperative sees AGi

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[24] Dakota Electric Association, IDP at 80-81 (October 31, 2019) in Docket No. E-111/M-19-674.

[25] Dakota Electric Association, IDP at 83-84 (October 31, 2019) in Docket No. E-111/M-19-674.

[26] Dakota Electric Association, IDP at 85-97 (October 31, 2019) in Docket No. E-111/M-19-674.

[27] Dakota Electric Association, IDP at 99-121 (October 31, 2019) in Docket No. E-111/M-19-674. Decommissioning was also discussed.

as a foundation for future functionality to support further DER integration. Dakota Electric concluded the NWA analysis with several lessons learned:[28]

- Larger capacity need increase cost competitiveness of NWA with a traditional solution;
- Modular expansion of ESS And PV offer benefits if capacity needs increase over the duration of the NWA's expected useful life;
- Expected up-time and useful life of NWA still trail traditional solutions which risks reliability and costs;
- Step change needs in available capacity for an area that is underserved for short durations seem the most compatible with a NWA rather than a cost threshold; and
- Demand-side management is the lowest cost NWA.

Dakota Electric's IDP closes with a report summary and a list of suggestions for future IDP reports:

- Encourages a process and review of the information requests so that the data included in future IDPs is efficiently gathered and presented;
- Document how the information being requested will be utilized, so that adjustments to data provided help support these use cases;
- Create a working group of stakeholders, including representatives from each of the regulated utilities, to review and discuss draft IDP filing requirements for the next round of IDP reports (**Decision Option 5**);

In addition, Dakota Electric summarizes three portions of the IDP filing requirements that were the most difficult or time consuming to provide: 1) cost categories for DER interconnection and integration; 2) listing planned distribution projects for the next five years; 3) minimum load data. On the latter, Dakota Electric reiterates the request that for future IDPs that substation minimum load data be reported instead of the individual feeder minimum load levels (**Decision Option 6**).

## V. Parties' Comments

### a. Department of Commerce

The Department recommends the Commission accept Dakota Electric's 2019 IDP with the recognition that approval is not pre-approval or an advanced determination of prudence for any proposals contained within the IDP (**Decision Option 1)**.[29]

The Department's analysis was focused to ensure the IDP met the requirements as set out in the Commission's Order and offered suggestions for future improvements to IDP reports as well as potential modifications to the IDP filing requirements.[30] The Department recognized the Association's IDP as compliant to the Commission's *Order Adopting Integrated Distribution Plan*

[28] Dakota Electric Association, IDP at 123-125 (October 31, 2019) in Docket No. E-111/M-19-674.
[29] Department of Commerce, Reply Comments at 3,6 (February 19, 2020).
[30] Department of Commerce, Initial Comments at 2 (January 29, 2020).

*Filing Requirements*[31] and viewed "DEA's first IDP Report as the beginning of a dialogue between the utility, regulators, and stakeholders interested in the orderly, cost-efficient, and synergistic evolution of the distribution system."[32]

Initially, the Department requested additional information from the Association before it would recommend Commission acceptance of the Report.[33] The information and view into the Association's distribution planning is helpful, though "given that that the IDP process is designed to be iterative and will necessarily evolve over time, the question of whether the planning objectives were achieved by the IDP Report is somewhat premature."[34]

The Department further reviewed the IDP against each planning objective from the February 20 Order below:

> 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 the utility's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

A table on page 4 of the Department's initial comments lists where Dakota Electric discussed each topic of the first planning objective in their IDP. "The topics of maintaining and enhancing security and resiliency of the electricity grid were minimally referenced or not referenced at all in DEA's IDP. The other planning topics—safety, reliability, and fair and reasonable costs—were discussed, however."[35] Since there was a lack of information, the Department requested the Association provide additional details on how it maintains and enhances security and resilience of the electric grid in their reply comments.[36] Dakota Electric responded in reply that as a distribution-only cooperative there is a dependence upon others (Great River Energy and Xcel Energy) to provide security and resilience for generation and the transmission grid. Dakota Electric also outlined several ways the Cooperative addresses security and resilience of the

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[31] February 20, 2019 Order from Docket No. E017/CI-18-253, E015/M-18-254, and E111/CI-18-255.
[32] Department of Commerce, Initial Comments at 2 (January 29, 2020).
[33] Department of Commerce, Initial Comments at 3 (January 29, 2020).
[34] Department of Commerce, Initial Comments at 3 (January 29, 2020).
[35] Department of Commerce, Initial Comments at 4 (January 29, 2020).
[36] Department of Commerce, Initial Comments at 5 (January 29, 2020).

distribution grid: cyber security measures, increased monitoring of the distribution grid, contingency plans, and equipment replacement.[37]

The second planning objective – Enable greater customer engagement, empowerment, and options for energy services – was met mostly in relation to the Association's discussion surrounding its Advanced Grid Infrastructure (AGi) Project, which is anticipated to provide members with energy use and information to help empower them to find ways to save energy and money.[38] Following a discussion on the AGi project and the principle of transactive energy, the Department determined that DEA "provided extensive information and discussion of items related to the second planning objective."[39]

For the third planning objective, the Department concluded that the Association provided summaries of foundational, legacy programs that have led to new program offerings.[40] Specifically, the Department highlighted the Wellspring Renewable Energy program leading to a solar PV program for members; the availability of load management with certain members using its Supervisory Control and Data Acquisition (SCADA) system; voltage and energy use details in 15-minute increments every four hours provided via SCADA for substations and about 10% of feeders; and the potential of future monitoring, communication, and control of the grid architecture via their AGi system.[41]

The Department highlighted the Association's efforts in meeting the fourth planning objective to ensure that grid investments are used to the best of their ability to minimize system costs. Section D, pages 74 – 76, of their IDP is where Dakota Electric discussed future investments and consideration of their AGi Project, which involved spending a comparable amount of money in maintaining and installing either old infrastructure or routing those investments to assets that could have additional benefits and services with improved operational capabilities.[42] The Association also noted that the lifetime costs of AGi are expected to be more than offset by benefits received.[43]

The fifth planning objecting relating to the utility's short-term and long-term distribution system plans, costs and benefits, and ratepayer costs and benefits were also provided in the report, but the Department deferred to the Commission as to whether more details are needed.[44]

The Department recommends the Commission require the following:

> Dakota Electric shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including:

[37] Dakota Electric Association, Reply Comments at 7-9 (February 19, 2019).
[38] Department of Commerce, Initial Comments at 5 (January 29, 2020).
[39] Department of Commerce, Initial Comments at 7 (January 29, 2020).
[40] Department of Commerce, Initial Comments at 7 (January 29, 2020).
[41] Department of Commerce, Initial Comments at 7-8 (January 29, 2020).
[42] Department of Commerce, Initial Comments at 8 (January 29, 2020).
[43] Department of Commerce, Initial Comments at 8 (January 29, 2020).
[44] Department of Commerce, Initial Comments at 9 (January 29, 2020).

A. An analysis of how the information presented in the IDP related to each Planning Objective,
B. The location in the IDP,
C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives

This recommendation is identified in **Decision Option 2**. Dakota Electric does not support this recommendation due to the additional work it would require and recommends including specific questions for the information requested. As an example, the first planning objective includes resilience and security; however, the Cooperative was not clear what information was specifically requested on these broad topics.[45]

The Department presented three sound notions: first, these initial reports are foundational and serve as a baseline to which future IDP Reports can be compared, with the expectation that assessments related to the value of the distribution system planning process generally as well as specific IDP requirements can be drawn in future reports in a more comprehensive and measured effort.[46] Second, there is both efficiency and benefits in establishing consistent IDP requirements between utilities, which could lead to best practices, lessons learned, and more streamlined reviews with uniform and transparent cost benefit analyses.[47] Third, there should be "a focus on improvements that are likely to be beneficial to ratepayers regardless of the speed or scale of the technological change affecting the distribution system," the "low-hanging fruit" of the distribution system.[48]

The Department recommends the Commission amend IDP Requirement 3.D.2 (xi) of Dakota Electric Association's IDP Requirements to read as follows:

> For each grid modernization project in its 5-year Action Plan, require Dakota Electric Association to provide a cost-benefit analysis <u>based on the best information it has at the time and include a discussion of non-quantifiable benefits. Dakota Electric Association shall provide all information to support its analysis.</u>

This recommendation is captured in **Decision Option 3**. Dakota Electric does not object to this recommendation; however, the Cooperative remains concerned requiring a cost-benefit analysis for each grid modernization project could create significant additional cost to its members. Dakota Electric highlights this as an example of clarifying whether the term "grid modernization project" means only major investments, like the AGi, or normal distribution system updates or additions. If the latter, the resources required to comply would negatively impact service to Dakota Electric's members. Dakota Electric suggests providing a framework or

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[45] Dakota Electric Association, Reply Comments at 4-5 (February 19, 2020).
[46] Department of Commerce, Initial Comments at 11 (January 29, 2020).
[47] Department of Commerce, Initial Comments at 11 (January 29, 2020).
[48] Department of Commerce, Initial Comments at 11 (January 29, 2020).

use cases for cost-benefit analysis would support the Cooperative's ability to provide the most useful information.[49]

The Department identifies a minor error under the Planning Objectives section of the IDP filing requirements for all rate-regulated utilities, including Dakota Electric and recommends the Executive Secretary delete the word "annual" given IDPs are now filed biannually (**Decision Option 4**).[50]

b. Dakota Electric Association

Dakota Electric is very interested in learning what portions of report are the most useful as well as knowing how the data and information will be applied to achieve the stated purposes identified by the Commission.[51] "[A] better understanding of the different use cases for the information would help with how the information is gathered and reported by the Cooperative in future IDP reports."[52] The Association also notes simple terms can be interpreted differently and it would be helpful to develop a common understanding among parties.

For changes in future reporting, Dakota Electric shared four suggestions. Staff summarized them below: [53]

1. Create a process where Dakota Electric could engage with Commission staff and/or a stakeholder group to further refine the questions to ensure understanding and correct reporting.
2. Commission staff, utilities, and stakeholders work together, face-to-face, to review and refine the next set of questions for the 2021 IDP report. (Related to the work group suggestion captured in **Decision Option 5**.)
3. Modify the capital project reporting categories to better align with the existing typical utility categories used by Dakota Electric. It is difficult for Dakota Electric to consistently provide this data by the categories requested as the Association accounts for capital spending not by "why" but "what" was constructed. This requires significant additional manual handling of each of the individual work orders to estimate the separation of costs between the requested categories. An example given by the Association was for a new service connection where the cost of the meter is included in the service connection work order – the crew is dispatched to connect the wires and at the same time set the meter. The labor for both operations are done with the same crew and separating the labor costs between two different categories would only be estimated.
4. Discuss which projects should be allocated to which of the reporting categories to help provide more consistency within the reporting process.

The Department responded in reply to these recommendations. First, the Department may support Dakota Electric's recommendation for a face-to-face workgroup; however, stresses the

[49] Dakota Electric, Reply Comments at 6 (February 19, 2020).
[50] Department of Commerce, Reply Comments at 6, 7 (February 19, 2020).
[51] Dakota Electric, Comments at 3 (January 29, 2020).
[52] Dakota Electric, Comments at 3 (January 29, 2020).
[53] Dakota Electric, Comments at 3-5 (January 29, 2020).

need for an administrative record given the expectation that the less formal interactive process would lead to proposals for material and substantive changes to IDP filing requirements established by Commission Order. Second, the Department summarizes the previous record noting the financial categories established in the IDP filing requirements were based on Dakota Electric's previous recommendation and the Association did not demonstrate how such reporting was not yet practicable or cost-prohibitive. That said, the Department is not opposed to participating in discussions to refine IDP filing requirements assuming a written record follows to form the basis for any changes to the Commission's approved requirements.[54] The Department also does not object to Dakota Electric's request to allow minimum load at the substation rather than feeder level (**Decision Option 6**).[55]

Finally, Dakota Electric expressed their concern regarding the "the large amount of effort required to gather the information requested and to produce the IDP report."[56] In fact, labor had to be redirected from important projects in order to produce the report, while also relying on "substantial consulting assistance."[57] Therefore, the Association "asks that consideration is given to the amount of effort required to produce the data and information when questions are created for future IDP reports."[58]

c. Clean Energy Economy Minnesota

Clean Energy Economy Minnesota (CEEM) provided initial comments in support of the first IDP. "The Commission should accept DEA's Integrated Distribution plan. DEA's inaugural IDP represents a solid foundation for facilitating stakeholder dialogue related to grid modernization…We recommend that the Commission approve the IDP and utilize the outputs from the plans to inform related Commission processes and proceedings."[59]

CEEM asked the Commission to clarify how the IDP informs other dockets such as rate cases, certification requests, and other processes before it provided five recommendations to improve future filings[60]:

- Ensure all utilities are considering how energy data will connect consumers to the distribution grid in evaluating IDP filings. The Association's foundational investments in AGi, member portal and ability for members to share usage data with third parties are important steps. Engaged customers could lower demands on the distribution system. Thus, customer-facing investment(s) may alter the costs and benefits of alternative spending on the distribution system.
- DER adoption forecasts will and must become more refined. The Association's approach provides transparency in how the company approaches scenarios and is a

[54] Department of Commerce, Reply Comments at 3 (February 19, 2019).
[55] Department of Commerce, Initial Comments at 14 (January 29, 2020).
[56] Dakota Electric, Comments at 6 (January 29, 2020).
[57] Dakota Electric, Comments at 6 (January 29, 2020).
[58] Dakota Electric, Comments at 6 (January 29, 2020).
[59] Clean Energy Economy Minnesota, Comments at 2-3 (January 29, 2020).
[60] Clean Energy Economy Minnesota, Comments at 4-5 (January 29, 2020).

solid starting point for stakeholder input. Future filings may consider whether DSM has value in higher DER penetration scenarios.

- Non-wires alternatives (NWA) will receive more examination in future filings. The Association's filing presents a solid examination of how the company may consider NWAs going forward.
- Cost-benefit analysis plays a critical role in transparent IDP discussions and decision-making. Future plans should provide stakeholders and the Commission with more explicit information on cost-benefit conceptualization, methodologies and/or calculations.
- More detail and refinement of the Association's vision.

Dakota Electric appreciated the favorable observations offered by CEEM and shares an interest in identifying cost-effective NWA solutions. Dakota Electric is working toward developing NWA solutions as tools which can be used by distribution engineers to solve distribution system issues when they are identified.[61] CEEM underscored their view that NWA discussions should be discussed across all utilities and encouraged stakeholders and the Commission to monitor NWA trends while refining expectations and approaches.[62] Dakota Electric agreed an information exchange among utilities is key to NWA solutions being utilized.[63]

In expressing which IDP filing requirement provides the most value, CEEM shared its belief that IDPs will improve discussion of costs and benefits of potential system designs and associated investments. CEEM also suggested that agencies, organizations, stakeholders, and the Commission can help provide analytical and policy support.[64]

Finally, CEEM encouraged the Commission to consider other benefits outside the IDP filing requirements, such as clean energy as it provides a significant public benefit. The Commission should create "communities of practice" and learn from all stakeholders as the IDP process evolves.[65] The Department agrees and notes the IDP process has the potential to: address the informational asymmetry between stakeholders, regulators and utilities; enable more transparent planning processes and expenditures of ratepayer funds; and help all involved learn best practices and share lessons learned.[66]

d. Rakon Energy

Rakon Energy provided a public comment specific to the Association's Energy Storage System (ESS) cost estimates presented in their IDP filing. "Energy Storage costs assumption is a cause for concern. It is possible to exchange cost information with other Minnesota utilities using an idea like Emerging Technologies Coordinating Council (ETCC)."[67] Rakon Energy shared data points to contradict the $600,000 per MWh energy storage costs asserted in the IDP in

[61] Dakota Electric Association, Reply Comments at 10 (February 19, 2020).
[62] Clean Energy Economy Minnesota, Comments at 5 (January 29, 2020).
[63] Dakota Electric Association, Reply Comments at 10 (February 19, 2020).
[64] Clean Energy Economy Minnesota, Comments at 5 (January 29, 2020).
[65] Clean Energy Economy Minnesota, Comments at 6 (January 29, 2020).
[66] Department of Commerce, Reply Comments at 2 (February 19, 2020).
[67] Public Comment, Rakon Energy at 3 (January 27, 2020).

Attachment B of their comments. Rakon shared energy storage costs that ranged from $400-600 per kWh and listed resources that Dakota Electric could utilize moving forward.[68] Dakota Electric replied noting the information provided by Rakon Energy supported the Cooperative's cost estimates and agreed more information on storage use cases and costs would be valuable.[69]

Rakon Energy also provided a list of six installations where battery energy storage is coupled with water and wastewater treatment plants throughout the U.S. From these examples, Rakon wished to demonstrate the opportunity that Dakota Electric Association could have with Dakota County that would create "a near-term opportunity to give energy storage a chance."[70] Dakota Electric replied agreeing DER is a viable option to support and back up electric needs of water supply and highlighted Apple Valley, Burnsville, Eagan and Lakeville have all installed DER systems to support wells and water treatment facilities during emergencies. The same DER are used to reduce electric usage during period of peak electrical demands. Further, Dakota Electric cooperates with several members, including the City of Eagan, to support campus microgrids remotely controlled and operated by the Cooperative which annually save millions of dollars in reduced power costs.[71]

Finally, Rakon Energy suggested the Association should track cost trends for energy storage and listed two resources – EEI and the creation of an Emerging Technologies Coordinating Council – on page 10 of their comments. Dakota Electric replied that the Cooperative appreciated the information provided by Rakon Energy and would consider that information in future analysis.[72]

## VI. Staff Analysis

The Commission's filing requirements for Dakota Energy Association's IDP note 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." Staff acknowledge this deadline was not met due extenuating circumstances. All parties agree the Commission should accept Dakota Electric's IDP (**Decision Option 1**).

Given the tremendous effort and insights offered in Dakota Electric's 2019 IDP, staff offer some notes in addition to the thoughtful comments offered by parties. Staff also discuss the decision options that are contested.

[68] Public Comment, Rakon Energy at 3 (January 27, 2020).
[69] Dakota Electric Association, Reply Comments at 11-12 (February 19, 2020).
[70] Public Comment, Rakon Energy at 6-8 (January 27, 2020).
[71] Dakota Electric Association, Reply Comments at 12-13 (February 19, 2020).
[72] Dakota Electric Association, Reply Comments at 12 (February 19, 2020).

Existing Distributed Energy Resources

Dakota Electric's IDP had the most robust inventory of DER of all IDPs received this year; including both generation and load by not only number and capacity but also by location (substation and feeder). Dakota Electric's IDP also offered insight into anticipated performance of the load management DER. This type of situational awareness assists the Cooperative and its members in utilizing DER to optimize the distribution system to reduce peak demand and costs.

Preliminary Hosting Capacity Data

Dakota Electric requests the Commission allow the Cooperative to provide only substation minimum load data for the reasons explained above (**Decision Option 6**). Nothing in the IDP filing requirements precludes Dakota Electric from reporting substation minimum load data if the Cooperative explains why feeder level data is currently cost-prohibitive. The proactive inclusion of substation data and the rationale of the limiting factor substation loading plays is valuable insight for the Commission to consider. If the Commission chooses to adopt this recommendation as replacing feeder level with a substation level requirement, staff offer the filing requirement edit needed at 3.B.1 of Dakota Electric's IDP filing requirements:

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

DER Scenario Analysis

DER Scenario Analysis is typically used to examine alternative forecasts if DER adoption grows at a pace different than the base assumption. Those forecasts then inform planning related to generation and grid needs as scenarios; however, this would require coordination with the distribution Cooperative's partners in generation and transmission. It may be the case given Dakota Electric's unique position as a distribution-only Cooperative this type of DER Scenario Analysis has less value. This would seem true especially if the Cooperative and its members continued to proactively seek NWAs like the existing load management program. However, at some penetration of DER, generation and transmission planning will be impacted. Dakota Electric describes an iterative, ongoing collaboration with Great River Energy for planning purposes. Further, Dakota Electric was the only utility to incorporate time (roughly via minimum loading assumptions) and location into the DER Scenario Analysis.

Staff note Dakota Electric's alternative analysis in this section provides valuable insights for the Cooperative and its members. Staff caution that the analysis done resembles a hosting capacity analysis but does not seem to include the same number of potential limiting factors.

Modifications to Filing Requirement and Workgroup

For each of the other rate-regulated utilities' IDP filing requirements, the Commission has adopted similar language to **Decision Option 2** which asks the utility to evaluate how the IDP addresses the Planning Objectives; however, it was not contested. Dakota Electric is in opposition and would prefer the Commission identify specific additional questions to address. If the Commission wishes to adopt this decision option, it may be beneficial to discuss the level of effort and the type of information required for this new requirement to address the Cooperative's concerns.

No one opposes **Decision Option 3**; however, Dakota Electric asks for clarification on what level of "grid modernization project" triggers this type of cost-benefit analysis. Dakota Electric is comfortable if the requirement is for major projects like the AGi, but not if it is intended for traditional distribution projects. To date, the cost-benefit analysis has not been completed for traditional asset renewal or capacity addition investments by the other utilities, but cost-benefit analysis has been provided for grid modernization projects not as large as an AMI rollout (e.g. Fault Location Isolation and Restoration software and associated equipment).

The Department's recommendation to correct a minor edit found in all rate-regulated utilities' IDP filing requirements (**Decision Option 4**) came in reply and was not addressed by other parties. Staff supports this edit which improves accuracy of the IDP filing requirements and has no negative impact on utilities or stakeholders.

Dakota Electric recommends a process that includes representatives from each of the regulated utilities and stakeholders to work collaboratively to review and discuss the Commission's IDP orders for the next round of IDP reports to help ensure that data included in future IDPs is efficiently gathered and presented (**Decision Option 5**). Specifically, Dakota Electric is looking for common understanding of terms and more insight into how data reported will be used. CEEM has similarly asked the Commission for more discussion or guidance on how the IDP process fits within the utility and other dockets before the Commission. Nothing precludes the Commission from convening a discussion at a planning meeting nor a utility from including these topics in the IDP stakeholder engagement. Staff modified Dakota Electric's recommendation to clarify how such a process would be convened if the intent is for the Commission to convene. The Department's precaution is correct that such a process cannot formerly change IDP filing requirements without Commission action and an associated written record; however, Dakota Electric appears to be focused on clarifying rather than changing the IDP filing requirements at this time and recognizes a written record may follow such discussion. Staff notes other stakeholders, including the other rate-regulated utilities, who presumably would be expected to participate have not weighed in on this recommendation at the time of publishing these briefing papers.

## VII. Decision Options

1. Accept Dakota Electric's 2019 Integrated Distribution Plan. Acceptance is not a prudency determination of any proposed system modifications or investments. (*Dakota Electric Association, Department, CEEM)*

2. Require Dakota Electric to discuss in future filings how the IDP meets the Commission's Planning Objectives, including: (*Department)*
   a) Analysis of how the information in the IDP relates to each Planning Objective,
   b) The location in the IDP,
   c) Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
   d) Suggestions as to any refinements to the IDP filing requirements that would enhance Dakota Electric's ability to meet the Planning Objectives.

3. Amend IDP Requirement 3.D.2 (xi) of Dakota Electric Association's IDP Requirements to read as follows: *(Department)*

   > For each grid modernization project in its 5-year Action Plan, require Dakota Electric Association to provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Dakota Electric Association shall provide all information to support its analysis.

4. Correct Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Energy Association's IDP filing requirements in the second paragraph under Planning Objectives as shown: (*Department with staff modification to verb tense)*

   > Commission review of ~~annual~~ distribution system plans ~~are~~ is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.

5. Delegate to the Executive Secretary to convene a process to engage representatives from each of the rate-regulated utilities and stakeholders to review and discuss the Commission's IDP orders for the next round of IDP reports to help ensure that data included in future IDPs is efficiently gathered and presented. (*Dakota Electric with staff modification to delegate to the Executive Secretary*)

6. Modify IDP Requirement 3.B.1 of Dakota Electric Association's IDP Requirements to read as follows: (*Dakota Electric*)

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

Staff support: 1, 3, 4. Staff take no position on 2, 5, or 6.