BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of Distribution System Planning for Otter Tail Power Company	ISSUE DATE: February 20, 2019
	DOCKET NO. E-017/CI-18-253
In the Matter of Distribution System Planning for Minnesota Power	DOCKET NO. E-015/CI-18-254
In the Matter of Distribution System Planning for Dakota Electric Association	DOCKET NO. E-111/CI-18-255
	ORDER ADOPTING INTEGRATED-DISTRIBUTION-PLAN FILING REQUIREMENTS

PROCEDURAL HISTORY

At the Commission's April 19, 2018 agenda meeting, its members voted to authorize staff to issue draft integrated-distribution-planning (IDP) filing requirements for each of Minnesota's four rate-regulated utilities and to solicit stakeholder comment on the requirements.

On June 12, the Commission issued draft IDP requirements for Otter Tail Power Company (Otter Tail), Minnesota Power, and Dakota Electric Association (Dakota Electric) in the above-captioned dockets and solicited comments on each utility's draft requirements.[1]

By September 7, the Commission had received comments from the three utilities, as well as the following stakeholders:

- Fresh Energy
- Minnesota Department of Commerce, Division of Energy Resources (the Department)
- Office of the Attorney General – Residential Utilities and Antitrust Division (the OAG)
- Citizens Utility Board of Minnesota (CUB)

The utilities found the draft requirements workable for the most part, but suggested a number of modifications to tailor the requirements to their individual circumstances. Fresh Energy, the Department, the OAG, and CUB were generally supportive of the draft requirements and recommended updating them to add provisions similar to those approved for Xcel in Docket No. E-002/CI-18-251.

[1] Draft IDP requirements for the fourth utility, Xcel Energy, were issued on June 8 in Docket No. E-002/CI-18-251; the Commission adopted IDP filing requirements for Xcel by order dated August 30.

By September 28, the following parties had filed reply comments:

- The Department
- The OAG
- CUB
- Dakota Electric

On November 28, Commission staff filed updated draft IDP requirements incorporating some of the parties' recommendations, including certain provisions from Xcel's approved IDP filing requirements as recommended by the Department.

On December 6, 2018, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. The Draft IDP Requirements

The purpose of the IDP requirements is to facilitate a utility's filing of an integrated distribution plan that will:

- 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.

The updated draft IDP requirements provide that the utilities will file integrated distribution plans biennially beginning on November 1, 2019. Utilities are to hold at least one stakeholder meeting to garner public input prior to filing their plans. The updated requirements identify utility-system and financial data to be included in the plans, require utilities to evaluate varying levels of distributed-energy-resource deployment, and require utilities to provide both a five-year action plan and a ten-year long-term plan for distribution-system development.

Finally, the requirements state that if a utility deems any distribution-system information impracticable or cost-prohibitive to provide, the utility should explain:

- Why it deems the information impracticable or cost-prohibitive to provide;
- How the information could be obtained, at what estimated cost, and in what timeframe;
- What the benefits or limitations are of filing the data in future reports as related to achieving the planning objectives; and

- If the information cannot be provided in future reports, what alternative information could be provided and how it would achieve the planning objectives.

II. Commission Action

Having reviewed the record, including the draft IDP requirements and parties' comments on those requirements, the Commission finds each utility's updated draft IDP filing requirements reasonable and will adopt them in the form attached.

The IDP requirements will provide valuable insights into the utilities' distribution-planning processes and assist the Commission and stakeholders in evaluating potential investments to modernize the electric grid. Moreover, by requiring the utilities to account for different levels of distributed-energy-resource deployment, the IDP requirements will help ensure that they are prepared to accommodate new distribution-level resources.

The utilities identified potential challenges with meeting certain IDP filing requirements. For example, both Otter Tail and Dakota Electric stated that they do not track their historical distribution-system spending under the same categories used in the IDP requirements, and requested that they be allowed to report their spending under categories that more closely match the ones they currently use.

The Commission concludes that the IDP requirements adequately address this and similar situations by allowing utilities to explain why it is impracticable or cost-prohibitive for them to comply with a particular filing requirement. However, for the 2019 filing, the Commission will allow Otter Tail and Dakota Electric to provide historical distribution-system spending data in their preferred categories, as provided in the attached IDP filing requirements. In future years, the utilities will need to provide this data according to the requirements or explain why they cannot do so.

ORDER

1. The Commission hereby adopts IDP filing requirements for Otter Tail, Minnesota Power, and Dakota Electric, as attached.

2. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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MINNESOTA
PUBLIC UTILITIES COMMISSION

MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
For Otter Tail Power Company
Docket E017/CI-18-253

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; and,
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and,
- Provide the Commission with the information necessary to understand Otter Tail Power'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.

Commission review of annual distribution system plans are not meant to preclude flexibility for Otter Tail Power Company (Otter Tail) 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.

For filing requirements which Otter Tail Power claims is not yet practicable or is currently cost-prohibitive to provide, Otter Tail Power shall indicate for each requirement:

1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive;
2. How the information could be obtained, at what estimated cost, and timeframe;
3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;
4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.

Distribution System Plan Process

1. **Filing Date:** Require Otter Tail to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above.

2. **Stakeholder Meeting(s):** Otter Tail should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

At a minimum, Otter Tail should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

3. **Filing Requirements:** For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[1] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles (EV), demand side management, and energy efficiency (EE).[2]

   A. **Baseline Distribution System and Financial Data**:

   System Data

   1. Modeling software currently used and planned software deployments
   2. Percentage of substations and feeders with monitoring and control capabilities, planned additions
   3. A summary of existing system visibility and measurement (feeder-level and time) interval and planned visibility improvements; include information on percentage of the system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
   4. Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available
   5. Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans
   6. Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology
   7. Discussion if and how IEEE Std. 1547-2018[3] impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.
[2] ICF Report, Integrated Distribution Planning, August 2016, prepared for Minnesota Public Utilities Commission, Docket No. E999/CI-15-556, available online: [See eDockets ID: 20169-124836-01.]
[3] IEEE Standard 1547-2018, published April 6, 2018.

8. Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)
9. The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems
10. Total distribution substation capacity in kVA
11. Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.
12. Total miles of overhead distribution wire
13. Total miles of underground distribution wire
14. Total number of distribution customers
15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc).
16. Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)
17. Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
18. Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
19. Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
20. Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
21. Total number of electric vehicles in service territory
22. Total number and capacity of public electric vehicle charging stations
23. Number of units and MW/MWh ratings of battery storage
24. MWh saving and peak demand reductions from EE program spending in previous year
25. Amount of controllable demand (in both MW and as a percentage of system peak)

Financial Data

26. Historical distribution system spending for the past 5-years, in each category:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects

f. Projects related to local (or other) government-requirements
g. Metering
h. Other

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

a. New Load or Reliability
b. Replace
c. Relocate
d. Metering
e. Grid Modernization or Pilot Projects

27. All non-Otter Tail investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).
28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
29. Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Projects related to local (or other) government-requirements
    g. Metering
    h. Other

30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement

DER Deployment

31. Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)
32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers “high” DER penetration.
33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.

B. Preliminary Hosting Capacity Data

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

C. Distributed Energy Resource Scenario Analysis

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

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

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

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

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

1. Otter Tail shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity analysis/daytime minimum load data, and non-wires alternatives analysis.
2. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Otter Tail

[4] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶61,127 (February 28, 2018)

should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:

i. Overview of investment plan: scope, timing, and cost recovery mechanism
ii. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[5]
iii. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.
iv. System interoperability and communications strategy
v. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.)
vi. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
vii. Customer anticipated benefit and cost
viii. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
ix. Plans to manage rate or bill impacts, if any
x. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt)
xi. For each grid modernization project in its 5-year Action Plan, Otter Tail Power should provide a cost-benefit analysis
xii. Status of any existing pilots or potential for new opportunities for grid modernization pilots

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

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

1. Otter Tail shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than

[5] https://gridarchitecture.pnnl.gov/

two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

2. Otter Tail shall provide information on the following:
   i. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
   ii. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
   iii. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
   iv. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.

MINNESOTA
PUBLIC UTILITIES COMMISSION

MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
For Minnesota Power
Docket E015/CI-18-254

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

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- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs, and,
- Provide the Commission with the information necessary to understand Minnesota Power'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.

Commission review of annual distribution system plans are not meant to preclude flexibility for Minnesota Power Company (Minnesota Power) 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.

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4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.

Distribution System Plan Process

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2. **Stakeholder Meeting(s):** Minnesota Power should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

At a minimum, Minnesota Power should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

3. **Filing Requirements:** For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[1] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles (EV), demand side management, and energy efficiency (EE).[2]

A. Baseline Distribution System and Financial Data:

System Data

1. Modeling software currently used and planned software deployments
2. Percentage of substations and feeders with monitoring and control capabilities, planned additions
3. A summary of existing system visibility and measurement (feeder-level and time) interval and planned visibility improvements; include information on percentage of the system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
4. Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available
5. Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans
6. Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology
7. Discussion if and how IEEE Std. 1547-2018[3] impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)

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[1] See *Minnesota Staff Grid Modernization Report, March 2016*.
[2] ICF Report, Integrated Distribution Planning, August 2016, prepared for Minnesota Public Utilities Commission, Docket No. E999/CI-15-556, available online: See eDockets ID: 20169-124836-01.
[3] IEEE Standard 1547-2018, published April 6, 2018.

8. Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)
9. The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
10. Total distribution substation capacity in kVA
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12. Total miles of overhead distribution wire
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15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc).
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17. Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
18. Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
19. Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
20. Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
21. Total number of electric vehicles in service territory
22. Total number and capacity of public electric vehicle charging stations
23. Number of units and MW/MWh ratings of battery storage
24. MWh saving and peak demand reductions from EE program spending in previous year
25. Amount of controllable demand (in both MW and as a percentage of system peak)

Financial Data

26. Historical distribution system spending for the past 5-years, in each category:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects

f. f. Projects related to local (or other) government-requirements (road-relocations, etc.) g. Metering
g. h. Other

27. All non-Minnesota Power investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).
28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Projects related to local (or other) government-requirements
    g. Metering
    h. Other

30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement

DER Deployment

31. Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)
32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.
33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.

B. Preliminary Hosting Capacity Data

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

C. Distributed Energy Resource Scenario Analysis

1. In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased

DER deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Minnesota Power distribution system in the locations Minnesota Power would reasonably anticipate seeing DER growth take place first.

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

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

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

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

1. Minnesota Power shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (topics and categories listed above). Minnesota Power should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:

    a. Overview of investment plan: scope, timing, and cost recovery mechanism
    b. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[5]

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[4] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶61,127 (February 28, 2018)
[5] https://gridarchitecture.pnnl.gov/

c. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.
d. System interoperability and communications strategy
e. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.)
f. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
g. Customer anticipated benefit and cost
h. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
i. Plans to manage rate or bill impacts, if any
j. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt)
k. For each grid modernization project in its 5-year Action Plan, Minnesota Power should provide a cost-benefit analysis
l. Status of any existing pilots or potential for new opportunities for grid modernization pilots

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

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

1. Minnesota Power shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.
2. Minnesota Power shall provide information on the following:
    a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
    b. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)

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

d. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.

MINNESOTA PUBLIC UTILITIES COMMISSION

MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
For Dakota Electric Association
Docket E111/CI-18-255

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

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

Commission review of annual distribution system plans are not meant to preclude flexibility for Dakota Electric 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.

For filing requirements which Dakota Electric claims is not yet practicable or is currently cost-prohibitive to provide, Dakota Electric shall indicate for each requirement:

1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive;
2. How the information could be obtained, at what estimated cost, and timeframe;
3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;
4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.

Distribution System Plan Process

1. **Filing Date:** Require Dakota Electric to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above.

2. **Stakeholder Meeting(s):** Dakota Electric should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

   At a minimum, Dakota Electric should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

3. **Filing Requirements:** For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[1] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.[2]

   A. **Baseline Distribution System and Financial Data**:

   System Data

   1. Modeling software currently used and planned software deployments
   2. Percentage of substations and feeders with monitoring and control capabilities, planned additions
   3. A summary of existing system visibility and measurement (feeder-level and time) interval and planned visibility improvements; include information on percentage of the system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
   4. Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available
   5. Discussion of how Dakota Electric Association approaches distribution system planning in consideration of and coordination with Great River Energy's integrated resource plan, and any planned modifications or planned changes to the existing process to improve coordination and integration between the two plans from Dakota Electric Association's perspective.
   6. Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology
   7. Discussion if and how IEEE Std. 1547-2018[3] impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)
   8. Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)

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[1] See *Minnesota Staff Grid Modernization Report, March 2016*.
[2] ICF Report, Integrated Distribution Planning, August 2016, prepared for Minnesota Public Utilities Commission, Docket No. E999/CI-15-556, available online: See eDockets ID: 20169-124836-01.
[3] IEEE Standard 1547-2018, published April 6, 2018.c

9. The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
10. Total distribution substation capacity in kVA
11. Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.
12. Total miles of overhead distribution wire
13. Total miles of underground distribution wire
14. Total number of distribution customers
15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc).
16. Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)
17. Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
18. Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
19. Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
20. Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
21. Total number of electric vehicles in service territory
22. Total number and capacity of public electric vehicle charging stations
23. Number of units and MW/MWh ratings of battery storage
24. MWh saving and peak demand reductions from EE program spending in previous year
25. Amount of controllable demand (in both MW and as a percentage of system peak)

Financial Data

26. Historical distribution system spending for the past 5-years, in each category:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Projects related to local (or other) government-requirements (road-relocations, etc.)
    g. Metering
    h. Other

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

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

27. All non-Dakota Electric investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).
28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
29. Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Projects related to local (or other) government-requirements
    g. Metering
    h. Other

30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement

DER Deployment

31. Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)
32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration
33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.

B. Preliminary Hosting Capacity Data

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

C. Distributed Energy Resource Scenario Analysis

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

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

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

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

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

1. Dakota Electric shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including

[4] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶61,127 (February 28, 2018)

load growth assumptions) and the costs of distribution system investments planned for the next 5-years (topics and categories listed above). Dakota Electric should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:

i. Overview of investment plan: scope, timing, and cost recovery mechanism
ii. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[5]
iii. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.
iv. System interoperability and communications strategy
v. Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.)
vi. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
vii. Customer anticipated benefit and cost
viii. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
ix. Plans to manage rate or bill impacts, if any
x. Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt)
xi. For each grid modernization project in its 5-year Action Plan, Dakota Electric should provide a cost-benefit analysis
xii. Status of any existing pilots or potential for new opportunities for grid modernization pilots

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

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

[5] https://gridarchitecture.pnnl.gov/

1. Dakota Electric shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

2. Dakota Electric shall provide information on the following:
   i. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
   ii. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
   iii. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
   iv. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.