MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	April 19, 2018	Agenda Item 6-9**

Company	Dakota Electric, Minnesota Power, Otter Tail Power, Xcel Energy
Docket No.	**E999/CI-15-556** **E002/CI-18-251, E017/CI-18-253, E015/CI-18-254, E111/CI-18-255** **In the Matter of the Commission Investigation on Grid Modernization (15-556)** **In the Matter of Distribution System Planning for Dakota Electric (18-255)** **In the Matter of Distribution System Planning for Minnesota Power (18-254)** **In the Matter of Distribution System Planning for Otter Tail Power (18-253)** **In the Matter of Distribution System Planning for Xcel Energy (18-251)**
Issues	What action should the Commission take on distribution system planning for each of the following rate-regulated utilities? Should the Commission authorize staff to release the draft proposals for comment?
Staff	Tricia DeBleeckere Tricia.DeBleeckere@state.mn.us 651-201-2254 Michelle Rosier Michelle.Rosier@state.mn.us 651-201-2212

✓ **Relevant Documents**	**Date**
Commission - Notice of Comment Period on Distribution System Planning Efforts and Considerations	April 21, 2017
Xcel Energy – Response to A and B	June 21, 2017
Dakota Electric – Comments (A and B)	June 21, 2017
Otter Tail Power – Comments (A and B)	June 21, 2017

To request this document in another format such as large print or audio, call 651.296.0406 (voice). Persons with a hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

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

✓ **Relevant Documents**	**Date**
Great River Energy – Comments (A and B)	June 21, 2017
Minnesota Rural Energy Agency - Comments (A and B)	June 21, 2017
Minnesota Power – Comments (A and B)	June 29, 2017
Advanced Energy Economy – Comments (Initial C)	July 20, 2017
Dakota Electric – Comments (Initial C)	July 20, 2017
Energy Storage Association – Comments (Initial C)	July 21, 2017
Alevo USA – Comments (Initial C)	July 21, 2017
Otter Tail Power – Comments (Initial C)	July 21, 2017
Xcel Energy – Comments (Initial C)	July 21, 2017
Minnesota Power – Comments (Initial C)	August 21, 2017
Citizens Utility Board – Comments (Initial C)	August 21, 2017
DOC DER – Comments (Initial C)	August 21, 2017
Interstate Renewable Energy Council – Comments (Initial C)	August 21, 2017
Fresh Energy – Comments (Initial C)	August 21, 2017
Fresh Energy – Comments (Reply C)	September 21, 2017
Xcel Energy – Comments (Reply C)	September 21, 2017
Interstate Renewable Energy Council – Comments (Reply C)	September 21, 2017
Minnesota Power – Comments (Reply C)	September 21, 2017
Citizens Utility Board of Minnesota – Comments (Reply C)	September 21, 2017
Commission – January 23, 2018 Planning Meeting Slides	January 31, 2018

Contents

I. Statement of the Issues

What action should the Commission take on distribution system planning for each of the rate-regulated utilities: Dakota Electric, Minnesota Power, Otter Tail Power, and Xcel Energy? Should the Commission authorize staff to release the draft proposals for comment?

II. Overview

Through a lengthy and comprehensive stakeholder process (outlined in the Background section, below), the Commission has solicited input and explored many topic areas and aspects of grid modernization and distribution system planning. Through this process, as well as through more recent (and rapid) utility filings for recovery of grid modernization costs (rate cases, riders, and miscellaneous filings), it has become apparent that thorough and transparent distribution system planning processes are necessary. It is anticipated that continued and significant investment in distribution systems by our rate-regulated utilities will continue. These investments are occurring in order to implement new technology, adapt to increases in DER, allow increased communications in technology infrastructure, and adapt to different participation methods in wholesale and retail markets.

Additionally, through the Commission's April 21, 2017 utility and stakeholder questionnaire (2017 DSP Questionnaire), it has become clear that a one-size-fits-all approach to distribution system planning for all Minnesota utilities would not be effective, as each utility's system, size, geographic location, customer-base, existing investments (technology and distributed energy resource (DER) deployment), and long-term business plans vary. Staff believes that each utility's Commission-directed distribution system planning process or filing requirements will both, initially need to be different in scope, as well as have the flexibility to change over time.

With that future in mind, the Commission is seeking to proactively evaluate the need, cost, and benefits of these distribution system investments in a more transparent, comprehensive, and stakeholder-driven forum, rather than on an isolated basis in a utility rate case (or other recovery docket). This will put the Commission in the position of having a better general understanding of the role new distribution system technology will play in the future, how that technology operates, what the full cost and functionalities may be, and limitations of the technology are when evaluating a specific utility's distribution system investment. This approach will help to ensure distribution system investments are being made with appropriate ratepayer protections, cost effectiveness, security, reliability, and resilience as priorities.

III. Background: Commission Investigation into Grid Modernization: Focus on Distribution System Planning

The Commission has been actively involved in investigating ways it can support the modernization of Minnesota's grid infrastructure. This section details the notable actions and milestones.

The Commission initiated the Commission's Grid Modernization investigation in May 2015, acknowledging the following:

- The grid is at a strategic inflection point, a time of significant change.
- Changing customer demands, new technologies, and evolving public policy will drive increased deployment of distributed resources.
- Tomorrow's integrated electric grid will be more distributed and flexible, will optimize and extract value through the grid, will operate resiliently against natural disaster and attacks, and will be cleaner, reliable, and affordable.
- Development of tomorrow's grid is already underway; there is an unprecedented opportunity to invest in a 21st century grid.
- Updates to distribution planning process will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; should be coordinated with resource and transmission planning; and could incorporate stakeholder informed planning scenarios.

Figure 1. MN Commission Grid Modernization Image

Through 2015, the Commission held a series of workshops seeking input on the following questions from utilities and stakeholders:

- What policy objectives are important when considering modernization of Minnesota's electric distribution systems?
- What customer behaviors and preferences (current and emerging) are important when considering modernization of Minnesota's electric distribution systems?
- What qualities and outcomes should Minnesota's electric distribution systems have in order to achieve those policy objectives and support those customer preferences?
- What specific national examples of grid modernization and emerging best practices could inform Minnesota's discussion of electric distribution system modernization?

In March 2016, the Commission released the *Staff Report on Grid Modernization* (2016 Staff Report). 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, the Commission supported distribution system planning as the most reasonable and actionable way for the Commission to assist in the forthcoming grid evolutions. The Commission agreed with the creation of a comprehensive, coordinated, transparent, and integrated distribution system planning process in Minnesota and agreed with the staff proposed principles to guide further work[1]:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies.
- Enable greater customer engagement, empowerment, and options for energy services.

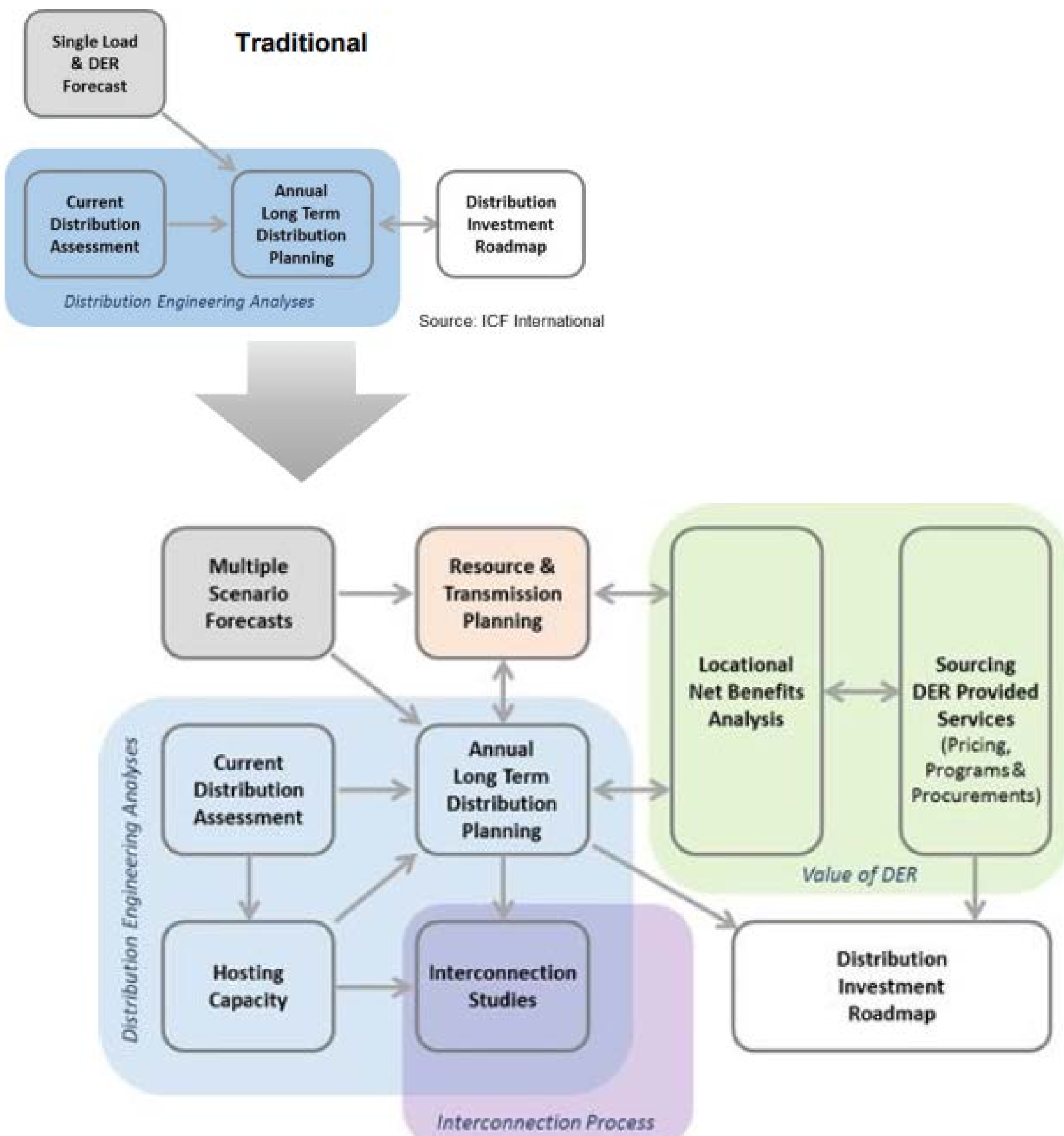
---

[1] MN PUC Staff Report on Grid Modernization, March 2016

- 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. The report outlined considerations the Commission could make when establishing a distribution system planning process. [2][3]

Figure 2. Traditional Planning Framework and Proposed MN Integrated Planning Framework



[2] Integrated Distribution Planning Report, August 2016 (ICF Report)

[3] MN PUC Grid Modernization: Distribution Planning Workshop Slides, Oct. 24, 2016

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.

In April 2017, the Commission issued a lengthy 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. All comments are included as relevant documents to this briefing paper and are summarized below.

Today, staff has reviewed all party comments and proposes draft integrated distribution plans (IDP or MN-IDP) filing requirements and processes for each of the four rate-regulated utilities: Dakota Electric Association (DEA), Minnesota Power (MP), Otter Tail Power (OTP), and Xcel Energy (Xcel); those draft proposals are attached to this briefing paper as Attachments A-D.

Staff is requesting the Commission review the proposed MN-IDP filing and process requirements and authorize staff to release the documents for utility and stakeholder comment. While many components of the draft frameworks are similar, staff expects annual or biennial iterations of these requirements will further morph and conform to each utility, as needed. The proposed MN-IDPs for each utility have different filing frequency (annually or biennially) but all require both a five-year action plan and a long-term, 15-year outlook, with each filing.

Staff proposes the following non-binding schedule for next steps in these dockets:

- April 19, 2018 - Commission decision on release of draft IDP requirements for comment
- May 19, 2018 – Commission release of notice of comment (if authorized on April 19)
- Early June 2018 – Initial Comments Due (Proposed scenarios due from Xcel and DEA[4])
- Late June 2018 – Reply Comments Due
- July/August 2018 – Commission consideration of comments and revised plans
- November 1, 2018 – Proposed filings due from Xcel and DEA
- November 1, 2019 – Proposed filings due from OTP and MP

Last, staff wants to clarify that each utility's MN-IDP is not intending to replace, hinder, or approve a utility's own internal annual distribution system capital budgeting and planning processes; nor is Commission review or approval a prudency determination. What the Commission is attempting to do here serves a different function; it is attempting to ensure the Commission, utilities, and stakeholder all have a broader understanding and input into considerations a utility uses when planning the distribution system.

[4] Discussed in more detail below.

IV. Utility Comments: Current Utility Distribution Systems Planning and Processes (Part A&B)

Comments on utility distribution system planning were received by DEA, Great River Energy (GRE), Minnesota Rural Electric Association (MREA), OTP and Xcel. MREA and GRE, as electric power cooperatives, provided more general comments about specific grid modernization programs or technologies available to their members.

Most utilities (in even their initial comments on their planning processes) expressed the need for flexible approaches to any Commissioner-led distribution system planning. Many utilities argued that each system is unique and due to the dynamic nature of the distribution system, rigid processes would not accommodate the utility's need to maintain reliability. Generally, the utilities acknowledged that the grid is changing, that modernization is an important priority, and that integration of DER will be a part of the modernization efforts. However, flexibility, professional judgment, and the unique circumstances of the individual utilities argue against a prescriptive regulatory approach.

Another common theme was the preference to encourage information sharing between utilities on grid modernization efforts. There was general support for improved interconnection capabilities and hosting capacity analysis; and the importance of accommodating increased DER was acknowledged. Additionally, the potential value of DER was discussed, especially demand response, in reducing peak loads across systems.

As discussed further below, to date, the utilities have found little to no value in DER as a solution to a specific system constraint. Importantly, DERs are *not* considered in distribution planning processes by any Minnesota utilities today. The operating characteristics of DERs are seen as so different from traditional distribution infrastructure that DER cannot provide the reliability and longevity that is needed in distribution planning.

Similarities and differences between our Minnesota utilities planning characteristics were summarized in slides from the January 23, 2018 Planning Meeting.[5]

Figure 3. Summary of Minnesota Utility Systems

Utility Differences:
- Various stages of grid modernization;
- Degrees of implemented technology and how used;
- Levels of DER-interconnection requests and DER-penetration levels;
- Distribution system spend by year (factor of 10);
- Geographic region and density;
- Occurrences of (and need for) special distribution projects or studies; and,
- Age of existing infrastructure.

[5] Commission Docket CI-15-556, Slides from January 23, 2018 Planning Meeting

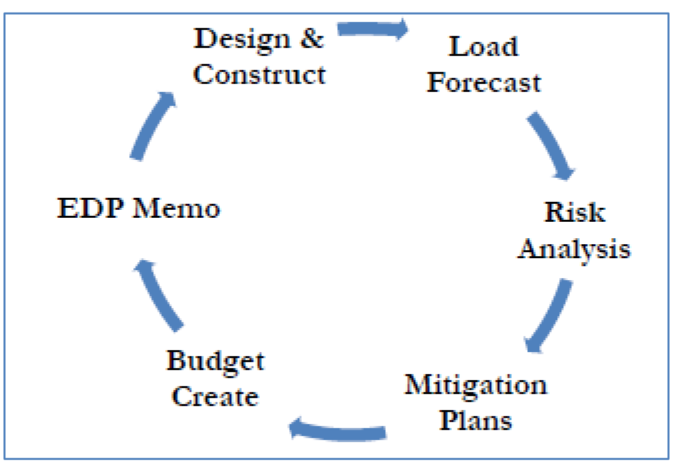
Utility Similarities:
- Annual distribution system capital budgets;
- Metrics for planning;
- Low load growth and DER penetration;
- Varied system visibility even within distribution systems;
- Limited distribution engineering staff;
- Limited connection between DSP and IRP/Transmission Planning; and,
- DER treatment in forecasts (short term energy vs. long term capacity).

The utility descriptions on how they plan their distribution system were generally similar to each other and were consistent with traditional distribution planning methods utilized by the industry. Historically, distribution utilities have followed the same general distribution system planning process which includes (up to) three internal plan types: (1) annual capital budget plans, (2) targeted or periodic plans, and (3) long-term plans.

A. Annual Distribution Plans

Annual distribution system plans are created by assessing the load forecast down to the individual substation or feeder. The annual distribution system plans are conducted to support annual capital construction budgets (typical distribution system improvements, replacements, extensions, etc.) The utility runs models based on anticipated load growth, planned new (targeted) load additions, or other changes to determine if a system reliability or overloading issues (N-0 or N-1 contingency events) are experienced during peak load conditions (and therefore, an system upgrade or modification is necessary). The projects resulting from the annual distribution system model are then ranked and the year's required capital projects are planned. All utilities indicated that DER solutions have not traditionally been considered as viable alternatives for resolving distribution capacity issues due to cost, reliability, longevity, and dispatachability. Xcel noted that it believes those constraints are lessening "as the technologies mature and operational experience increases."[6]

Figure 4. Xcel's Annual Distribution Planning Process



[6] Xcel Comments – Initial AB, page 30.

B. Targeted or Periodic Plans

Targeted or periodic plans are conducted by most all utilities. These are studies or models completed, as necessary, to support new or large loads that (for one reason or another) were not anticipated during the annual distribution system plan process. DEA noted these largely occur on their system due to city or county road scope or design changes. DEA also stressed that due to the short timeframe DEA has to respond to these system design changes, flexibility is needed in any planning process to ensure DEA can meets its obligations to serve its customers.[7]

C. Long-Term Plans

Long-term or long-range plans are completed on various time scales dependent on the utility, some conduct long-term studies on an as-needed basis, others, like Xcel, continue to evolve a longer-term planning horizon. Xcel indicated its evaluation process for long term assessments includes energy efficiency and demand side management.[8] Xcel included in its comments two focused long-term area studies as attachments.[9] All distribution system plan types may ultimately inform bulk transmission projects by each utility, as needed.

V. Areas for Consideration and Party Comments (Part C)

Comments were received from Advanced Energy Economy (AEE), Alevo Citizen's Utility Board (CUB), DEA, Department of Commerce (DOC), Energy Storage Alliance (ESA), Fresh Energy, Interstate Renewable Energy Council (IREC), MP, OTP, and Xcel.

A. DSP review type and conformance with other MN process

1. Approach to Distribution System Planning (Advanced Planning Thresholds) and Timing

Many commenters argue for the standard walk-jog-run or other phased approaches to modernizing Minnesota's distribution system and most all agreed that advancement between any phased approaches would largely differ in scope and speed.

IREC noted that not all parties agree on how to characterize the respective stages, where utilities are situated with respect to the three stages, and how quickly the utilities should advance through them. IREC's concern was that this multi-stage approach could improperly defer improvements to planning processes and tools that are feasible and appropriate to pursue in the nearer term. AEE supported requiring all utilities to begin some level of a planning process now, supported an iterative approach to planning that aligned with the pace of industry and system changes (such as rates of DER adoption and evolving customer needs) and suggested the

[7] DEA Comments Initial AB, page 5.

[8] Xcel Comments Initial AB, page 31.

[9] The targeted area studies were for the Hiawatha High Voltage Transmission Line (HVTL) and the Hollydale HVTL; both were projects which were required by Minnesota legislature to undergo further analysis due to public opposition.

Commission assign dedicated staff to this work. However, IREC noted that - if - a walk-jog-run or similar approach is adopted, the Commission should carefully explore and define, with stakeholder input, the characterization of each stage and timelines for advancing through them, with the overriding goal of ensuring proactive planning for increased DER penetrations across all service areas. Last, IREC recommended that the Commission should provide detailed upfront guidance on goals for and contents of utility distribution system plans (like CA and NY), with additional guidance through subsequent rulings.

The Department did not support either a uniform planning process or the creation of a distribution planning process, noting that it was unclear when or at what thresholds a planning process would be beneficial. The Department suggested as issues arise, stakeholders or the utilities could bring them to the Commission's attention.

As to the frequency and timing of plan submittal, Xcel suggested an annual filing that summarized the results of their annual planning process and provide, at a higher-level, any large-scale projects that stem from its internal annual planning process. OTP indicated that if required to be filed at all, plans should be reviewed on metrics or criteria, and not merely on scheduled timeframes due to concerns that an annual review could obstruct immediate system needs - DEA shared this concern.

Staff has proposed that a set 'phased' or threshold approach not be utilized. Initially, staff has proposed a one-year filing cycle for Xcel and DEA and two-year filing cycles for OTP and MP independent of any threshold triggers.[10] For example, OTP suggested review could conducted by the Commission when there have been, or there are, planned significant changes to the system – such as number of customers impacted, cost of a certain distribution project, MW size of a DER project, etc.

Staff believes that 'phases' in which a utility will move through are too dependent on each utility characteristics; staff does not see the value in setting parameters that will likely, in application, will have differing effects or outcomes. Commission review of each utility plan on an iterative and individual basis is the most effective (and adaptable) method of understanding each utility's circumstances and system status. Staff believes each iteration of information filing requirements or any modeling or forecasting exercises will be unique to each utility and largely depend on DER adoption rate by utility, available system technology, the utility's previous plan and stakeholder input, and other factors not yet known. Staff believes there are enough on-going industry developments and issues surrounding DERs and advanced system technologies, that a biennial check-in, even for utilities not experiencing high DER penetration, is reasonable.

[10] Staff has proposed initial file dates as November 1, 2018 for Xcel, and November 1, 2019 for DEA, MP, and OTP – however those dates are part of the draft MN-IDP's for each utility and will be open for comment, if the Commission authorizes this to proceed.

2. Approval of Plans and Prudency Determinations

Most utilities agreed that a formal 'approval' of a utility's annual (or near-term) distribution system plans would not be practicable; approval of specific annual investment plans would hinder speed with which distribution system needs have to be addressed. DEA argued that due that only long-term plans (10-20 year) could allow sufficient time for review by the Commission. Xcel indicated (similar to DEA) that shaping the planning framework (versus involvement in the annual capital planning process) is where stakeholder would provide the greatest value.

It was suggested by most commenters that guiding principles or criteria to be used in planning and Commission review of the plans, would be a better approach that a micro-managements of near-term, and specific, utility investment decisions.

AEE suggested that the Commission approve the utility plans, but approval should not constitute a formal finding of prudency: "if approval of the plans were to constitute a finding of prudency, that finding could have the unintended consequence of making the distribution system planning process overly formal and contentious, with parties needing to invest significant resources of time and money to engage…"[11]

Staff has proposed that the Commission 'accept' rather than 'approve' MN-IDP filings and does not believe the Commission's acceptance should constitute a prudency determination. Staff agrees with AEE's characterization and potential unintended outcome that could come with a finding of prudency. Additionally, staff believes that even a formal approval of the plans may become overly burdensome (in the same manner in which AEE suggests could occur with a prudency determination). The filings are intended to obtain a better understanding and dialogue surrounding forthcoming investments and planning considerations and to provide a forum to proactively address where additional information or planning considerations are needed; but it is not intended to micromanage or replace utility investment decisions. However, staff believes the Commission should have the option to reject a MN-IDP filing if it is insufficient or inconsistent with the Commission's guiding principles and previous ordering points.

Further, as the draft distribution system plan requirements show, staff does not believe that the Commission's review approval of a DSP would hinder necessary and on-going distribution system investments or construction. Staff agrees and supports the utility's need to meet the needs of their customers and if there are any instances in which a person believes the proposed MN-IDP may impede that process, utilities should file comments with the Commission.

3. Metrics or Criteria for Commission Review and Plan Development

Staff believes the guiding principles proposed by staff in the March 2016 Staff Report still apply and should be the guideposts for future distribution system plans:

[11] AEE Comments – Part C, Page 3.

- 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.

Several commenters (notably IREC and FE) advocated for an overarching goal of the integration and optimization of DERs. Staff believes these goals are inherent in the guiding principles above, as well as in Minnesota Statute, and has not proposed to modify the guiding principles at this time. Xcel suggested that criteria used for assessment could follow integrated resource planning metrics and OTP and DEA suggested use of the standard principles of reliability, economics, and impacts to customers (DEA also included risk considerations). The integrated resource planning metrics are noted for Commission consideration:

> Minn. Rule 7843.0600, Subp. 3: Factors to Consider: In issuing its findings of fact and conclusions, the commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
> A. maintain or improve adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> D. enhance the utility's ability to respond to change in the financial, social, and technological factors affecting its operations; and,
> E. limit the risk of adverse effect on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Others suggested that the Commission must be sure to utilize some degree of societal cost tests in evaluation of plans as well as the creation of a comprehensive benefit cost analysis framework one that can compare traditional utility solutions to DER solutions (this is discussed in more detail in the non-wires/alternatives section, below).

4. Uniformity of Commission Adopted Planning Requirements

Most commenters agreed with the need for flexibility in requirements for each utility, but believed there were likely a common set of factors to consider. AEE suggested two categories, stakeholder engagement (which should be uniform) and planning tools and methodologies. AEE noted that planning tools and methodologies that should be considered (to some level) for all utilities are: probabilistic forecasting of multiple DER and load growth scenarios, hosting capacity, locational value of DER, interconnection studies, and a uniform cost-benefit framework.

Xcel agreed that a common framework with common scenarios or sensitivities could work, however, if the Commission would like to get to a common planning framework, scenarios, or sensitivities, it will likely need to evolve over time – potentially using guiding principles to shape the evolution of utility planning tools. OTP stressed that any uniform process (which is argued against) would need to have the ability for utilities to meet their unique customer needs and system constraints.

Staff agrees with most all the comments on this topic, and has proposed a consistent stakeholder process across utilities, but has adapted planning tool specific requirements to be utility-dependent (see A-D, attached). Staff also strongly agrees that both the stakeholder process and planning tool requirements will adapt and progress with each utility filing.

B. Integration of MN-IDP with other Commission Processes

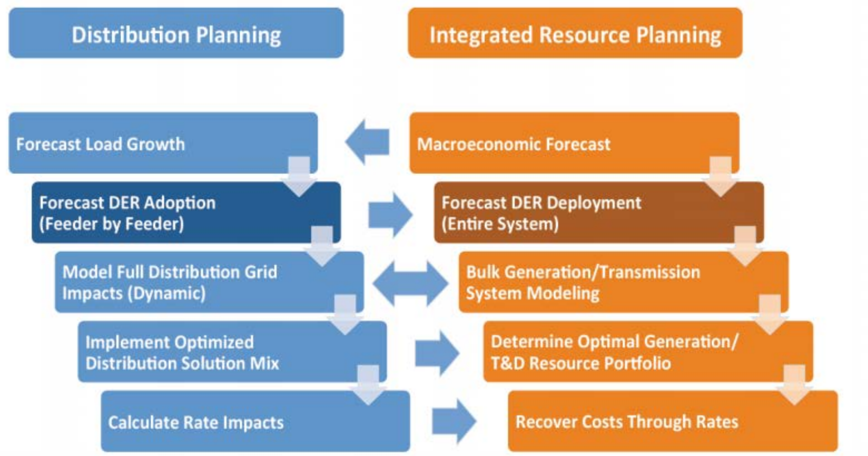
Most all utilities noted that a fully integrated process was not yet achievable for several reasons, however some indicated that with on-going and future improvements in planning tools and foundational investments in grid technologies, greater visibility and planning will likely be possible in the future.

There was a divergence between non-utility stakeholders and utilities on this topic. The non-utility stakeholders advocated for a fully integrated process in all aspects of planning (integrated resource plans (IRP), biennial transmission plans, and any distribution system plan). Some commenters argued that integration of these processes would allow for greater consideration of non-wire alternatives. Alevo argued that filing requirements imposed from the Commission should integrated a comprehensive plan on investment across generation, transmission and distribution assets – including cost-effectiveness tests for technology solutions (which Alevo futher detailed services that should be quantified). Alevo then argued that these plans should serve as the foundation for multi-year rate plans.

However, the utilities indicated that the three processes (resource plans, transmission plans, and distribution plans) do inform one another, but are separate for the immediate future to the distinct nature of their inputs and separate internal systems. [12]

[12] http://eta-publications.lbl.gov/sites/default/files/lbnl-1006047.pdf page 67 .

Figure 5. Proposal to Integrate Distribution and Resource Planning



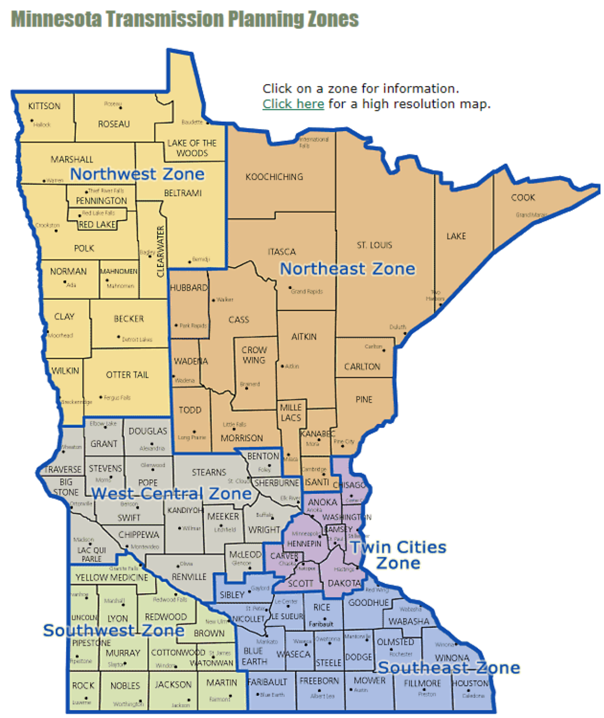
Staff believes the viewpoints are not entirely independent from one another; while the processes are likely not immediately able to be 'merged', there are general connections and practices that can be implemented. First, inputs to any process should be as consistent as practicable - load forecasts, energy efficiency, or other inputs should be similar (to the extent possible) between the planning models. If they are differing inputs, the utility should explain the basis for those differences in their IDPs. To conform to the Commission guiding principles, stated above, utilities will need to continue to align their processes in the future, and for now, to the extent possible.

Second, staff believes that Minnesota Statutes already *require* some level of integrated planning between processes. Both the Certificate of Need statute (Minn. Stat. § 216B.243) and the Biennial Transmission Plan (Minn. Stat. § 216B.2425) require consideration of non-wires alternatives and distributed generation projects by the Commission prior to approval. The Biennial Transmission Plan requirement specifically requires that any future transmission inadequacy be presented to the public (in a stakeholder forum) and requires that a discussion be held on potential alternatives (including non-transmission alternatives) that could be used to address those future inadequacies.[13] Staff believes while past filings may have had cursory information on why those alternatives were not viable, the Commission could require additional, and more in-depth, information - including more thorough cost-benefit analyses from any proposer of a Minnesota-based transmission projects.

[13] See Minn. Rule 7848.1000, Subp. 2.

Additionally, staff believes that there may be useful coordination and stakeholder input opportunities available through the Biennial Transmission and Distribution Statute. That Statute also requires broad stakeholder outreach by our Minnesota-transmission-owning utilities (MTOs). In 2011, the Commission waived the public meeting requirements of the stakeholder outreach process due to historic lack of participation by the public. However, to fully integrate planning in the future, an expanded use of the meetings required by Minn. Rule 7848.0900 as well as more comprehensive filing data and analysis, may be beneficial. Staff notes, however, that the Transmission Planning Zones do not align with the service territories of our rate-regulated utilities.[14,15] Staff has not proposed a coordinated approach for these processes at this time, but believes additional discussion may be appropriate in either (1) the forthcoming consideration of the next Biennial Transmission Plan in Commission Docket 17-377, which will likely be up at an agenda meeting in May 2018, or (2) future MN-IDP dockets. If the Commission sees value in this approach, additional comments could be solicited on this topic.

Figure 6. MN Transmission Planning Zones



C. MN-IDP Stakeholder Engagement Process

Separate from stakeholder coordination and integration with the Biennial Transmission Projects Report, staff has proposed a more focused and targeted stakeholder engagement process within the context of each utility's MN-IDP.

Comments received on stakeholder involvement largely encouraged stakeholder input surrounding the broader aspects of planning and considerations given to how a utility could plan.

Xcel noted that it believed the two areas of the process would be beneficial for stakeholders to engage would be (1) long-term area studies as they arise (ex. Hollydale and Hiawatha) and (2) DER and EV forecasts and information for use in annual planning processes. [16]

OTP indicated they believed there was limited interest by stakeholders to participate in the planning or review of its distribution system. DEA suggested that stakeholder participation in the planning process could best be achieved through the development of standard solutions, which utilities could select and utilize to meet the short term and/or long term needs of our consumers. DEA suggested an example would be standardized vendor offerings of energy storage systems,

---

[14] See November 30, 2017 Comments from the Communities United for Responsible Energy (CURE) in Dockets 17-377, 17-776, and 17-777.
[15] See MTO's website: http://www.minnelectrans.com/minnesota-zones.html
[16] Staff notes it is unclear what thresholds would trigger future long-term area studies by Xcel.

for residential, commercial or utility scale that utilities could apply as a solution (i.e. water heaters).

AEE advocated for direct stakeholder engagement in all steps of plan development (during development, review of drafts, and review of final plans) and advocated for third party facilitators. IREC suggested direct, consistent, and iterative stakeholder participation throughout the process (including comments on plans, in-person engagement through work groups and workshops, and encouraged the Commission to review stakeholder participation roadmaps in states like MA, NY, and CA). Alevo advocated for stakeholder input into high-level guidance, then leaving the plan development to the utilities, and following submittal, additional input into the utility proposals.

Currently, staff has proposed a standard stakeholder review process that requires the utilities hold at least one stakeholder meeting prior to a November 1 filing that allows sufficient time to modify their plans in response to any appropriate stakeholder input. Following any November 1 filing, the Commission will issue a notice of comment period – and if deemed reasonable by staff, a Commission-convened stakeholder meeting may be scheduled.

Of note, FE provided a specific process to immediately tackle two areas of the distribution system planning process (and pertaining only to Xcel). FE proposed that the Commission (1) require Xcel to make a compliance filing on demand and DER adoption forecasts[17], (2) initiate a comment period to allow stakeholder to provide input, and (3) designate a lead commissioner to facilitate record development and make recommendations to the full Commission (based on a written comment period). Staff discussed FE's proposal in the next section.

D. Scenario Analyses and Forecasting

Utilities and stakeholders provided detailed comments on scenario analyses and forecasting, in many cases, staff believes the terms 'scenario' and 'forecast' were used interchangeably by commenters. Staff believes both are tools used to look at potential futures and defines the terms as follows:

Forecast: A calculation or prediction based on a result of study or analysis of available data.

Scenario: A postulated sequence or development of events.

There was large agreement among the comments that: (1) transparency is important in the creation and/or selection or any forecast and scenario, (2) stakeholder input in the development of the scenarios is critical, and (3) scenarios should be adjusted based on utility-specific circumstances. Staff agrees with these points. Inputs into the scenarios (load growth, EV penetration, etc.) - informed by data forecasts - should be consistent with inputs used for other planning models. To the extent the data is not consistent, a utility should provide reason.

[17] FE noted the compliance filing required from Xcel should include both a description of Xcel's current demand forecasting practices and changes in its methodology since 2007, whether additional changes are necessary, and identification of currently available DER forecasting tools and methodologies.

Xcel expressed concerned with the potential detail and extent that may be required of distribution system modeling:

> "Unlike IRPs where a forecasted system peak is applied as a sensitivity at a macro level, distribution planning involves developing an individual forecasted peak for each major component on the system – which currently involves more than 1,700 individual forecasts, based on the present 1,274 feeders and 449 substation transformers. Increasing the numbers of scenarios and/or sensitivities would have an exponential impact on the volume and complexity of analysis. Distribution planning tools that would efficiently perform analysis of multiple scenarios, such as that which occurs at a system level in IRPs are not widely developed or available. We acknowledge that DER is expanding on our system. We are monitoring available planning tools as they are maturing, and will incorporate them into our process as appropriate."[18] CUB agreed with Xcel's characterization, that planning tools are yet to evolve to be able to inform this type of planning. Several parties agreed that traditional peak load forecasting will need to evolve as failure to account for DER load growth will limit potential for cost-effective investments. MP indicated it currently does not plan its forecasts considering DERs since DER as adoption is low, and it would only do so as warranted.

At this time, staff is not recommending that the amount of scenarios and data used in IRPs is replicated here. Staff proposes that all utilities contemplate three scenarios over the action plan timeframe (5-year) and long-term outlook (15-year) to the extent they can model or consider these scenarios on their system:

- base case (expected future)
- base case plus 10 percent DER adoption (10 percent + expected growth percentage)
- base case plus 25 percent DER adoption (25 percent + expected growth percentage)

Staff does not provide the specifics of these scenarios (and required forecast inputs) for each utility and suggests further record development (during the comment period on the draft MN-IDPs) about the proposed scenarios for each utility. Staff would recommend that each utility file, in the initial comment period on the MN-IDPs, proposed demand and DER adoption forecasts with sufficient detail to explain the factors and data that went into its proposal and a narrative about how it would intend to conduct the scenario analyses and any known assumptions it would make in doing so. Staff believes the staff resources of each utility, the methods used to execute these scenario analysis could vary by utility.

To the extent needed, staff encourages the utilities to reach out to stakeholders for input. Staff believes this approach aligns with Fresh Energy's proposal for stakeholder participation in forecasting, however staff is open to other options the Commission may want to pursue.

[18] Xcel Comments – Part A.

E. Applicable Standards and Interoperability

AEE indicated two main categories of standards that it deems important, 1) interconnection standards (and the forthcoming IEEE 1547 revisions), and 2) interoperability standards. First, AEE noted the importance of interconnection standards to be able to speed the process of new generator interconnections as well as interact across and between state and federal jurisdictions. AEE recommended that any interconnection standard update should include input from the Mid-Continent Independent System Operator (MISO) and the Federal Energy Regulatory Commission (FERC). Second, AEE referred the Commissioners to the National Institute of Standards and Technology (NIST) for consideration of interoperability standards.

DEA and OTP both stressed that DERs should be held to the same standards as any resource intending to interconnect to the distribution system. Both utilities are active participants in the Commission's update of Minnesota's statewide interconnection standards (Docket No. E999/CI-16-521) which includes updating statewide technical requirements to be consistent with IEEE Std. 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (published April 6, 2018). The technical subgroup in that docket will take up interoperability issues at its July 20, 2018 Web-Ex meeting.

Staff has not proposed any other stakeholder processes or further work at this time on interoperability. Staff believes that the utilities, in each of their annual or biennial filings, should describe its (1) plan for an interoperable network and (2) its basis for determining that its proposal is the most cost-effective and reasonable approach. There is debate in many planning forums regarding to what extent the utility is allowed to make vendor, technological, or otherwise, decisions for its own systems - versus having state prescribed direction on interoperability and other communication standards. Some states have elected to establish working groups and, some, established rules on communication requirements and protocols. While staff has not proposed further state-based development regarding interoperability, if any of the Commissioners would like to pursue other methods of managing this crucial and important topic, via workshops, stakeholder forums, or other methods – staff assist in revisions of the attached planning filing requirements, as needed. Staff also believes that the first iterations of filings (especially from Xcel and DEA) may shed more light on the matter, providing additional information on the way in which utilities are proposing to proceed and their basis and analysis for it, and inform the Commission whether additional state-based guidance will be required.

F. Third Party Data Access

There was a variety of viewpoints expressed on issues related to third party participation, third party access to grid data, and to a lesser degree, customer data. Utilities tended to express preferences to limit data sharing due to privacy and security concerns while other stakeholder expressed the importance of sharing data in optimizing the grid.

AEE[19] and IREC, as well as other parties, supported allowing access to data such as:

[19] AEE suggested Commission review of NIST Interagency Report 762817 and that it provides an analytical framework for utilities and regulators to consider, including recommendations for security requirements and concerns, data

- Existing distribution characteristics at substation and feeder-level —coincident & non-coincident peaks, capacity levels, outage data projected investment needs
- Generation production characteristics, including those associated with variable resources
- Existing combined heat and power installations
- Hosting capacity at substation and feeder level
- Distribution planning data
- Customer DG adoption forecasts
- Other customer DER adoption forecasts
- Distribution planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan.

Xcel provided useful points in Part C reply comments about the current state of data sharing in Minnesota on several fronts:

1) Existing regulatory, legal, and industry frameworks missing for distribution grid data compared to G&T level data (NIST, NERC, FERC)
2) Commission's authority to impose and enforce data protection does not extend to third parties unrelated to provision of regulated utility service
3) No alternative legal framework in MN to impose or enforce privacy, confidentiality, security requirements on third parties
4) Registration process for third party access to grid maps and data may be an appropriate protection protocol but need to consider Commission's jurisdiction and authority, plus administrative considerations
5) Unclear whether Commission's authority extends to EV ownership info

OTP cited CEII concerns and the Commission's previous review and docket on the issue of customer data. OTP suggested issues surrounding data access should be deferred to a working group as there are many perspectives and considerations.

Xcel noted that it believed some data that is not public includes system operating models, customer energy, capacity, or load profile data, system load data, and quantified risk data – because it could identify system vulnerabilities. However, Xcel noted there may be exceptions, like there are for MISO CEII, based on third parties meeting certain conditions or committing to nondisclosure provisions, for example.

There appear to be many unresolved issues relating to data sharing and access – on customer data as well as grid data. Staff believes the reporting requirements, as laid out in Attachment A-D which require utilities to file data management plans as part of their overall grid plan and strategy is the first step the Commission should take. This would allow the Commission and utilities to having discussions that could produce actual outcomes (versus simply theoretical conversations about what is possible). Staff has proposed that utilities create and share data management plans – both for customer and system data. From those proposals, the Commission can evaluate, with stakeholder input, whether those plans find

---

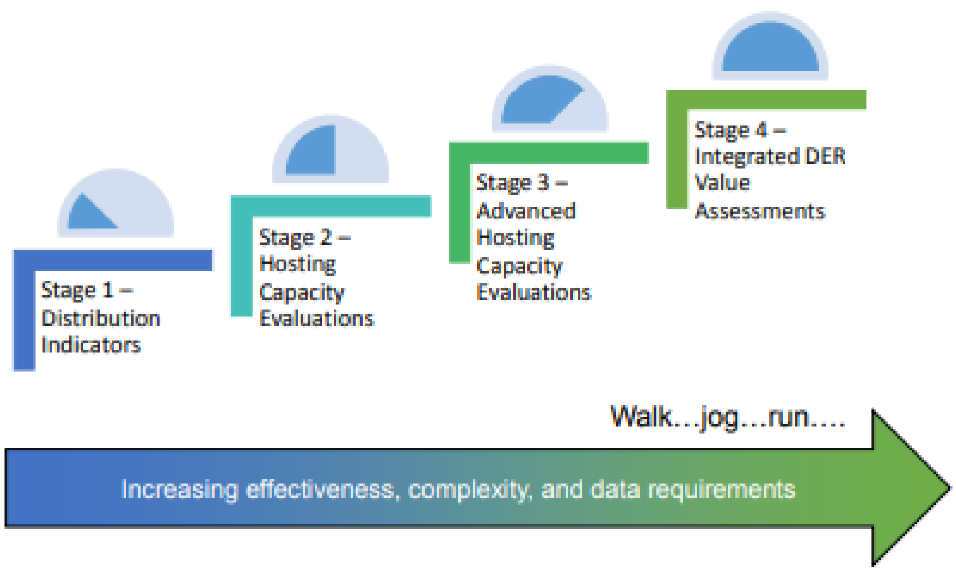
privacy, and systems cybersecurity.

ways to optimize system performance and cost. If the filings do not optimize system performance or utilize least cost system solutions, the Commission always has the ability to open investigations in areas that need further Commission oversight either generally or for a specific utility.

G. Hosting Capacity

There was variation in the responses from the commenters on what level of hosting capacity data should be available, from who, on what timeframe, and how. The smaller utilities indicated that they are currently experiencing no difficulty in personally working on each DER interconnection request and system impact review due to the low volume of requests. Staff believes this is a crucial point. There is a lot of interest and work on-going regarding hosting capacity analyses[20] and outcomes of obtaining the data; however, staff believes the most foundational piece for state's implementation of any sort of hosting capacity requirements is consideration of the need for the exercise and the cost to do so. Below is a basic figure on the steps in an evolving hosting capacity study, staff believes the most important step as a regulator is to ensure the requirements are only imposed when the cost of doing so will provide sufficient value as an outcome.[21]

Figure 7. Example Hosting Capacity Implementation Roadmap



AEE suggested that location-specific data down to the feeder, distributed-generation interconnection agreement queues, and specific hosting capacity values should all be accessible and hosting capacity analyses (HCA) should become more granular over time but should be guided by intended use cases.

[20] Xcel Energy Docket E002/M-17-777.

[21] MN PUC Grid Modernization: Distribution Planning Workshop Slides, Oct. 24, 2016 (Defining a Roadmap for Successful Implementation of Hosting Capacity Method for New York State, EPRI 2016)

Xcel noted that it currently made hosting capacity data, queued generation (with a signed GIA), minimum and maximum hosting capacity and the limiting violations available in its most recent HCA report.

OTP indicated that a discussion among stakeholder regarding what hosting capacity information is needed, what it would represent (and doesn't represent) would be warranted to set clear expectations on amongst stakeholders. OTP expressed concerns over data and security. OTP noted that a hosting capacity analysis was likely not yet warranted on its system, and recommended thresholds of some type be established to trigger when the HCA may be reasonable.

DEA indicated that in order to have useful discussions around HCA needs, more structure needs to be placed around the definition of a HCA and how the results of a HCA would ultimately be used. DEA indicated it had concerns about how the results may be interpreted and that saturations levels at a feeder or substation could trigger needs for a larger transmission study.

MP suggested that HCA should likely be discussed in a different forum, potentially the interconnection standards docket. MP indicated that a HCA discussion may be best served in the formal resource planning process "simply because this filing already addresses many of the different considerations on the distribution system." Otherwise MP suggested that another alternative would be a new docket dedicated specifically to DER planning – similar to Xcel's current Biennial Transmission and Distribution Plan docket in which a HCA was required as part of the compliance process. Regardless of location for the discussion, MP noted that issues regarding system data would need to be managed.

CUB argued that HCA is a key data point for customers and third parties considering DER investments. CUB agreed with other comments made that HCA when combined with DER forecasting and locational valuation allows for identification of areas of the grid in which DER can connect at lowest cost and potentially alleviate system issues. IREC recommended using the HCA to assist in the automation of the interconnection process and suggested the Commission should determine how best to merge Xcel's work in the statutorily-required HCA with Xcel's broader integrated distribution planning work.

At this time, staff has proposed minimal HCA-related reporting requirements from the three non-Xcel utilities, DEA, MP and OTP.[22] Staff agrees that due to the low level of DER interconnection requests, requiring any additional data or work would be costly and not (yet) add value commensurate with the cost associated with conducting a full HCA. Below staff has provided an Implementation Roadmap created by the Electric Power Research Institute. Staff suggests the

[22] At least some of the requested data points are also data, if it exists, that are required in the pre-application report and/or technical review process for interconnection applications in the proposed update to Minnesota's statewide interconnection standards. See MN PUC, Notice for Comment on Draft Staff Recommendations for Minnesota Statewide Interconnection Process, Attachment A, Section 1.4, p. 6-7 and Section 3.2, p. 13-14.

Commission revisit the filing requirements, and the guidance below, following the initial MN-IDP filings from each of the utilities.[23]

Figure 8. Hosting Capacity Implementation Roadmap

Stage	Consideration	Data Requirements	Output
1 – Distribution Indicators	Possible indicators such as - Estimated Minimum load levels - Voltage class - Substations over a MW threshold typically indicative of substation backfeed	- Currently available data - Understanding the interconnection queue	- Provides an indication where certain substations/feeders may have high costs associated with interconnecting DER
2 – Hosting Capacity Evaluations – Radial Systems	- Feeder-level hosting capacity calculations based on power system impact evaluations - Impact factors include voltage, thermal, and protection, safety/reliability	- All feeders modeled in service territory with regular updates for existing DER and queued DER mapped into planning models	- Feeder-level hosting capacity determinations
3 – Advanced Hosting Capacity Evaluations	- Refined nodal/section-based hosting capacity - Possible substation/transmission constraints - Operational and planning flexibility for changing configurations	- Transmission assessments and mapping of distribution-level impacts to transmission - Normal and reconfigured system models	- Refined hosting capacity evaluations that take into account additional criteria
4 – Fully Integrated DER Value Assessments	- Deferred or avoided planned capital upgrades - Improve system efficiency - Enhanced power quality, reliability, and resiliency	- Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics	- Comprehensive hosting capacity and DER value assessments considering both distribution and transmission

For Xcel, Staff has proposed that Xcel's MN-IDP filing would be due on November 1, 2018 (as proposed in the schedule noted above). Staff proposed the November 1, 2018 filing date to align with two other filings to be made from Xcel.

First, Xcel's next statutorily-required HCA is scheduled to be filed on the same date, November 1, 2018 - on an annual cycle - per the Commission's August 1, 2017 Order in Docket M-15-962.[24]

Second, Xcel had requested in its November 1, 2017 (statutorily-required) Biennial Distribution System Report filing[25] that it be authorized to file its next Biennial Distribution Projects Report on an *annual* basis instead of biennially (requesting to file November 1, 2018 instead of 2019). Staff would expect if this current docket (on MN-IDP filing requirements) is able to stay on this timeframe, all would benefit from the coordinated effort and plans.

---

[23] Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, June 2016, EPRI

[24] MN PUC August 1, 2017 *Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report*

[25] Commission Docket E002/M-17-776: The Commission will consider Xcel's latest Biennial Distribution Projects Report, filed on November 1, 2017 in May 2018.

Additionally, and related to comment made by stakeholders, staff is aware of locational valuation work that is proceeding in under the Community Solar Gardens Docket (E002/M-13-867) as well as other open Commission dockets. It is anticipated that additional learnings will be forthcoming from the stakeholder group to be convened from the Minnesota Department of Commerce. Therefore, staff believes additional information will be available following Xcel's 2018 distribution system plan filings and it would be counter-productive and premature to advance this issue here, at this time as any work may be redundant for parties.

H. Draft Utility-Specific IDPs Proposed to be Released for Comment

As noted, staff has attached a draft IDP for each utility. The proposed processes are similar in many respects but vary in the following ways:

1) **Filing Dates:** Xcel and DEA's plans are to be filed an annual cycle, commencing November 2018. OTP and MP plans are to be filed biennially (every other year) commencing November 2019.
2) **Hosting Capacity and Interconnection Requirements:** The data filing requirements for DEA, OTP and MP are minimal in nature and are to the extent available/accessible. Xcel is required to submit a summary of its related Hosting Capacity docket and progress.
3) **Distributed Energy Resources Futures:** All utilities are required to submit proposed scenarios, however they are at the discretion and the ability of the utility to draft a proposal on how the scenario is created and how it will be modeled.

All other requirements are similar between the utilities, however as noted, staff believes these requirements will likely diverge further over time. All items listed in the attached draft filing requirements are proposed to be open for comment and input is welcome from utilities and stakeholders.

VI. Decision Options

Docket 18-251 – Xcel Energy

1. Authorize staff to release the attached draft Integrated Distribution Plan filing requirements for Xcel out for comment.
2. *Fresh Energy Proposal*:
   - Require Xcel Energy to file, within 60 days of the Commission's Order, a report detailing:
     - Xcel's current demand forecasting practices for distribution system planning, including a description of methodology used to determine the "conservative" forecast. The filing should discuss how Xcel has modified its methodology in light of the observed change in demand growth rates since 2007 and whether Xcel believes additional adjustments are necessary.
     - The currently available DER forecasting tools and methodologies, with the goal of determining DER growth scenarios (baseline, low adoption, and high adoption) to be incorporated into Xcel's Q4 2018 distribution planning analysis.
     - Initiate a comment period to allow stakeholders to provide input on Xcel's compliance filing and recommendations for DER scenarios and demand forecasts; and
     - Designate a Lead Commissioner to facilitate record development and provide recommendations on DER scenarios and demand forecasts to the full Commission;

Docket 18-253 - Otter Tail Power

3. Authorize staff to release the attached draft Integrated Distribution Plan filing requirements for Otter Tail out for comment.

Docket 18-254 – Minnesota Power

4. Authorize staff to release the attached draft Integrated Distribution Plan filing requirements for Minnesota Power out for comment.

Docket 18-255 - Dakota Electric

5. Authorize staff to release the attached draft Integrated Distribution Plan filing requirements for Xcel out for comment.

Staff recommends decision options 1, 3-5.

DRAFT - MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
For Xcel Energy
Docket E002/CI-18-251

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.

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

Distribution System Plan Process

1. **Filing Date:** Require Xcel to file annually with the Commission beginning on November 1, 2018 an Integrated Distribution Plan (MN-IDP or IDP) for the 15-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. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (M-17-776).

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

   At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) 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, a 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]

   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. Detailed information on system visibility and measurement (feeder-level and time interval) and planned visibility improvements, include data on amount of 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
   7. Discussion if and how IEEE Std. 1547-2018[2] impacts distribution system planning considerations

   Financial Data

   8. Historical distribution system spending for the past 5-years, in each category:
      a. Existing system maintenance
      b. System expansion, or improvements, unrelated to growth in system capacity (MW)
      c. System expansion that were only required to meet historical and forecast growth in total system capacity
      d. Specific projects to address locational constraints, power quality issues or violations
      e. Other relevant categories not covered here
   9. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
   10. Planned distribution capital projects, including drivers for the project (e.g. load growth, reliability, aging infrastructure, etc.), timeline for improvement, summary of anticipated changes in historic spending
   11. 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 and Large Scale Distribution System Area Projects

   12. Current DER deployment by type, size, and geographic dispersion
   13. Information on areas of existing or forecasted high DER penetration or voltage or frequency issues that result in abnormal conditions

---

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.
[2] IEEE Standard 1547-2018, published April 6, 2018.

B. Hosting Capacity and Interconnection Requirements

1. Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how Xcel anticipates the hosting capacity analysis (HCA) to facilitate interconnection applications in the future, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.
2. Describe the data sources and methodology used to complete the initial review screens outlined in the (proposed) Minnesota DER Interconnection Process.

C. Distributed Energy Resource Futures Analysis

1. Define and develop scenarios regarding increased DER deployment. Include both anticipated gross load and actual and anticipated DER penetration. Provide a discussion of system impacts, potential barriers to DER integration, and any grid or system upgrades necessary to accommodate the DER at the listed penetration levels. Scenarios should be a reasonable mix of individual DER and aggregated or bundled DER service types, and geographic dispersal, as anticipated for Xcel. Scenarios should include at a minimum:
    - base case (expected future)
    - base case plus 10 percent DER adoption (10 percent + expected growth percentage)
    - base case plus 25 percent DER adoption (25 percent + expected growth percentage)

2. Xcel should include information on methodologies used to develop its scenario discussions (including whether inputs are or are not consistent with integrated resource planning inputs), expected DER load profiles (any individual or bundled), sources of data, any geographic deployment assumptions, and any other relevant assumptions factored into the scenario discussion. Xcel should include information on anticipated impacts from FERC Order 841[3] and a discussion of potential impacts from FERC Docket RM-18-9-00.

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

1. Xcel shall provide a 5-year Action Plan and 15-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.

    The 5-year Action Plan should include a detailed discussion and costs on planned distribution system investments planned for the next 5-years. Xcel should include specifics of the 5-year Action Plan related investments. Topics that should be discussed, at a minimum:
    - Overview of investment plan: scope, timing, and cost recovery mechanism
    - Grid architecture plan
    - Alternatives analysis of investment proposal: alternatives considered, alternative cost and functionality analysis, implementation order options, and considerations made (e.g. IVVO vs. FLISR)
    - Interoperability and communications strategy

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

- 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.)
- Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
- Customer anticipated benefit and cost
- Customer data or grid data management plan
- Plans to manage rate or bill impacts, if any
- Impacts to net present value of system costs (in NPV RR/MWh or MW)

The 15-year long-term plan should include a discussion on potential investments based on Xcel's planned 5-year Action Plan and the DER future scenarios. The Action Plan and long-term plan should include an assessment of load growth, expected net load changes, and what changes are necessary to incorporate DER into future planning processes.

E. Non-Wires Alternatives Analysis

1. Xcel shall provide a detailed discussion of all distribution system projects in the preceding year or coming 5-years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the preceding year, which cost five million dollars or more, provide an analysis on how a non-wires alternatives compare, at a minimum, in price, functionality, and long-term value.
2. Xcel shall provide information on the following:
   - Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
   - 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)
   - Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
3. Xcel shall provide a discussion of all listed projects in the most current-year Biennial Transmission Project Report, the anticipated cost of those projects, and a cost benefit analysis on why a distribution-system or distributed generation project was or was not in the public interest.

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

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

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

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

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-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 filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure that modifications to the MN-IDP can be incorporated into the November 1 filing as deemed appropriate by the utility.

   At a minimum, Otter Tail should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) 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, a 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]

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.

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. Detailed information on system visibility and measurement (feeder-level and time interval) and planned visibility improvements, include data on amount of 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
7. Discussion if and how IEEE Std. 1547-2018[2] impacts distribution system planning considerations

Financial Data

8. Historical distribution system spending for the past 5-years, in each category:
    a. Existing system maintenance
    b. System expansion, or improvements, unrelated to growth in system capacity (MW)
    c. System expansion that were only required to meet historical and forecast growth in total system capacity
    d. Specific projects to address locational constraints, power quality issues or violations
    e. Other relevant categories not covered here
9. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
10. Planned distribution capital projects, including drivers for the project (e.g. load growth, reliability, aging infrastructure, etc.), timeline for improvement, summary of anticipated changes in historic spending
11. 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 and Large Scale Distribution System Area Projects

12. Current DER deployment by type, size, and geographic dispersion
13. Information on areas of existing or forecasted high DER penetration or voltage or frequency issues that result in abnormal conditions

[2] IEEE Standard 1547-2018, published April 6, 2018.

B. Hosting Capacity and Interconnection Requirements

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 Futures Analysis

1. Define and develop scenarios regarding increased DER deployment. Include both anticipated gross load and actual and anticipated DER penetration. Provide a discussion of system impacts, potential barriers to DER integration, and any grid or system upgrades necessary to accommodate the DER at the listed penetration levels. Scenarios should be a reasonable mix of individual DER and aggregated or bundled DER service types, and geographic dispersal, as anticipated for Otter Tail. Scenarios should include at a minimum:
   - base case (expected future)
   - base case plus 10 percent DER adoption (10 percent + expected growth percentage)
   - base case plus 25 percent DER adoption (25 percent + expected growth percentage)

2. Otter Tail should include information on methodologies used to develop its scenario discussions (including whether inputs are or are not consistent with integrated resource planning inputs), expected DER load profiles (any individual or bundled), sources of data, any geographic deployment assumptions, and any other relevant assumptions factored into the scenario discussion. Otter Tail should include information on anticipated impacts from FERC Order 841[3] and a discussion of potential impacts from FERC Docket RM-18-9-00.

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

1. Otter Tail shall provide a 5-year Action Plan and 15-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.

   The 5-year Action Plan should include a detailed discussion and costs on planned distribution system investments planned for the next 5-years. Otter Tail should include specifics of the 5-year Action Plan related investments. Topics that should be discussed, at a minimum:
   - Overview of investment plan: scope, timing, and cost recovery mechanism
   - Grid architecture plan
   - Alternatives analysis of investment proposal: alternatives considered, alternative cost and functionality analysis, implementation order options, and considerations made (e.g. IVVO vs. FLISR)
   - Interoperability and communications strategy
   - 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.)
   - Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)

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

- Customer anticipated benefit and cost
- Customer data or grid data management plan
- Plans to manage rate or bill impacts, if any
- Impacts to net present value of system costs (in NPV RR/MWh or MW)

The 15-year long-term plan should include a discussion on potential investments based on Otter Tail's planned 5-year Action Plan and the DER future scenarios. The Action Plan and long-term plan should include an assessment of load growth, expected net load changes, and what changes are necessary to incorporate DER into future planning processes.

E. Non-Wires Alternatives Analysis

1. Otter Tail shall provide a detailed discussion of all distribution system projects in the preceding year or coming 5-years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the preceding year, which cost five million dollars or more, provide an analysis on how a non-wires alternatives compare, at a minimum, in price, functionality, and long-term value.
2. Otter Tail shall provide information on the following:
    - Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
    - 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)
    - Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
3. Otter Tail shall provide a discussion of all listed projects in the most current-year Biennial Transmission Project Report, the anticipated cost of those projects, and a cost benefit analysis on why a distribution-system or distributed generation project was or was not in the public interest.

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

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

- 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.

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

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-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 filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure that modifications to the MN-IDP can be incorporated into the November 1 filing as deemed appropriate by the utility.

   At a minimum, Minnesota Power should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) 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, a 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]

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.

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. Detailed information on system visibility and measurement (feeder-level and time interval) and planned visibility improvements, include data on amount of 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
7. Discussion if and how IEEE Std. 1547-2018[2] impacts distribution system planning considerations

Financial Data

8. Historical distribution system spending for the past 5-years, in each category:
    a. Existing system maintenance
    b. System expansion, or improvements, unrelated to growth in system capacity (MW)
    c. System expansion that were only required to meet historical and forecast growth in total system capacity
    d. Specific projects to address locational constraints, power quality issues or violations
    e. Other relevant categories not covered here
9. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
10. Planned distribution capital projects, including drivers for the project (e.g. load growth, reliability, aging infrastructure, etc.), timeline for improvement, summary of anticipated changes in historic spending
11. 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 and Large Scale Distribution System Area Projects

12. Current DER deployment by type, size, and geographic dispersion
13. Information on areas of existing or forecasted high DER penetration or voltage or frequency issues that result in abnormal conditions

[2] IEEE Standard 1547-2018, published April 6, 2018.

B. Hosting Capacity and Interconnection Requirements

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 Futures Analysis

1. Define and develop scenarios regarding increased DER deployment. Include both anticipated gross load and actual and anticipated DER penetration. Provide a discussion of system impacts, potential barriers to DER integration, and any grid or system upgrades necessary to accommodate the DER at the listed penetration levels. Scenarios should be a reasonable mix of individual DER and aggregated or bundled DER service types, and geographic dispersal, as anticipated for Minnesota Power. Scenarios should include at a minimum:
    - base case (expected future)
    - base case plus 10 percent DER adoption (10 percent + expected growth percentage)
    - base case plus 25 percent DER adoption (25 percent + expected growth percentage)

2. Minnesota Power should include information on methodologies used to develop its scenario discussions (including whether inputs are or are not consistent with integrated resource planning inputs), expected DER load profiles (any individual or bundled), sources of data, any geographic deployment assumptions, and any other relevant assumptions factored into the scenario discussion. Minnesota Power should include information on anticipated impacts from FERC Order 841[3] and a discussion of potential impacts from FERC Docket RM-18-9-00.

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

1. Minnesota Power shall provide a 5-year Action Plan and 15-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.

    The 5-year Action Plan should include a detailed discussion and costs on planned distribution system investments planned for the next 5-years. Minnesota Power should include specifics of the 5-year Action Plan related investments. Topics that should be discussed, at a minimum:
    - Overview of investment plan: scope, timing, and cost recovery mechanism
    - Grid architecture plan
    - Alternatives analysis of investment proposal: alternatives considered, alternative cost and functionality analysis, implementation order options, and considerations made (e.g. IVVO vs. FLISR)
    - Interoperability and communications strategy
    - 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.)
    - Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)

---

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

- Customer anticipated benefit and cost
- Customer data or grid data management plan
- Plans to manage rate or bill impacts, if any
- Impacts to net present value of system costs (in NPV RR/MWh or MW)

The 15-year long-term plan should include a discussion on potential investments based on Minnesota Power's planned 5-year Action Plan and the DER future scenarios. The Action Plan and long-term plan should include an assessment of load growth, expected net load changes, and what changes are necessary to incorporate DER into future planning processes.

E. Non-Wires Alternatives Analysis

1. Minnesota Power shall provide a detailed discussion of all distribution system projects in the preceding year or coming 5-years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the preceding year, which cost five million dollars or more, provide an analysis on how a non-wires alternatives compare, at a minimum, in price, functionality, and long-term value.
2. Minnesota Power shall provide information on the following:
    - Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
    - 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)
    - Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
3. Minnesota Power shall provide a discussion of all listed projects in the most current-year Biennial Transmission Project Report, the anticipated cost of those projects, and a cost benefit analysis on why a distribution-system or distributed generation project was or was not in the public interest.

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

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

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

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.

Distribution System Plan Process

1. **Filing Date:** Require Dakota Electric to file annually with the Commission beginning on November 1, 2018 an Integrated Distribution Plan (MN-IDP or IDP) for the 15-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 filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure that modifications to the MN-IDP can be incorporated into the November 1 filing as deemed appropriate by the utility.

   At a minimum, Dakota Electric should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) 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, a 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]

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.

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. Detailed information on system visibility and measurement (feeder-level and time interval) and planned visibility improvements, include data on amount of 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
7. Discussion if and how IEEE Std. 1547-2018[2] impacts distribution system planning considerations

Financial Data

8. Historical distribution system spending for the past 5-years, in each category:
    a. Existing system maintenance
    b. System expansion, or improvements, unrelated to growth in system capacity (MW)
    c. System expansion that were only required to meet historical and forecast growth in total system capacity
    d. Specific projects to address locational constraints, power quality issues or violations
    e. Other relevant categories not covered here
9. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
10. Planned distribution capital projects, including drivers for the project (e.g. load growth, reliability, aging infrastructure, etc.), timeline for improvement, summary of anticipated changes in historic spending
11. 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 and Large Scale Distribution System Area Projects

12. Current DER deployment by type, size, and geographic dispersion
13. Information on areas of existing or forecasted high DER penetration or voltage or frequency issues that result in abnormal conditions

[2] IEEE Standard 1547-2018, published April 6, 2018.

B. Hosting Capacity and Interconnection Requirements

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 Futures Analysis

1. Define and develop scenarios regarding increased DER deployment. Include both anticipated gross load and actual and anticipated DER penetration. Provide a discussion of system impacts, potential barriers to DER integration, and any grid or system upgrades necessary to accommodate the DER at the listed penetration levels. Scenarios should be a reasonable mix of individual DER and aggregated or bundled DER service types, and geographic dispersal, as anticipated for Dakota Electric. Scenarios should include at a minimum:
    - base case (expected future)
    - base case plus 10 percent DER adoption (10 percent + expected growth percentage)
    - base case plus 25 percent DER adoption (25 percent + expected growth percentage)

2. Dakota Electric should include information on methodologies used to develop its scenario discussions (including whether inputs are or are not consistent with integrated resource planning inputs), expected DER load profiles (any individual or bundled), sources of data, any geographic deployment assumptions, and any other relevant assumptions factored into the scenario discussion. Dakota Electric should include information on anticipated impacts from FERC Order 841[3] and a discussion of potential impacts from FERC Docket RM-18-9-00.

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

1. Dakota Electric shall provide a 5-year Action Plan and 15-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.

    The 5-year Action Plan should include a detailed discussion and costs on planned distribution system investments planned for the next 5-years. Dakota Electric should include specifics of the 5-year Action Plan related investments. Topics that should be discussed, at a minimum:
    - Overview of investment plan: scope, timing, and cost recovery mechanism
    - Grid architecture plan
    - Alternatives analysis of investment proposal: alternatives considered, alternative cost and functionality analysis, implementation order options, and considerations made (e.g. IVVO vs. FLISR)
    - Interoperability and communications strategy
    - 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.)
    - Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)

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

- Customer anticipated benefit and cost
- Customer data or grid data management plan
- Plans to manage rate or bill impacts, if any
- Impacts to net present value of system costs (in NPV RR/MWh or MW)

The 15-year long-term plan should include a discussion on potential investments based on Dakota Electric's planned 5-year Action Plan and the DER future scenarios. The Action Plan and long-term plan should include an assessment of load growth, expected net load changes, and what changes are necessary to incorporate DER into future planning processes.

E. Non-Wires Alternatives Analysis

1. Dakota Electric shall provide a detailed discussion of all distribution system projects in the preceding year or coming 5-years that are anticipated to have a total cost of greater than five million dollars. For any forthcoming project or project in the preceding year, which cost five million dollars or more, provide an analysis on how a non-wires alternatives compare, at a minimum, in price, functionality, and long-term value.
2. Dakota Electric shall provide information on the following:
    - Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
    - 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)
    - Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
3. Dakota Electric shall provide a discussion of all listed projects in the most current-year Biennial Transmission Project Report, the anticipated cost of those projects, and a cost benefit analysis on why a distribution-system or distributed generation project was or was not in the public interest.