MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date:	December 6, 2018	Agenda Item **6 (OTP), **7 (MP), **8 (DEA)
Company:	Otter Tail Power, Minnesota Power and Dakota Electric Association	
Docket No.	E017/CI-18-253, E015/CI-18-254, E111/CI-18-255	

In the Matter of Distribution System Planning for Otter Tail Power Company; In the Matter of Distribution System Planning for Minnesota Power; and In the Matter of Distribution System Planning for Dakota Electric Association

Issues: Should the Commission require Integrated Distribution Plan (IDP) filings on November 1, 2019 from Otter Tail, Minnesota Power and Dakota Electric Association? Should the Commission take some other action?

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Relevant Documents	**Date**
PUC – Briefing Papers for April 19, 2018 Agenda	April 11, 2018
Citizen's Utility Board – Initial Comments	September 7, 2018
OAG-RUD – Initial Comments	September 7, 2018
Citizens Utility Board - Reply Comments	September 28, 2018
Relevant Documents – Docket Specific	
Otter Tail Power – Docket 18-253	
PUC – Notice of Comment Period on OTP Draft IDP Requirements	June 12, 2018
Fresh Energy – Comments	September 4, 2018
Otter Tail Power – Comments	September 7, 2018

Relevant Documents	**Date**
DOC DER – Comments	September 7, 2018
OAG-RUD – Reply Comments	September 28, 2018
DOC DER – Reply Comments	September 28, 2018
Minnesota Power – Docket 18-254	
PUC – Notice of Comment Period on MP Draft IDP Requirements	June 12, 2018
Fresh Energy – Comments	September 4, 2018
Minnesota Power – Comments	September 7, 2018
DOC DER – Comments	September 7, 2018
Minnesota Power – Supplemental Comments	September 24, 2018
OAG-RUD – Reply Comments	September 28, 2018
DOC DER – Reply Comments	September 28, 2018
Dakota Electric Association – Docket 18-255	
PUC – Notice of Comment Period on DEA Draft IDP Requirements	June 12, 2018
Dakota Electric Association – Comments	September 7, 2018
DOC DER – Comments	September 7, 2018
Dakota Electric Association – Reply Comments	September 27, 2018
OAG-RUD – Reply Comments	September 28, 2018
DOC DER – Reply Comments	September 28, 208

I. Statement of the Issues

Should the Commission require Integrated Distribution Plan (IDP) filings on November 1, 2019 from Otter Tail, Minnesota Power and Dakota Electric Association? Should the Commission take some other action?

II. Docket Background

In March 2016, the Commission released the *Staff Report on Grid Modernization* (2016 Staff Report).[1] The 2016 Staff Report outlined a phased process and potential options for the Commission to pursue in its investigation into the state's grid modernization efforts. At that time, Commissioners supported distribution system planning as the most reasonable and actionable way for the Commission to assist in the forthcoming grid evolutions. Commissioners agreed with the creation of a comprehensive, coordinated, transparent, and integrated distribution system planning process in Minnesota and supported the staff proposed principles to guide further work[2]:

- 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.

In August 2016, the Commission received a report, *Integrated Distribution System Planning*, completed by ICF International based on funding provided by the Department of Energy.[3] Following release of the report, the Commission held a workshop on October 24, 2016 seeking stakeholder input and discussion on a Minnesota-based distribution system planning framework.[4]

In April 2017, the Commission issued a questionnaire to utilities and stakeholders seeking to understand (1) how utilities currently plan their distribution system, (2) the status of each utility's current-year plan, and (3) how utilities and stakeholders recommend current distribution system planning processes could be improved.

Through September 2017, the Commission received in-depth responses on each utility's planning process, current plans, and utility and stakeholder input on potential topics and process considerations for distribution system planning. It was realized in early 2018, that due to utility differences in: geography, territory, size, and status in grid modernization, among several other

[1] Docket No. E999/CI-15-556
[2] MN PUC Staff Report on Grid Modernization, March 2016
[3] Integrated Distribution Planning Report, August 2016 (ICF Report)
[4] MN PUC Grid Modernization: Distribution Planning Workshop Slides, Oct. 24, 2016

factors, it was reasonable to set requirements individually by utility in order to request information from each utility that was adaptable to their current state and be modifiable overtime.

In April 2018, Commission staff established individual dockets and publically released draft proposed utility-specific filing requirements for Commission review, seeking Commission input and authorization to release the Draft-IDP for utility and stakeholder comment. The Commission directed staff to meet with each utility to discuss and clarify the filing requirements and following, authorized the release of the utility-specific draft integrated distribution plan filing requirements (Draft-IDP) for each utility.[5] Staff met with utilities throughout April and May 2018 to answer questions and/or provide clarity and released each utility's Draft-IDP for comment in June 2018.[6]

By September 7, 2018, comments were received on Minnesota Power (MP), Otter Tail Power (OTP), Dakota Electric Association (DEA) Draft-IDPs from each utility on their own filing requirements, the Citizens Utility Board of Minnesota (CUB), Minnesota Department of Commerce- Division of Energy Resources (DOC DER), Fresh Energy (FE), and the Office of the Attorney General – Residential Utilities Division (OAG-RUD).

In this paper, staff provide a brief overview of party positions in Section III and discuss a few filing requirement changes in Section IV (which are discussed in more depth in Attachment A).

Attached to this paper are:

- Attachment A: Summary of Party Proposed Edits and Staff Responses
- Attachment B: Staff Proposed IDP Filing Requirements for OTP (with Redline Version)
- Attachment C: Staff Proposed IDP Filing Requirements for MP (with Redline Version)
- Attachment D: Staff Proposed IDP Filing Requirements for DEA (with Redline Version)

III. Overview of Stakeholder Positions

A summary of stakeholder positions is below, more detailed information about stakeholder comments on specific filings requirements is included in Appendix A. Some entities provided comments general encompassing all three dockets, and therefore, staff has compiled the comments into one briefing paper that addresses all three dockets, to reduce redundancy.

A. Citizens Utility Board of Minnesota

CUB was supportive of the Commission's initiative and the Draft-IDP requirements as it would allow evaluation of grid investments and costs and would help identify which benefits should be captured for customers.[7] CUB participated in the Commission's evaluation of IDP requirements for Xcel Energy and supported utilization of the requirements adopted for Xcel

[5] April 19 Agenda Meeting Minutes, Docket Nos. 18-251 (Xcel Energy), 18-253 (Otter Tail Power), 18-254 (Minnesota Power), 18-255 (Dakota Electric Association)

[6] The June 2018 Xcel Draft-IDP Filing Requirements is included to this briefing paper as a relevant document.

[7] CUB Initial, pg. 1

for the three remaining IOUs. CUB noted that while the plans will likely diverge overtime, the requirements put forth at this time, could be applicable to all utilities.

CUB did not support any of the modifications proposed by DEA, MP or OTP in the initial comment period, as the filing requirements "do not demonstrate additional improvements to the process, in favor of the public interest."[8] CUB was supportive of the process, and information requirements, as proposed by staff, as a reasonable way to allow flexibility in reporting (allowing explanations when data cannot be provided due to impracticality or cost-prohibition).[9]

B. Department of Commerce Division of Energy Resources

DOC DER was supportive of the IDP process and provided comments specific to each utility, noting that "it is important to adapt IDP requirements to the unique circumstances and characteristics of each utility such that a completely uniform set of requirements is likely precluded."[10] DOC DER acknowledged that DERs are being added to the system and it is prudent to plan for the coming system transformation. DOC DER noted its focus was: 1) to stress the importance of cost-effectiveness in the distribution system planning processes and in the outcome of distribution planning; 2) to indicate support for seeking information about distribution system planning; and 3) to advocate for consistent IDP requirements between utilities to the greatest extent practicable[11] however acknowledged concern about inconsistent criteria being used to assess differing utilities cost and benefits.[12]

DOC DER provided a thorough review and analysis of each stakeholder recommendation; DOC DER specific recommendations (and requests for clarifications) are included in the filing requirement sections below.

C. Fresh Energy

Fresh Energy filed initial comments and noted the Draft-IDP requirements are reasonable, they generally supported staff's proposals for each utility, and recommended that the Commission adopt for the MP and OTP IDPs the modifications ordered by the Commission for the Xcel IDP to the extent they are applicable to MP and OTP.

D. Office of Attorney General – Residential Utilities Division

The Office of Attorney General-Residential Utilities Division (OAG-RUD) supports the Draft-IDP proposals as put forth by staff, recommended the Commission adopt for the DEA, MP, and OTP IDPs the modifications ordered by the Commission for the Xcel IDP as it did not see

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[8] CUB Reply at 1
[9] CUB Reply at 1-2
[10] DOC Initial, pg. 4
[11] DOC Initial, p. 2
[12] DOC Initial, p. 4

a clear basis to require different requirements than those approved for Xcel. Specifically, OAG-RUD recommended that the Commission adopt the additional objective proposed by OAG-RUD, as modified by staff:

> Provide the Commission with the information necessary to understand [utility] short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

And second, the OAG-RUD recommended the Commission require that for each grid modernization project in a utility's 5-year Action Plan, it be required to file a cost-benefit analysis. In reply, the OAG-RUD weighed in on each utility's request to modify certain plan requirements (discussed further in Attachment A).

E. Dakota Electric Association

Dakota Electric Association, a rate-regulated distribution-only cooperative, provided initial and reply comments. DEA provided background information about the emerging prospects of DERs on its system, and what differing futures could look like and potential distribution system benefits or impacts (depending on the type, size and location of DER adoption).[13] DEA advocates that the IDP process focus on forecasting assumptions, forecasting models and methods and that information can be incorporated into its planning processes, and that an IDP process *not* focus on specific evaluation of individual construction projects.[14] DEA noted it has concerned about limited technical staff resources and its ability to provide the requesting information at a cost that provide its customers value; that being said, DEA focused its comments and suggestions on areas in which modification could help ensure the work is commensurate with customer value (discussed further below).

DEA provided suggested modifications to the reporting requirements and in reply comments, responded to the Department's suggested modified filing requirements.

DEA generally supported a biennial filing requirement and (strongly) suggested that future reports (beyond the November 2019 report) would be better suited to be filed in March to correspond with internal deadlines and other reporting requirements.[15] Staff believes may be a reasonable request and the Commission could consider it upon the acceptance of the November 2019 IDP (setting a filing date for the next IDP).

Last, DEA had several concerns with the inclusion of additional data filing requirements noting that it did not currently have the information and likely only estimates could be obtained at this time (EVs in territory, EV charging stations).[16]

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[13] DEA Initial, pg. 2-3
[14] DEA Initial, pg. 4
[15] DEA Reply, p. 2-3
[16] DEA Reply, p. 3

F. Minnesota Power

Minnesota Power provided initial and supplemental comments on the Draft IDP requirements. MP noted that it appreciated staff's clarifications to date, and it sought a few additional clarifications regarding some of the filing requirements (further clarified below).[17] MP noted that it found the biennial filing requirement reasonable and that is supported a 10-year outlook (versus 15-years).[18] MP submitted supplemental comments which provided an overview of their anticipated DER penetration scenarios which was inadvertently omitted from their initial comments.

G. Otter Tail Power

Otter Tail Power filed comprehensive initial comments that noted it was supportive of the process developed by staff, and appreciative of the recognition of utility differences and the flexibility included in the reporting requirements. OTP noted they provided comments in the "context of maintaining value to customers commensurate with costs."[19] At a high level, OTP requested that it be required to file only a baseline and high DER penetration scenario in its first IDP filing (versus baseline, medium, and high)[20], requested that it be required to utilize a 10-year time horizon (versus 15-years)[21], file biennially, as well as elimination of some filing requirements and modification of some requirements to make the filing requirements less onerous.[22] Last, OTP sought clarification on a few items (whether their utility definition of distribution versus transmission was reasonable for the filing requirements and further clarification of a 'non-traditional' solution).[23]

IV. Overview of Topic Areas and Staff Discussion

The comments received by stakeholders were generally much more limited than the stakeholder participation in the Xcel IDP docket. For the majority of the issues, there was large agreement between parties. No stakeholder opposed the process or indicated there was no need for IDP; all parties believed the process should continue. Utilities noted some IDP requirements may require more resources than anticipated value, and either sought clarification or proposed amendments.

V. Filing Requirement Modifications and Discussion

Below staff provide a discussion of the high level filing requirements in which parties provided comment; filing requirements in which stakeholders did not suggest changes are not listed. Specific items that were discussed in more detail are included in Attachment A – where staff has included

[17] MP Initial, p. 1-3
[18] MP Initial, p. 4
[19] OTP Initial, p.1
[20] OTP Initial, p. 1-5
[21] OTP Initial, p. 6
[22] OTP Initial, p. 6-8
[23] OTP Initial, p.7-8

the recommendation and responses by stakeholders as well as a summary of what was incorporated by staff.

Generally, staff does not address items in depth in which a utility requested a requirement be removed from the IDP. As noted by many stakeholders in response to those recommendations to remove the requirement - if the Commission adopts similar language to what was utilized in Xcel's IDP, regarding non-practicable or cost-prohibitive information – that language would provide sufficient flexibility for the utilities to inform the Commission of the current state of their system and access (or lack thereof) to certain data or resources to obtain the data.[24]

> For filing requirements which [the utility] claims is not yet practicable or is currently cost-prohibitive to provide, it shall indicate for each requirement:[25]
>
> 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.

December 6 Staff IDP Requirements: Staff has proposed that this provision be included in all three utility IDP Filings Requirements for the reasons noted above and throughout party comments, specifically, the DOC DER rational that this provision allows for flexibility by utility to ensure that the information provided is not an unreasonable burden to obtain and that it has some level of customer value for the time and resources necessary to provide it.[26] This concern of the DER-DOC was strongly articulated through the Xcel IDP docket.[27]

A. Planning Objectives

Generally parties found the Commission IDP objectives were reasonable and comprehensive way to guide the planning process. The DOC DER recommended for all three utilities[28] that the Commission adopt a fifth objective, that, in conjunction with the cost-prohibitive provision noted above, would address Department concerns regarding cost-effectiveness of distribution system planning and utilities' need for flexibility in the IDP process. This objective was proposed in the Xcel IDP docket and adopted by the Commission.[29] The addition was supported by other parties generally[30]:

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[24] See DOC DER Initial (all 3 dockets) at pg. 5

[25] See Commission Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, Docket CI-18-251.

[26] DOC DER reply (all 3 dockets), various pages.

[27] See DOC DER Initial Comments in Commission Docket CI-18-251, at pg. 3-8.

[28] DOC DER Initial (all 3 dockets) at pg. 5

[29] See Commission Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, Docket CI-18-251.

[30] OAG-RUD Initial, at 2, FE at pg. 1, CUB at pg. 2.

- Provide the Commission with the information necessary to understand Xcel'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.

No parties opposed the proposed additional objective.

December 6 Staff IDP Requirements: Staff support the inclusion of this objective and have included it for all three utilities.

B. Filing Date (Draft-IDP Section 1)

In the Commission's Notice of Comment on this matter, staff specifically requested input from parties on the reasonableness of the biennial filing requirement for the three utilities (beginning November 1, 2019) and the timeframe that the IDP should cover (either a 15-year term or a shorter time period, such as 10-years).

Utilities and stakeholders generally agreed that a 10-year timeframe was appropriate to correspond with the shorter distribution planning cycles and found that a biennial reporting process was reasonable.[31] DEA noted that a due date in March may be better aligned with internal processes, however noted that it intended to meet the initial file date of November 2019.[32]

The DOC-DER recommended in reply comments for all three utilities that a requirement be added that requires each utility to provide a detailed plan for process improvement of the IDP report development that would result in the capability to file IDP reports on an annual basis.[33]

December 6 Staff Proposed IDP Requirements: Staff has modified each of the three utility's Draft-IDP filing date requirements to require the plans cover a term of 10-years (instead of 15 years). Staff agree with the reasoning provided by all parties. Staff has not adopted the DOC-DER recommendation at this time regarding information on annual filings, as staff does not have sufficient supporting information that annual filings from these three entities will be useful in the near future, but as contemplated by the IDP process design, this issue can be revisited with the next IDP filing cycle.

C. Filing Requirements (Draft-IDP Section 3)

The filing requirements section of the Draft-IDPs for the three utilities are where most parties focused their comments. A summary of the comments provided by parties by sub-item and staff's recommendation are included in Attachment A.

[31] MP Initial, pg. 2; DEA Initial, pg. 1; OTP Initial, pg. 2.
[32] DEA Reply, pg. 2-3
[33] DOC DER Reply, pg. 3-4

Largely, staff did not significantly modify the filing requirements, other than for administrative corrections or where staff found additional clarity was needed. While each of the utilities provided differing arguments about whether a filing requirement should be modified or removed at this time, staff believes (consistent with the DOC DER's recommendations) that these items should remain in this iteration of filing requirements and the utilities should articulate why a requirement could not be furnished in each respective IDP. With the addition of the language regarding 'cost-prohibitive' or 'not practicable' information (that staff recommends be included in the filing requirements) staff believes there is sufficient latitude to the utilities in providing information or in substituting data.

Staff notes that modifications were made to the filing requirements, staff refers Commissioners to Attachment A for further detail and Attachments B-D for specific edits made to each utility filing requirements.

VI. Commission Decision Alternatives

In the Matter of Distribution System Planning for Otter Tail Power, Docket E017/CI-18-253

1. Adopt Staff's December 6 IDP Filing Requirements for OTP, as attached
2. Modify the Staff's December 6 Filing Requirements
3. Adopt Staff's June 2018 IDP Filing Requirements for OTP (not modified)
4. Take some other action

In the Matter of Distribution System Planning for Minnesota Power, Docket E015/CI-18-254

5. Adopt Staff's December 6 IDP Filing Requirements for MP, as attached
6. Modify the Staff's December 6 Filing Requirements
7. Adopt Staff's June 2018 IDP Filing Requirements for MP (not modified)
8. Take some other action

In the Matter of Distribution System Planning for Dakota Electric, Docket E111/CI-18-255

9. Adopt Staff's December 6 IDP Filing Requirements for DEA, as attached
10. Modify the Staff's December 6 Filing Requirements
11. Adopt Staff's June 2018 IDP Filing Requirements for DEA (not modified)
12. Take some other action

Staff Recommendation: 1, 5, and 9.

	Draft-IDP Requirement
	New Proposed Filing Requirement
	Stakeholder and Staff Comment (Modification)

DRAFT - MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
Summary of Stakeholder and Staff Comments on Proposed Requirements
Dockets 18-253, 18-254, and 18-255

SECTION 3A. Baseline Distribution System and Financial Data

Line	System Data	
1	3.A.1	Modeling software currently used and planned software deployments
2	3.A.2	Percentage of substations and feeders with monitoring and control capabilities, planned additions
3	3.A.3	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
4	3.A.4	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available
5	3.A.5	**OTP and MP language:** 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 **DEA language:** 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	3.A.6	Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology
7	3.A.7	Discussion if and how IEEE Std. 1547-2018[1] impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability)
8	Comments by Stakeholders:	DOC DER suggested a modification (in all three dockets) to clarify:[2] Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability <u>and advanced inverter functionality</u>).
9	Staff Response:	Staff has included this modification in all three utility IDP filing requirements as it provides additional clarity to what was intended and sought by staff when it drafted this item.
10	3.A.8	Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)

[1] IEEE Standard 1547-2018, published April 6, 2018.
[2] DOC Initial, pg. 7

11	Comments by Stakeholders:	MP requested additional clarity from staff on this item and whether the item was intended to be on a per-circuit or per-voltage basis – MP noted that the voltage would be more reasonable since the big driver in loss percentage is voltage.[3]
12	Staff Response:	Staff believes this is a reasonable interpretation and provides additional clarity. If this data is available or is tracked by a utility in some other format, as long as the data is reported with sufficient information and consistent over time, the objective of this time would be achieved.
13	3.A.9	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
14	Comments by Stakeholders:	MP requested additional clarity from staff on this item and whether the data was intended to capture system-wide coincident peak or individual peaks by substation.[4]
15	Staff Response:	Staff believe this information should be provided by individual peaks by substation (which is consistent with MP's preference) to the extent possible, where that information may be cost prohibitive or unavailable, system coincident peak should be provided. Substation coincident peak would be most useful in the immediate (and early) distribution system planning context and would allow for analysis of system utilization (and trends, overtime) when used in combination of the transformer and substation capacity (items 3.A.10 and 3.A.11, below).
16	3.A.10	Total distribution substation capacity in kVA
17	Comments by Stakeholders:	MP requested clarification the purpose of this requirement in order to provide the best possible information in response.[5]
18	Staff Response:	This information, when tracked over time and in conjunction with factors above, would allow for trends of distribution system utilization.
19	3.A.11	Total distribution transformer capacity in kVA
20	Comments by Stakeholders:	MP requested clarification the purpose of this requirement in order to provide the best possible information in response.[6]
21	Staff Response:	Same as above (3.A.10). Staff has modified this requirement as staff understands that total transformer nameplate capacity is typically equal to the total nameplate substation capacity. Total distribution transformer capacity in kVA<u>, if different from total distribution substation capacity and the reason for the difference.</u>

[3] MP Initial, pg. 2
[4] MP Initial, pg. 2
[5] MP Initial, pg. 2
[6] MP Initial, pg. 2

		Staff notes that transformer capacity is not be fully utilized in actual system operations due to several factors (abnormal condition, contingencies, seasonal load, etc.). Different utilities may have different utilitization rates inherenet in planning assumptions, requesting that data may be useful in the future.
22	3.A.12	Total miles of overhead distribution wire
23	3.A.13	Total miles of underground distribution wire
24	3.A.14	Total number of distribution customers
25	3.A.15	Total costs spent on DER generation installation in the prior year (including application review, responding to inquiries, metering, testing, make ready, etc).
26	Comments by Stakeholders:	Otter Tail noted that it does not currently track costs associated with DER generation installations and doing so would cause changes to their current internal processes.[7] DOC DER noted again, that in lieu of removing the requirement, the Commission's addition of the provision regarding cost-prohibitive or unavailable information should alleviate OTP's concern and DOC DER does not recommend modifying this requirement.[8] Additionally, the DOC DER noted that for any items that may be reported in another docket, it would be reasonable to mirror language to the extent reasonable, but not remove the items; the information could either be provided or simply referenced.
27	Staff Response:	Staff has modified the requirement in include the clarity sought (regarding the costs broken down by categories) but has kept the item in the filing requirements consistent with DOC DER's recommendation and reasoning. Staff Clarified Language: Total costs spent on DER generation installation in the prior year. <u>These costs should be broken down by category</u> (including application review, responding to inquiries, metering, testing, make ready, etc).
28	3.A.16	Total charges to customers/member installers for DER generation installations, in the prior year (including application, fees, metering, make ready, etc.)
29	Comments by Stakeholders:	OTP proposed elimination of Sections 3A 16, 17, 18, and 23 in their IDP requirements as they believed they were already sufficiently provided elsewhere (OTP referenced Commission Docket 01-1023). DOC DER noted again, that in lieu of removing the requirement, the Commission's addition of the provision regarding cost-prohibitive or unavailable information should alleviate OTP's concern and DOC DER does not recommend modifying this requirement.[9] Additionally, the DOC DER noted that for any items that may be reported in another docket, it would be reasonable to mirror language to the extent reasonable, but not remove the items; the information could either be provided or simply referenced.

[7] OTP Initial, pg. 8
[8] DOC DER pg. 3-4
[9] DOC DER pg. 3-4

30	Staff Response:	Staff has modified the requirement in include the clarity sought (regarding the costs broken down by categories) but has kept the item in the filing requirements consistent with DOC DER's recommendation and reasoning. Staff Clarified Language: 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.) Staff believes that the data sought needs clarification. The information requested relates to utility costs to the customer or DER developer for interconnection; including, facility, distribution and network upgrades borne by the customer or developer. Information requested in the -10 reports to-date has been installation costs without incentives and final interconnection costs paid to the utility. Reforms to the -10 reports will remove the final interconnection costs paid to the utility which is the data sought in this filing requirement. The updated Minnesota DER Interconnection Process (Docket No. E999/CI-16-521) includes temporary annual reporting of the variance between cost estimates and actual costs of upgrades for 20kW and larger DER.
31	3.A.17	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year
32	Comments by Stakeholders:	*OTP and DOC DER comments same as above (3.A.16).*
33	Staff Response:	*Staff comments same as above (3.A.16).* Staff Clarified Language: 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.)
34	3.A.18	Total number of DER generation systems which completed interconnection to the system in the prior year
35	Comments by Stakeholders:	*OTP and DOC DER comments same as above (3.A.16).*
36	Staff Response:	*Staff comments same as above (3.A.16).* Staff Clarified Language: 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.)
37	3.A.19-3.A.25	***NEW REQUIREMENTS AS PROPOSED BY THE DOC DER***

38	Comments by Stakeholders:	DOC DER supported the addition of the additional sub-item reporting requirements as the items would ensure that distribution system advancements are being tracked and considered.[10]
39	Staff Response:	Staff has included these sub-items as information that would be useful to track, to the extent they are not reported elsewhere or are not cost-prohibitive, time-intensive, or unavailable to a utility. Staff acknowledges differing comments from utilities about the difficult nature of obtaining and filing some of this data – and that estimates may be needed – and that should suffice. Staff believes general estimates of this information would be useful to understand changes on the distribution system and inform the Commission on how aware (or not) a utility is or can be regarding system additions or impacts. For utilities where this information is required elsewhere, reference to that data is sufficient.
40	3.A.19	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
41	3.A.20	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
42	Comments by Stakeholders:	DEA noted that this information will be available online with the new DG interconnection requirements and will be updated at least monthly in a public interconnection queue.
43	Staff Response:	Staff is seeking this information in the interim, not all utiltiies will need to report this data in a public interconnection queue reporting requirements, for those that do – reference to those reports will be sufficient.
44	3.A.21	Total number of electric vehicles in service territory.
45	3.A.22	Total number and capacity of public electric vehicle charging stations.
46	3.A.23	Number of units and MW/MWh ratings of battery storage.
47	Comments by Stakeholders:	DEA noted concerns about the inclusion of this item and that it believes it was a subset of A.19 and was therefore unnecessary. DEA noted it could only report on storage systems that have applied for interconnection.
48	Staff Response:	Staff agrees that DEA should only provide storage on its system that it is aware of or has available data. Staff believes the item should remain as it asked for the MW/MWh ratings of storage on DEA's system (which is not explicitly called out in A.19) – but again, staff notes, it would be to the extent the information is reasonably available to DEA (or for any utility).
49	3.A.24	MWh savings and peak demand reductions from energy efficiency program spending in the previous year.
50	3.A.25	Amount of controllable demand (in both MW and as a percentage of system peak).
51	Comments by Stakeholders:	DEA noted it would benefit from additional clarity on this item. Questions posed by DEA: 1) What parameters or method is sought to determine this number? 2) What peak does the question refer to? 3) Should the largest utilized demand reduction be provided or the system potential?[11]

[10] DOC DER Initial, pg. 9
[11] DEA Reply, pg. 5

52	Staff Response:	Staff is seeking this information to better understand the amount of controllable demand available to utilities. Consistent with DEA's questions and comments on this item, due to the many variables associated with this question, staff first asks that any assumptions and information provided has sufficient detail to understand the qualifications and assumption inherent in the data. Staff requests that utilities provide information in the format most available and reasonable (with sufficient supporting information to understand the information provided), however, to the extent practicable, staff is seeking: the demand response system potential - the amount of controllable demand provided using a range (to bookend controllable demand to the utility based on external factors and factors considered), should be the maximum demonstrated demand reduction (assumption that all load running), and the estimated utility (MP/OTP/DEA) system coincident peak should be used assuming the load control was not operating.

53	Financial Data		
54	3.A.19		Historical distribution system spending for the past 5-years, in each category:
55		a.	Age-Related Replacements and Asset Renewal
56		b.	System Expansion or Upgrades for Capacity
57		c.	System Expansion or Upgrades for Reliability and Power Quality
58		d.	New Customer Projects and New Revenue
59		e.	Grid Modernization and Pilot Projects
60		f.	Government Mandates
61		g.	Metering
62		h.	Other
63	Comments by Stakeholders:		Each utility either provided their own historical spending categories, or indicated that the list as proposed by staff was reasonable. DOC DER noted that authorizing historical itemization of distribution system costs was reasonable, but supported requiring future tracking of distribution costs in the categories proposed by staff.[12] Minnesota Power supports the financial categories.[13] Otter Tail Power assumes reporting is only capital spends and proposes replacing the categories with: new load and reliability, replace, relocate, metering, grid modernization and pilot projects; further, asks Commission to provide examples of grid modernization and pilot projects unless intended to leave that decision to each utility.[14]

[12] DOC Initial, pg. 9-10
[13] MP Initial, pg. 3
[14] OTP Initial, p. 7

		Dakota Electric requested it be able to report in the following categories which are similar to the staff proposed categories (but clarified/further defined): age-related replacements and asset renewal, system capacity expansion (capacity driven), system capacity expansion (reliability driven), projects to support new members (including metering, transformers and wires), system projects driven by governmental projects (road moves), grid modernization (advanced technologies).[15] DEA found metering as a stand-alone category was not appropriate as metering is part of many other projects that would fit under other categories.
64	Staff Response:	Staff has updated the historical spend categories consistent with the utility information (individually in each of their filing requirement drafts) attached to the briefing paper but has left future categories as-is. While staff has not modified the categories as DEA had requested (removal of a sub-item regarding metering) – staff believes DEA's arguments were reasonable and DEA should provide information as it deems fit within best within each categories. As long as the information provided by each utility is consistent year to year trends can be gleaned. Additionally, staff provided two administrative corrections to this item to include an 'and' that was missing and to modify item 'f' to provide additional clarity to its meaning (local requirements only and not larger policy mandates).
65	NEW	All non-utility 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).
66	Comments by Stakeholders:	DOC DER recommended in each of the three dockets, that this requirement be added as it would help to understand the upgrades that customers have financed as a condition of interconnection as a way to identify gird constraints that could be more proactively identified and met through a planning process.[16] DEA noted that this information could encompass costs as broad as governmental entity payment for road relocations, or system upgrades that include contributions from others. DEA noted it does not currently track those numbers (in this context). However, DEA questioned that if this item was seeking *only* information regarding DG interconnection upgrade costs, it was similar to A.16 and should be removed.[17]
67	Staff Response:	Staff has included this item as a filing requirement. Staff understands that some commenters noted that their utility currently does not track this information. To the extent it could be tracked on a going forward basis, it would be useful, but each utility would need to assess the cost of doing so and report back to the Commission if it finds it is unreasonable to do so. Staff also notes that it is different from A.16. in that is requires a breakdown by subset (project type) and location.
68	3.A.20	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects

[15] DEA Initial, p. 8.
[16] DOC Initial, pg. 11
[17] DEA Reply, pg. 5

69	3.A.21	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
70	Comments by Stakeholders:	DOC DER recommended that this item be consistent with the cost categories in an earlier sub-item.[18] OTP recommended that this requirement only pertain to capital project investments which exceed $250,000 as that is the threshold in which projects require internal project review.[19] The DOC DER noted that it did not have sufficient information to determine the reasonableness of this request and threshold. The DOC DER recommended that OTP utilize the cost-prohibitive or unavailable information provision that it recommended be added.[20]
71	Staff Response:	Staff again agrees with the assessment of the DOC DER regarding information that may be cost-prohibitive to provide, therefore staff has not modified this item. Additionally, staff has made an administrative clarification and has incorporated the expanded itemized list (in lieu of the reference).
72	3.A.22	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

73	DER Deployment	
74	3.A.23	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.)

[18] DOC DER Initial, pg. 9-10
[19] OTP Initial, at 7
[20] DOC DER Reply, at 5

75	Comments by Stakeholders:	OTP and DOC DER comments same as above (3.A.16).
76	Staff Response:	Staff comments same as above (3.A.16).
77	3.A.24	Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.
78	3.A.25	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

SECTION 3B. Preliminary Hosting Capacity Data

79	3.B.1	Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)
80	Comments by Stakeholders:	**DEA**: Data Requirements: Dakota Electric requests that the minimum load be supplied by substation and not by feeder since members do not know which feeder they are connected to and the feeder which a member is supplied by could be changed without notice. Dakota also noted that the ability to interconnect DER to its system is limited by the back feeding of the distribution system, through the substation to the transmission, generally this is not limited by the minimum load of a feeder. Allowing Dakota Electric to provide minimum loads by substation greatly reduces the manual effort required to provide this information.[21] The OAG noted that additional inquiry into DEA's claims about not providing feeder level data may be reasonable. OAG argued that feeder level data could provide insight into parts of DEA's system.[22] The OAG requested that the Commission seek additional clarity from DEA (before the November 2019 filing) on the level of difficulty in obtaining this data as well as to better understand DEA's position. Heading Name: DEA requested that the heading be modified to clarify that the data provided is not hosting capacity information as to not confuse persons reviewing the information. DEA argued that much more than minimum daytime load factors into a system ability to support additional DERs, and therefore, this heading may be confusing to persons reviewing the data.[23] The DOC DER did not agree with DEA's proposed modification and suggested that the heading name be left, as-is, and that DEA can provide clarifying information in what is filed to better reflect the usefulness of the data.[24]

[21] DEA Initial, pg. 9
[22] OAG Reply DEA, pg. 2
[23] DEA Initial, pg. 9-10
[24] DOC DER Reply DEA, pg. 3-4

		MP: MP noted that it would prefer to provide a single, annual daytime minimum load (as the driver for system design).[25] DOC DER noted that more granular information is preferable, it is cognizant of time-consuming or resource intensive requests. Therefore, the DOC DER noted that it found MP's position a reasonable starting point but requested that MP work to improve upon their capability to obtain more granular data in the future.[26] OAG responded to MPs request and noted that MP would have more than a year to provide this information and should better explain why the cost of obtaining the data outweighs the value. OAG does not believe the information offered by MP is sufficient to fulfill this requirement and asks that the Commission not modify the filing requirement.[27]
81	Staff Response:	Staff concurs with both the interpretations and asks of MP and DEA. Staff understands that hosting capacity analysis involves more than daytime minimum load or peak load data for a feeder or a substation, and some information may be time-consuming to obtain versus the value obtained by stakeholders who would review this data. Therefore, while the filing requirement language has not been modified by staff, the information provided by the utilities is useful context for what is reasonably available on their system and would receive staff support upon filing of such information. Staff simply requests that each utility provided sufficient information in their filing on what is reasonably available system information and any constraints the utility may have in provided additional or more detailed data. Consistent with the OAG recommendation, staff requests that DEA provide additional detail in its 2019 IDP regarding the concerns of the OAG and how more granular information could be obtained. Staff has not proposed an additional comment period between now and November 2019, however that is a reasonable option that could be pursued. Additionally, staff *has* modified the heading of this section (to "Preliminary Hosting Capacity Data / <u>Minimum Substation Load Data</u>") for all three utilities to reflect the concern of DEA, which would apply to all utilities required to provide minimum substation load data. Staff believes that while much more analysis goes into a hosting capacity analysis, this data is attempting to be the precursor (or preliminary) step to that analysis. Staff believes with the word 'preliminary' combined with the addition of 'Min. Substation Load Data', in conjunction with any disclaimers or information filed by each utility in their response/IDP, should suffice to not confuse persons reviewing the data.

SECTION 3C. Distributed Energy Resource Scenario Analysis

[25] MP Initial, pg. 2
[26] DOC DER Reply MP, pg. 3
[27] OAG MP Reply, pg. 1

82	3.C.1	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.
83	Comments by Stakeholders:	1. MP sought clarity on what types of DER should be included for this item.[28] DOC DER noted that the draft IDP requirements (for all utilities) provided the definition of DER for the purposes of the filing requirements on page 1, OAG-RUD[29] believed this definition should be sufficient for filing requirement clarity and recommended that no further definition of DER be provided in order to avoid confusion.[30] 2. OTP requested that it be relieved of the requirement to file three scenarios, and instead requested that it only file a base case and a high scenario. OTP provided detailed information on its projected DER penetration, and why it believes that multiple scenarios are not necessary for its likely DER futures.[31] DOC DER responded that if the Commission included the provision which allows OTP to explain why it would be unreasonable or cost-prohibitive to provide the information, which should be a sufficient avenue for OTP to make their arguments at that time. The DOC DER supported keeping the requirement in the filing requirements.[32] 3. DEA proposes to focus on customer-owned renewables, not demand response or energy efficiency. DEA noted its concern about the intensity of this requirement, its usefulness, and looking to ensure value to its members.[33] DOC DER used a similar reasoning to OTP's concerns (for cost-prohibitive information) to address DEA's concerns.[34]
84	Staff Response:	1. MP: Staff agrees with the OAG-RUD and has not provided additional information beyond the definition of a DER in the filing requirements. 2. OTP: Staff agrees with the DOC DER, that as proposed, with the provision which allows OTP to not provide information that is either unavailable for cost-prohibitive, that should resolve OTPs concern. Therefore, staff has not modified the filing requirement. 3. DEA: Staff requests DEA consider whether coop-owned renewables and electric vehicles should also be included in the scenario analysis. Staff has not modified the filing requirement consistent with the DOC DER recommendation and reasoning.
85	3.C.2	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both

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[28] MP Initial, pg. 3
[29] OAG MP reply, pg. 1
[30] DOC DER Reply MP, pg. 2
[31] OTP Initial, pg. 2
[32] DOC DER Initial, pg. 6 of 18-253
[33] DEA Initial, pg. 4, 10
[34] DOC DER Reply, pg. 4

		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.
86	3.C.3	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration ~~adoption~~, 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.
87	Staff Response:	Staff has modified this requirement, as noted above, to clarify the intent of the item.
88	3.C.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)
89	Comments by Stakeholders:	MP argued that this requirement was not applicable to an annual or biennial reporting process as it is a process being implemented at MISO. MP noted that assessment of this nature (with or without FERC orders) would be purely theoretical.[35] DOC DER noted that "a key design element of the IDP requirements is their adaptability to an evolving technological and regulatory paradigm. …Future iterations of the IDP requirements are likely to address the relevance of this requirement, and it remains a possibility that it will be modified or removed as appropriate in the future." DOC DER concluded that inclusion of this requirement was reasonable at this time and recommended it not be removed.[36]
90	Staff Response:	Staff has left this item in the filling requirements, staff is not seeking a in depth modeling or scenario planning exercise, and instead is seeking a narrative discussion on how each utility is planning or envisioning impacts to its system based on these existing or forthcoming FERC orders. It will be useful for the Commission to better understand how Minnesota utilities are adapting to FERC rulings, and potentially aggregations, on and within their systems.

[35] MP Initial, pg. 3
[36] DOC DER, MP Reply at 4

SECTION 3D. Long-Term Distribution System Modernization and Infrastructure Investment Plan

91	3.D.1	Xcel shall provide a 5-year Action Plan as part of a 15-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.
92	Staff Comment:	As noted in the briefing paper, consistent with stakeholder and all utility comments, staff has modified each utility's filing requirements to consider a 10-year long-term plan (in lieu of a 15-year term).
93	3.D.2	Xcel shall provide a 5-year Action Plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis as appropriate. 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 above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:
94	Stakeholder Comments:	DEA noted that it intended to provide its plans to modernize its distribution system, but it was not staffed to provide a complete financial analysis with the detail requested below (NPV, per customer costs, etc.) DEA also noted uncertainty about what project would constitute a modernization project – and in relation to Section E – whether its existing AGi project would be considered a non-wire/non-traditional or modernization project.
95	Staff Comment:	Staff notes that any complex financial analysis that would be too burdensome or costly to obtain would qualify for the additional provision on cost-prohibitive information. Staff would categorize DEA's AGi project both as a modernization project as well as a non-traditional/non-wires solution. Minn. Statute offers some clarity of a modernization project in Minn. Stat. 216B.2425: *"…modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies."*[37] Also, the MN PUC Staff Report on Grid Modernization provides some additional guidance: *"…assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network."*[38]

[37] Minn. Stat. 216B.2425
[38] MN PUC Staff Report on Grid Modernization, Commission Docket 15-556

		Staff has made minor administrative modifications to this item (removed reference to other sub-items and corrected typos).
96	3.D.2 (i)	Overview of investment plan: scope, timing, and cost recovery mechanism
97	3.D.2 (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]
98	3.D.2 (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.
99	3.D.2 (iv)	System interoperability and communications strategy
100	3.D.2 (v)	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)
101	3.D.2 (vi)	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
102	3.D.2 (vii)	Customer anticipated benefit and cost
103	3.D.2 (viii)	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
104	3.D.2 (ix)	Plans to manage rate or bill impacts, if any
105	3.D.2 (x)	Impacts to net present value of system costs (in NPV RR/MWh or MW)
106	Comments by Stakeholders:	DOC DER suggested the additional sub-item: <u>For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis.</u>[39] The Department believes these two sub-items will both hold utilities accountable for any potential grid modernization projects and require them to quantify costs and benefits, which further protects ratepayers from imprudent investments. CUB and FE also supported this additional sub-item. DEA noted that this request may not align with its internal budget planning process, cost-benefit analysis may not be available this far in advance. DEA also questioned whether the cost-benefit analysis would be set at a $5 million dollar threshold or a $2 million dollar threshold (which DOC, and other stakeholders, advocate here for analysis of

[39] DOC DER Initial, pg. 12

		alternatives in Section E).[40] However, DEA noted that if this was to apply for investments similar to its AGi proposal, then it had already conducted that analysis.
107	Staff Comment:	Staff agrees with the DOC DER and has modified this sub-item for each utility. Staff believes that a cost-benefit analysis should be provided to the extent one is available or is reasonably obtainable during the reporting period for a project. The intent of this sub-item is to ensure that the Commission is aware and informed in a manner that is either a pre-cursor to a utility recovery request, or offers a better understanding the Commission on how differing grid modernization investments fit together in a utility modernization plan. Which would include some level of cost benefit analysis early on what the utility envisions the costs and benefits of a future proposal may be.
108	Comments by Stakeholders:	DOC DER suggested the additional sub-item: <u>Status of any existing pilots or potential new opportunities for grid modernization pilots.</u> The Department believes these two sub-items will both hold utilities accountable for any potential grid modernization projects and require them to quantify costs and benefits, which further protects ratepayers from imprudent investments.
109	Staff Comment:	Staff agrees with the DOC DER and has modified this sub-item for each utility.
110	3.D.3	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 15 years. The 15-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 Xcel is currently using.

SECTION 3E. Non-Wires (Non-Traditional) Alternatives Analysis

111	3.E.1	OTP/MP/DEA shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the filing year, which cost five million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

[40] DEA Reply, pg. 5

112	Comments by Stakeholders:	DOC DER made several recommendations in relation to this item: 1. the DOC DER recommended a change to the heading, consistent with the approval Xcel IDP filing requirements (to add 'non-traditional'); 2. For all three utilities, a reduction of the cost threshold from $5 million to $2 million. The DOC DER noted that the $5 million was unlikely to trigger projects for review, if any, for utilities, and in order to ensure the likelihood of a project being evaluated, it was reasonable to reduce the threshold.[41]
113	Staff Comment:	Staff has not modified this item and left the threshold at $5 million. However, staff notes that the threshold for review is high, is likely to not trigger a NWA review of a project and the Commission may want to lower the threshold for this planning cycle. Further discussion with utilities and stakeholders at the December 6 agenda meeting may be useful.
114	3.E.2	OTP/MP/DEA shall provide information on the following:
115	3.E.2 (I)	Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
116	3.E.2 (ii)	A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
117	3.E.2 (iii)	Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
118	NEW – (3.E.2 (iv))	3.E.2 (iv) - A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.
119	Comments by Stakeholders:	DOC DER supported the inclusion of a new requirement (originally proposed by Commission Staff in Xcel's IDP) for all utilities to ensure that non-wires/traditional alternatives are being screened in the early stages of a distribution system project, this addition is consistent with an addition proposed by Commission staff in the Xcel IDP docket. [42]
120	Staff Comment:	Staff agrees with the DOC DER and its reasoning, that this sub-item would be a good additional to all utilities IDP filings and has modified each of the requirements to include this sub-item.

[41] DOC Initial, pg. 12-13
[42] DOC Initial, pg. 13

Briefing Paper – Attachment B

Date: December 6, 2018

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

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 ~~15~~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

~~18.~~25. Amount of controllable demand (in both MW and as a percentage of system peak)

Financial Data

~~19.~~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 ~~Government Mandates~~
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).

~~20.~~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 ~~(e.g. see list in 19.)~~, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:

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

~~21.~~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

~~22.~~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.)

~~23.~~32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.

~~24.~~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 ~~adoption~~integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

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 ~~15~~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 ~~analysis~~scenarios, hosting capacity analysis/daytime minimum load data, and non-wires alternatives analysis.

~~1.~~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

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

investments planned for the next 5-years (expanding on topics and categories listed ~~A19 and A20,~~ above). Otter Tail 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 ~~(e.g. IVVO vs. FLISR)~~. 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

~~2.~~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 ~~15~~ 10 years. The ~~15~~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

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

1. Otter Tail shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the filing year, which cost five 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.

Date: December 6, 2018

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

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 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.

For filing requirements which Minnesota Power claims is not yet practicable or is currently cost-prohibitive to provide, Minnesota 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 Minnesota Power to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the ~~15~~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):** 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)

[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 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).
20. 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.)
21. 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.)
22. 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.)
23. 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.)
24. 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.)

25. Total number of electric vehicles in service territory

Financial Data

~~18.~~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.) ~~Government Mandates~~
   ~~g.~~f. 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).

~~19.~~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 ~~(e.g. see list in 19)~~, 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

~~20.~~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

~~21.~~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.)

~~22.~~32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.

~~23.~~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 ~~adoption~~integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

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 ~~15~~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 ~~analysis~~

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

scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis~~as appropriate~~. 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 A19 and A20~~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]
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. ~~(e.g. IVVO vs. FLISR).~~ 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, Dakota Electric 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 ~~15~~ 10 years. The ~~15~~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.

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

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 5 years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the filing year, which cost five 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

Briefing Paper – Attachment D

Date: December 6, 2018

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

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 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 ~~15~~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)

[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

~~18.~~26. Historical distribution system spending for the past 5-years, in each category:
   a. Age-Related Replacements and Asset Renewal
   b. System Expansion or Upgrades for Capacity
   c. System Expansion or Upgrades for Reliability and Power Quality
   d. New Customer Projects and New Revenue
   e. Grid Modernization and Pilot Projects
   f. ~~Government Mandates~~ Projects related to local (or other) government-requirements (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).

~~19.~~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 ~~(e.g. see list in 19)~~, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include:

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

~~20.~~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

~~21.~~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.)

~~22.~~32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration

~~23.~~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 ~~adoption~~integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

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 ~~15~~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 ~~analysis~~ scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis.~~as appropriate.~~ The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system

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

investments planned for the next 5-years (topics and categories listed~~expanding on A19 and A20,~~ 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~~(e.g. IVVO vs. FLISR)~~. 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 ~~15~~ 10 years. The ~~15~~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 5 years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the filing year, which cost five 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.