414 Nicollet Mall
Minneapolis, MN 55401

July 21, 2017

—Via Electronic Filing—

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

RE: RESPONSE TO QUESTIONNAIRE-SECTION C
GRID MODERNIZATION
DOCKET NO. E999/CI-15-556

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Response to Section C of the Commission's April 26, 2017 Corrected Notice of Comment Period on Distribution System Planning Efforts and Considerations in the above-referenced Docket.

Pursuant to Minn. Stat. §216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on all parties on the attached service list. Please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Enclosure
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE COMMISSION INVESTIGATION INTO GRID MODERNIZATION: FOCUS ON DISTRIBUTION SYSTEM PLANNING

DOCKET NO. E999/CI-15-556

RESPONSE

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this response to Section C of the Commission's April 26, 2017 CORRECTED NOTICE OF COMMENT PERIOD ON DISTRIBUTION SYSTEM PLANNING EFFORTS AND CONSIDERATIONS in the above-referenced Docket.

Section C of the Notice asks whether there are ways to improve or augment utility planning processes – and requests all stakeholders to discuss the identified subjects or any others that relate to the efficient and economic investment in technological advancements, infrastructure and integration of DER into distribution system planning and operations.

Below we first discuss the landscape addressing the national perspective of these issues, followed by our responses to the Commission's questions contained in Section C of the Notice.

LANDSCAPE

In May 2015, the Commission initiated an inquiry into grid modernization, with a focus on distribution system planning – aiming to identify steps it could take to advance grid modernization to the benefit of Minnesota's electricity consumers.[1] The Commission defined grid modernization, identified key drivers for further grid modernization, and observed three guiding questions for Minnesota:

[1] Minnesota Public Utilities Commission Staff Report on Grid Modernization, page 1.

- Are we planning for and investing in the distribution system that we will need in the future?
- Are the planning processes aligned to ensure future reliability, efficient use of resources, maximize customer benefits and successful implementation of public policy?
- What Commission actions would support improved alignment of planning for and investment in the distribution system?

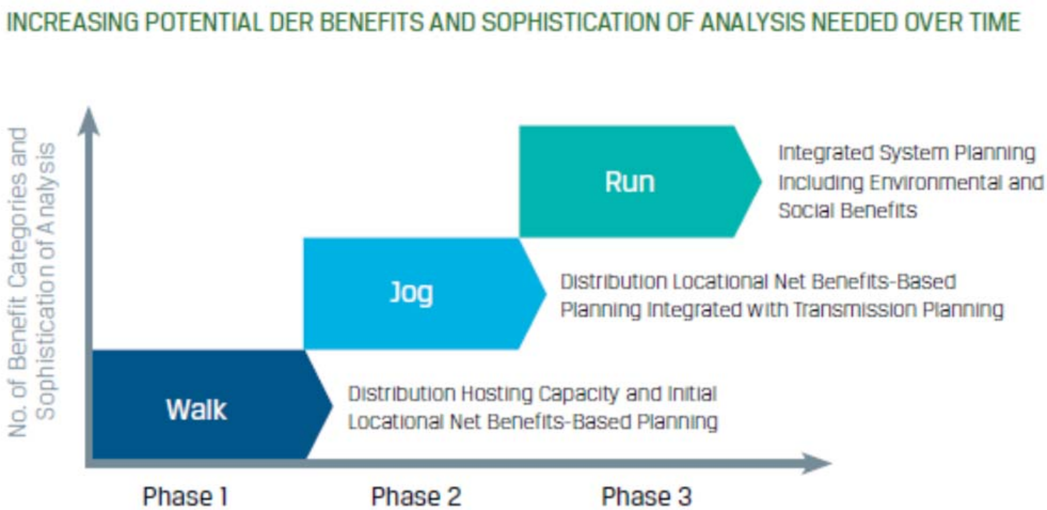
Other states are also engaging in grid modernization efforts, although with differing areas of focus. According to the NC Clean Energy Technology Center, over half of U.S. states are currently examining regulatory frameworks or actively working to deploy advanced grid technologies. The top common grid modernization actions in Q1 2017 were the areas of AMI deployment, smart grid deployment, and time-varying rates.[2]

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere.

While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The stages are illustrated in Figure 1 below.

[2] *See 50 States of Grid Modernization, Q1 2017 Quarterly Report,* NC Clean Energy Technology Center (May 2017).

Figure 1: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. *See* White Paper.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, distributed energy resources (DER), the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or integrated resource planning (IRP).

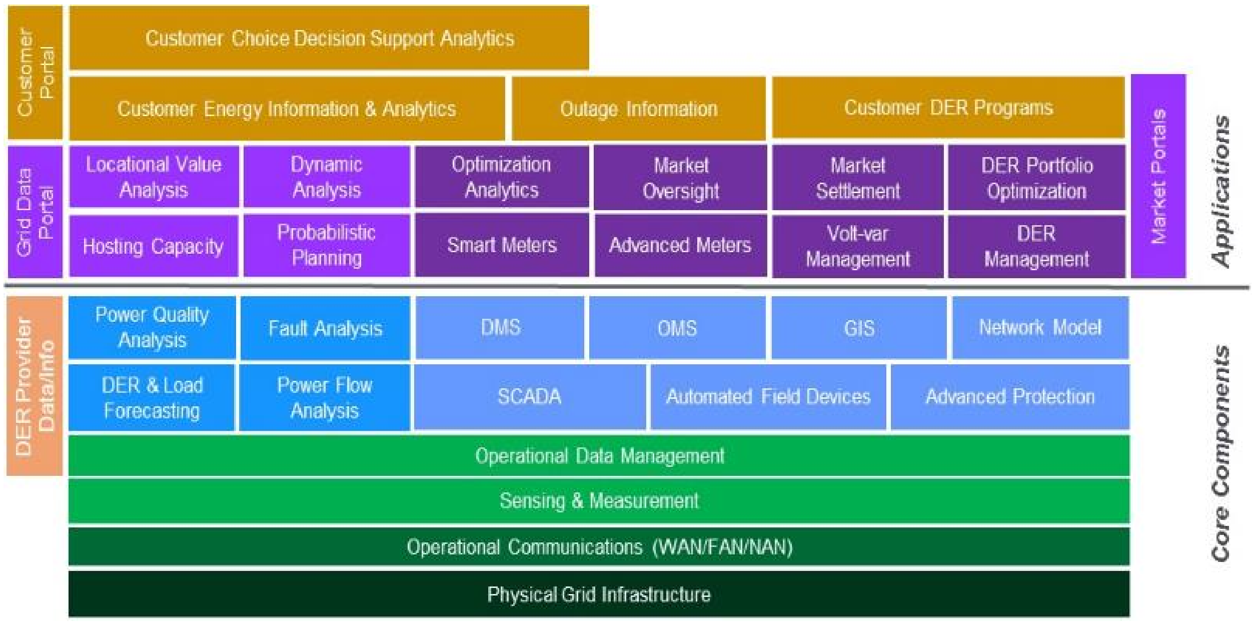
Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[3] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy (DOE), as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly

[3] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in Figure 2 below.

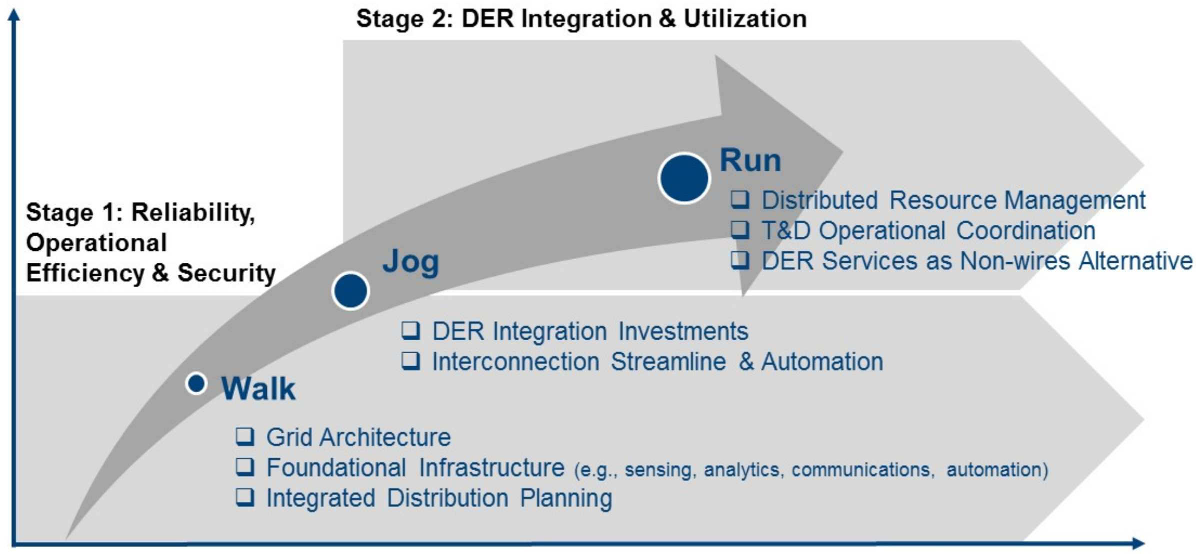
Figure 2: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

The DOE's efforts also recognize timing and pace considerations, as shown in Figure 3 below.

Figure 3: Timing and Pace Considerations



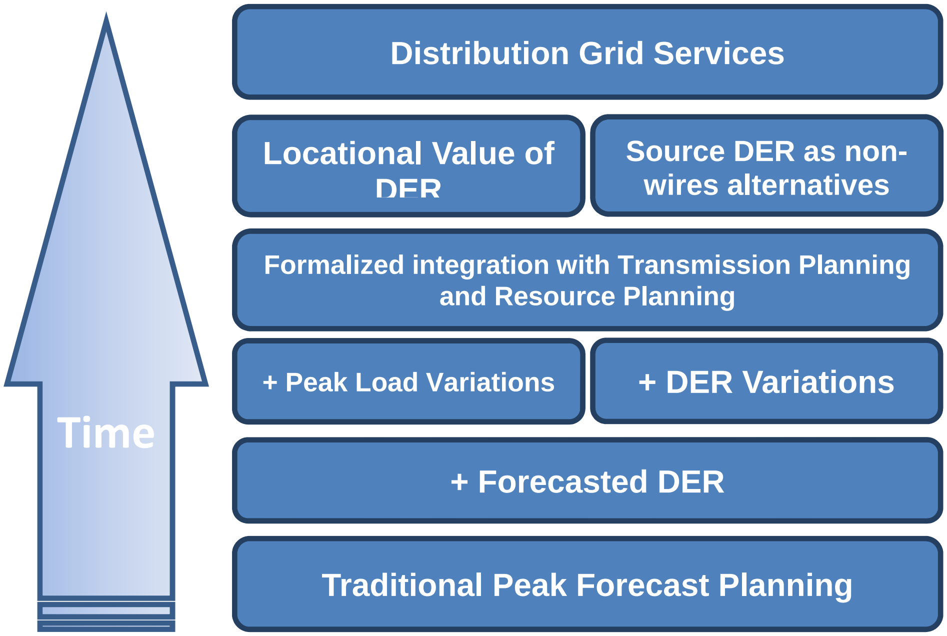
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We would agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 4 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 4: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[4] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates to the five-year action plan period of an IRP, which is generally a continuation of past IRPs. Distribution systems are utilities' point of connection for customers. While an

[4] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "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: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

unexpected loss of a macro system component, such as a power plant, can often be covered by the Midcontinent Independent System Operator (MISO) system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

Like IRPs, changes to the distribution planning process will also need to consider related processes. For example, investments stemming from our current annual distribution planning process make-up only approximately 20 percent of the overall distribution business area budget. Some of these investments "cross-over" to other distribution investment categories, such as asset health. All distribution investments are approved as part of a rate case. We believe the focus of any changes to the distribution planning process should be in terms of process, data sharing, and advancing state policy objectives as opposed to challenging the state's current regulatory model or discussing opportunities for third party ownership of various distribution components.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value. We also look forward to continued dialogue with stakeholders and guidance from the Commission as Minnesota joins other leading states to prepare for the future.

RESPONSE TO COMMISSION'S NOTICE

1) Evaluation of utility plans. Discuss:

   a. How utility distribution plans should be used in other proceedings: Should distribution plans be approved by the Commission? If so, what are the implications for cost recovery, i.e., to what extent would Commission approval of a plan constitute a finding of prudence?

Unlike an IRP, which is long-term, and examines the system and external influences on the system at a macro level, distribution planning is a near-term, high volume analysis conducted at localized levels – and its exclusive input presently is a peak load forecast. Its current primary purpose is to identify and mitigate existing or impending capacity issues to ensure reliability for customers – and the outcome is a series of proposed risk mitigations that become an input into the overall distribution business area budgeting process, so may or may not be funded when compared with other proposed distribution system expenditures. All distribution system investments are weighed and prioritized in the budgeting process using criteria that considers our obligation to provide safe, adequate, efficient, and reasonable service, along with customer cost implications, and prevailing policy objectives. Overall Distribution business area investment levels are reviewed and approved as part of a general rate case.

Our current annual distribution planning process involves each planning engineer developing workpapers that capture system risks and mitigations that are later prioritized across all planning engineers. The majority of these mitigations are straightforward equipment upgrades and installations to remedy current or expected capacity/reliability risks. The overall timeline is relatively short – five years total – with the mitigations focused on the second year. Some mitigations are further time-sensitive, such as customer-driven changes that must meet customer in-service deadlines, and equipment failures that must be remedied quickly. While IRPs must adapt to changing conditions and influences, these changes are not comparable to those on the distribution system, which must continually adapt to dynamic and sometimes immediate customer, equipment, and other issues across many thousands of points on the system.

For these reasons, we believe annual distribution plans do not lend themselves to an "approval" process similar to IRPs, which are grounded in Minnesota statutes and rules, and thus have prescribed content, procedures, defined linkages with other processes such as certificates of need, and standards of review. Rather, we believe the Commission could issue guiding principles that would aid utilities in evolving their planning processes and supporting planning tools. For example, the Commission may want utilities to examine scenarios other than peak load, and certain levels of DER in various geographies/portions of their utility service areas. Utilities could submit an annual report summarizing the results of their present annual planning process – and to the extent they do not yet have the tools to incorporate the Commission's planning guidance, also provide an update on where they are in that process. This would increase transparency into utility planning processes for the Commission and stakeholders, and allow processes that are fundamentally needed to maintain customer reliability to continue uninterrupted.

b. How specifically should an approved distribution system plan be integrated with other planning activities: resource planning, interconnection, transmission, or others?

While our current planning practices involve interfacing with transmission planning and resource planning, today they are not integrated. Distribution planning forecasts are and should continue to be an input to the transmission planning process, which is more integrated with resource planning. As DER penetration becomes substantial and distribution planning practices and tools mature, we expect the exchange of information across these areas will increase in scope and specificity.

The August 2016 ICF International *Integrated Distribution Planning* report outlines an example "walk, jog, run" path to the opportunities envisioned in a more distributed future through integrated distribution planning.[5] The ICF report explains that the answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization and the desired policy objectives. We agree this will be an evolution that is important to begin planning for and taking action toward now.

To the extent DER forecasts are performed by resource planning as part of an IRP, that forecast can become an input to the annual distribution planning only to the extent it can be applied at a feeder level, which is contrary to current IRP macro-level planning processes. Therefore, a more practical approach may be macro-level DER forecasts that are grounded in a set of criteria, such as penetration rates by geographic area or location. Distribution planning would then derive and apply a localized forecast to its engineering analysis – and/or could incorporate stakeholder-provided DER or Electric Vehicle (EV) geographic concentration information in its planning process.

Using DOE's timing and pace considerations that portrays the walk, jog, run analogy (see Figure 3 above) in two stages, we are in Stage 1. Our primary focus is on safety, reliability, asset health, and investing in the foundational distribution system to prepare it for advancing technologies, improved system management, support for increasing DER, to achieve increasingly stringent industry reliability objectives, and to provide customers with products and services they are coming to expect. These foundational investments include the Advanced Distribution Management System (ADMS), a Field Area Network (FAN), Advanced Meter Infrastructure (AMI), and other advanced applications and associated field devices that support a more advanced grid.

ADMS is underway in Minnesota and is the fundamental platform that will manage the complex interaction of DER, outage events, feeder switching operations, and enables other advanced applications and field devices. One of the other advanced applications also underway in Minnesota is the Fault Location Isolation and Service Restoration (FLISR), which involves software and automated switching devices to decrease the duration and number of customers affected by any individual outage – reducing the frequency and duration of customer outages. The FAN is the communications network that will enable communications between the

[5] The ICF report was filed in Docket No. E999/CI-15-556, on September 13, 2016.

communications infrastructure that already exist at our substations, the ADMS, and the new intelligent field devices associated with other advanced applications. AMI meters will replace existing Automated Meter Reading meters with more advanced technology to improve service and reliability. They are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," enabling near real-time monitoring between the meter and ADMS. AMI meters provide information about customer usage and will enhance our ability to send price signals to customers, allow for new rate structures that will allow customers to manage their energy usage with near real-time energy usage data available through a customer web portal, identify outages without customer reporting, and respond efficiently to metering and usage issues.

These foundational investments will move the system from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. It will also enable greater customer choice by providing the infrastructure to allow the Company to offer new products, services, and technologies, including access to near real-time data regarding customer electric usage – and will also include security protocols that will protect against, detect, and remedy cyber and physical threats. Additionally, the advanced grid will provide timely and accurate information that will allow the Company to manage the increasing amount of DER entering our system. These foundational elements are essential before we can "jog" and then "run."

Like other states embarking on this path, we are also taking action to improve our planning practices and tools to prepare for the future that may involve changes to the distribution operating model to recognize market values, costs, and operating characteristics for DER in terms of energy, capacity and grid services – like exist today for large-scale generation and transmission. In the interim, we look forward to working with stakeholders to understand what is important to Minnesota – and as our tools and foundational system capabilities advance – help determining appropriate proxies for the market values, costs and operating characteristics to apply in the planning process that evolve our practices while maintaining customer, value such as reliability and cost.

c. What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?

Currently, we engage stakeholders in the planning process primarily as part of our long-term area studies rather than our annual planning process. As we described in our response to Sections A and B of the Commission's Notice, we sometimes need to perform an area study to adequately respond to an issue identified in the annual planning process. In that circumstance, we engage in a broader study of a geographic area and develop proposals to solve the identified capacity issues and risks. We have historically engaged with stakeholders for input into these studies. In that context, we have found that the majority of stakeholders have primarily been interested with siting, routes and visual impacts, rather than the need/issue, or technical considerations.

We have however, seen some shift in the level of involvement stakeholders are seeking at the distribution level – for example, in understanding the planning process, grid modernization plans, and the specific available capacity to integrate DER at various points on the system. We look forward to continued dialogue with stakeholders on these important issues in the context of Minnesota policy drivers and customer value – and in relation to how the distribution planning process links with other regulatory processes such as rate cases. We also believe there will be an even greater role for collaboration among stakeholders regarding the evolution of the distribution operating model to recognize market values, costs, and operating characteristics for DER in terms of energy, capacity and grid services, as we discussed in our response to Question 1.b above – and ongoing as and after the model evolves.

In terms of the planning process, as we have previously discussed, the overwhelming majority of risks identified in the annual planning process can be met with straightforward solutions, such as adding capacitor banks, small feeder and substation additions and configurations, etc. These are often relatively low cost changes or upgrades to the existing grid, rather than more involved – and thus costly – changes that require new connections to the transmission system, for example. This level of planning relies on engineering calculations and judgment, and requires detailed examination and understanding of system components and attributes – some of which may not be public. This level of planning is also time-sensitive, so depending on the level and extent of stakeholder involvement, there could be risks to the timeliness of project development and completion – and thus, customer reliability. Finally, the annual planning process becomes an input to an overall distribution business area budgeting process, where it represents approximately 20 percent of overall capital expenditures, and is subject to review as part of a rate case.

Involvement in the annual planning process is also currently limited by the lack of planning tools that contemplate stakeholder involvement. Providing stakeholders with meaningful information in order for them to engage in recommendations would require Planning Engineers to become data-gatherers and spend considerable time "packaging" the data to be meaningful to external parties. Involvement in full system analyses also raises questions about the level and extent of system data that is appropriate to share with external parties. The MISO has a data designation called Critical Energy Infrastructure Information (CEII). Today, there is not a similar designation for certain distribution system information, but we believe that these types of designations should be explored for the distribution system.

We believe there are two components of the annual planning process for stakeholders to engage: (1) the long-term area studies; and (2) to provide DER and EV input into the annual planning process.

Long term area studies. As part of a long-term area study that we conduct as an outcome of the annual distribution planning process, stakeholders may have ideas to solve the identified issue or risk. There may also be circumstances where we would issue a Request for Proposals (RFP) to aid identification of possible solutions. For context, we believe that an RFP for a potential non-wires alternative (NWA) as part of the planning process would be in the "run" stage. We note that we could include a summary of the area study and results of the RFP in an annual distribution planning informational filing, along with our selected solution.

DER and EV input. As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level. We believe stakeholders may have valuable input into DER and EV adoption rates and locations that could help inform utility planning scenarios. Utilities would need this input to be coordinated and realistic, however, in order for it to be useful to the planning process. For example, we would need no more than one forecast of each type of DER or EVs that all parties agree is reasonably representative of the patterns of adoption. Utility planning engineers would then be able to use this information in combination with other planning considerations to examine system impacts, risks and mitigating actions.

Through broader collaboration and partnership, we believe we can constructively move toward solutions that appropriately balance interests and maximize value for customers.

d. Criteria or metrics the Commission should use in evaluating proposed distribution plans

As we have discussed above, we believe the results of utility distribution planning efforts could be submitted to the Commission as informational, but should not be subject to Commission approval. Public utilities are required under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service. Distribution planning, or the annual act of planning the system for sufficient capacity, is not easily isolated from the overall distribution business area planning and budgeting processes to allow for an isolated review. The Commission currently evaluates utility operational performance through service quality reporting and financial performance through general rate cases – both of which we believe are currently the appropriate measures and venues to consider the results of our planning efforts.

As we have discussed in our response to Sections A and B, as well as this Section C to the Notice, Distribution planning differs greatly from IRPs. IRPs are based on both Minnesota statutes and rules. The factors the Commission considers in issuing its findings of fact and conclusions for IRPs are prescribed in Minn. R. 7843.0500, subp. 3, as follows:

A. Maintain or improve the 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 changes in the financial, social, and technological factors affecting its operations; and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Along with these factors, Minn. R. 7843 prescribes the entire utility resource planning process, including the content of the plans and their relationship to other Commission practices. We believe Minnesota will need to approach distribution planning with a similarly thoughtful process.

e. How often should a utility distribution plan be submitted for Commission review?

As we have described, distribution planning is driven by the immediacy of customer reliability impacts and is an ongoing process, due to the dynamic nature of the distribution system. For example, our plans may change when a new customer comes onto the system, or when an existing customer adds load that we need to take action to support. We could submit an annual informational filing that summarizes the results of our annual planning process. While it would increase the transparency of our planning process for stakeholders, it may not be very meaningful, given our current tools – and fact that the overwhelmingly majority of outcomes are small/straightforward projects that comprise approximately 20 percent of the overall distribution business area budget. It will also quickly become out-of-date, due to the dynamic nature of the distribution system. Perhaps a more meaningful annual informational filing could summarize any large-scale projects stemming from the planning process and/or progress we are making in our planning processes.

2) Feasibility of planning enhancements. Discuss:

a. Whether all investor-owned utilities should adopt uniform planning processes

While there may be benefits to a common methodology, each utility has different data capabilities, information systems, and other resources to do their planning. Each of the utilities also have unique geographic footprints and mixes of customers. As we have discussed above, however, we believe there could be common framework elements each utility would apply to their planning efforts. For example, common scenarios or sensitivities, such as related to DER or their forecasts. This would be similar to the approach taken in California and New York, where each utility filed their plans to implement the respective commissions' guidance and directives.

We note additionally that utilities' abilities to apply multiple inputs rely on the capabilities of their planning tools. As we described in our response to Sections A and B of the Notice, our current planning tools are only capable of using one input – which today is the peak forecast. So, if the Commission wishes to get to a common planning framework, scenarios, or sensitivities, it will likely need to evolve over time – perhaps starting with guiding principles that shape the evolution of utility planning tools.

b. Taking resource concerns into account, what are the events or system conditions that should trigger the adoption of enhanced planning processes by an individual utility? (e.g., high distributed generation interconnection requests, high DER penetration, high capital/operating budget needs, other)

The August 2016 ICF International *Integrated Distribution Planning* report outlines a three-stage evolution of distribution systems as it relates to DER adoption. Various changes in both distribution planning and operations are needed in each stage to ensure reliable distribution operations. We are taking a number of actions toward increasing levels of DER on our system. However, consistent with our response to Question 1.b above and our discussion of the walk-jog-run approach advocated by experts in the forefront of this issue, it is also necessary for foundational elements that enable increased utility tools and information to be in place.

As we have noted, the DOE has observed that U.S. utilities are in Stage 1, which includes evolving the planning processes and tools – and includes the addition of a hosting capacity tool, for example. It also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems. This aligns with our efforts to expand our Supervisory Control and Data Acquisition (SCADA) capabilities, implementation of an ADMS, and the other foundational items we have discussed that are necessary to advance the grid and its data capabilities, which will improve the information available to our planning and operations.

We note additionally that our current annual planning and budgeting processes contemplates events or system conditions that require deeper or broader study. We describe these "long-term area studies" in our response to Sections A and B of the Notice.

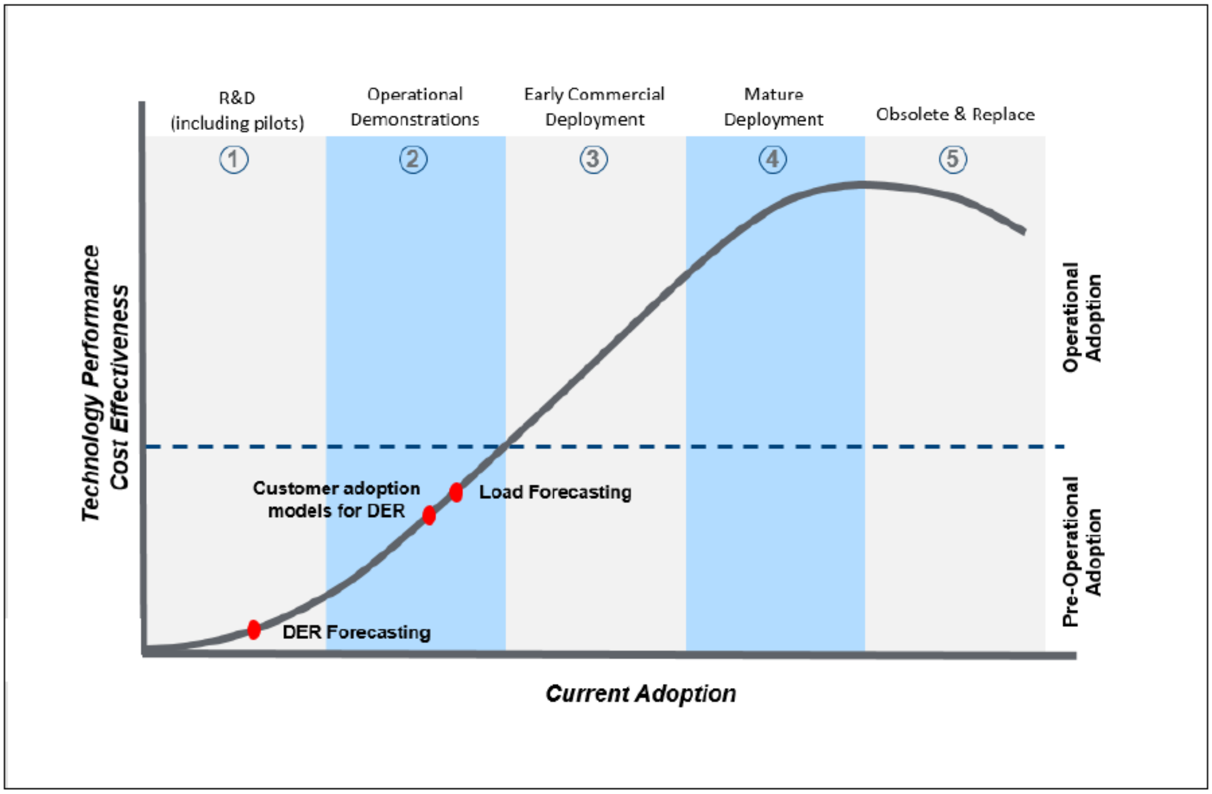
3) Forecasting. Discuss whether demand forecasting and DER modeling may be improved by:

a. Integrating system-wide forecasts, circuit-level forecasts, and forecasts of geographic dispersion of DER to map potential impacts, both beneficial and detrimental, of increased DER, or other

At this time, the level of DER on our system and the historical rate of interconnections have not had a significant impact on our forecasts. However, this is changing, particularly as a result of the Community Solar Garden Program. Long-term, we believe integrating various forecasts will be beneficial to our planning efforts, and we are currently working to identify tools that will facilitate this integration.

As shown in Figure 5 below, the availability of adequate forecasting tools has not reached full commercial deployment at this point, but we anticipate that they will in the near future. This function serves as the basis of distribution planning, and needs to be properly developed to enable more advanced planning and decision making.

Figure 5: Forecasting DER and Demand – Adoption Maturity Analysis



Source: *Modern Distribution Grid, volume II: Advanced Technology Maturity Assessment* by U.S. DOE Office of Electricity Delivery & Energy Reliability, version 1.1 (March 27, 2017). *See* U.S. DOE DSPx Modern Distribution Grid Vol. II

The August 2016 ICF International *Integrated Distribution Planning* report (Figure 11, page 21) outlines an example "walk, jog, run" path to the opportunities envisioned in a more distributed future through integrated distribution planning. The ICF report explains that the answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization and the desired policy objectives.

Using this concept as a base, we provide a snapshot of how we contemplate evolving our planning tools and process, applying to our tools, process steps, and actions as sophistication of analysis and processes increase over time as Figure 6 below.[6]

[6] Figure 6 is an extension of Figure 2 provided in Attachment A to our response to Parts A and B of the Notice.

Figure 6: Potential Planning Tools Evolution

	TOOLS	Current Process Steps: Forecast	Current Process Steps: Risk Analysis	Current Process Steps: Mitigation Plans	Current Process Steps: Budget Create	Current Process Steps: Design and Construct / EDP Memo	Current Process Steps: Long Range Plans	Future Planning Actions: Interconnection Processing**	Future Planning Actions: Scenario Planning	Future Planning Actions: Integrated Resource Planning	Future Planning Actions: Locational Net Benefit Analysis
Current Tools	Synergi Electric		X	X			X	X			X
	~~Distribution Asset Analysis*~~	~~X~~	~~X~~	-	-	-	-	-			
	MS Excel		X		X		X				
	CYMCAP		X								
	GIS			X			X	X	X		X
	SCADA	X									X
	Workbook (internal)		X	X	X	X					X
	DRIVE***		X	X				X			
Expanded Tools	New Forecasting Tool*	X					X	X	X	X	X
	ADMS	X							X		
	SAP					X					

* *New Forecasting Tool* replaces DAA and adds more functionality
** Planning has larger role in interconnection process
*** Hosting Capacity becomes integrated into planning process

Walk Jog Run

b. Using probabilistic analysis for availability of DER in high-DER-penetration scenarios, i.e. considering the likelihood of coincident failure or unavailability of multiple DER assets

We believe probabilistic analysis is a critical aspect of incorporating DER into the planning process. Without having a solid foundation of probabilistic analysis it will be difficult to reliably forecast the impact of DER on the distribution system.

4) Scenarios. Discuss:

To clarify, our view of Scenarios is that they are alternative future states of the distribution system. For example, high adoption of DER, no DER, a portion of DER with storage, DER on/DER off, high load growth/low load growth, etc. We believe the planning process would benefit from using multiple scenarios, when the planning tools evolve to allow for systematic examination of multiple scenarios and multiple inputs. We also believe the value from assessing the impacts of various levels and types of DER will be realized when the distribution operating model evolves to include energy, capacity and operating profiles to use in the planning process.

a. What type of input should stakeholders have into the selection of planning scenarios?

As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level. We believe stakeholders may have valuable input into DER and EV adoption rates and locations, for example, that could help inform utility planning scenarios. Utilities may benefit from a limited set of input, such as this, that is coordinated and well-vetted for use in the planning process in combination with other planning considerations to examine system impacts, risks and mitigating actions. However, as we have described, the distribution system is our direct connection point with customers, does not have the same redundancy and back-up as exists at the transmission and energy supply level, and generally requires solutions within short timeframes. Distribution planning outcomes therefore generally require more immediate action than an IRP, for example, to ensure customer reliability. So, any changes in process will need to ensure the focus remains on ensuring the reliability of the system for end use customers.

b. What criteria should be used by utilities to identify relevant planning scenarios?

We believe distribution planning will evolve to include:

- Historical and forecasted weather,
- Forecasted quantities and availability of DER
- Forecasted impacts of conservation and load control,
- Electric vehicle adoption,
- A 24/7 forecast rather than solely the peak load,
- Storage implications, and
- Inputs from an integrated energy supply/transmission/distribution planning

process.

Therefore, scenarios that contemplate high and low variations of the above – and variations such as customer mix, customer load profiles, load density and weather would additionally add value to the planning process. Finally, utilities will need better planning and forecasting tools that have the capabilities to incorporate these criteria.

c. Should all utilities use common planning scenarios, or should they be tailored to the circumstances of individual utilities?

As we have discussed, we believe that there could be some scenarios that apply to all utilities, like there are in IRPs. However, this issue is being addressed different ways nationally. The California Working Group on DER and Load Forecasting recommended different forecasting methodologies/ scenarios be used between the utilities but that common principles be followed:[7]

- Use statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation.
- Develop approaches to manage uncertainty associated with granular allocation of DER.
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data.
- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning.
- Integrate data from DER industry partners to enhance forecasting accuracy.

However, because distribution planning is grounded in location on the system, there is enough variability between utilities that we believe the majority of the planning analysis needs to be unique. Relevant variables include whether the utility is winter versus summer peaking, whether the system (or portions of the system) serve rural areas versus urban/dense population areas, types of DER being utilized, level of risk willing to be taken, corporate goals, company incentives, etc.

d. Should planning scenarios be common across multiple planning cycles, or should planning scenarios be redefined with each new planning cycle?

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[7] *See* http://drpwg.org/wp-content/uploads/2017/04/Joint-IOU-Draft-Assumption-and-Framework-Document.pdf

We believe there may be planning scenarios that remain constant across planning cycles until a new circumstance comes to light, or a review identifies the need for redefining or adding/subtracting scenarios. However, we expect analysis of other planning scenarios specific to each planning cycle may be needed to address timely subjects, such as technology advances.

e. **What are reasonable timeframes for each use and consideration of a scenario, and how often should they be reevaluated?**

We believe scenarios should be considered and reviewed on an annual basis as part of the annual planning process. We would anticipate that once the appropriate framework, or set of scenarios is determined, there will be little change from year to year.

5) Standards. Discuss:

a. **Standards and codes that will be applicable to the enhanced integration of DER into distribution system planning and operations**

A number of standards can apply to integrating DER, depending on the characteristics of the DER. The future revision of standard IEEE 1547, Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, will be in important standard to enhancing the integration of DER. We anticipate the drafting and revising of additional documents in the IEEE 1547 series will be initiated after the ongoing IEEE 1547 and IEEE 1547.1 revision process is complete and that the future documents may further assist with enhancing integration of DER, including energy storage. We list below other standards and codes that may be relevant to DER integration:

- IEEE Std 32-1972 (R1997), "IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices"
- IEEE Std 100-2007, "IEEE Standard Dictionary of Electrical and Electronic Terms"
- IEEE Std 141-1993 (R1999), "IEEE Recommended Practice for Electric Power Distribution for Industrial Plants – Red Book"
- IEEE Standard 142-2007, "IEEE Recommended Practice for Grounding of Industrial an Commercial Power Systems – Green Book"
- IEEE Std 242-2001, "Recommended Practice for Protection and Coordination

of Industrial and Commercial Power Systems"

- IEEE 446-1995 (R2000), "Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications"
- IEEE Std 519-2014, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems"
- IEEE Std 1547-2003 (R2008), "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems"
- IEEE Std 1547a -2014, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1"
- IEEE Std 1547.1 -2005 (R2011), "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems"
- IEEE Std 1547.1a-2015, "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1"
- IEEE Std 1547.2-2008, "Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems"
- IEEE Std 1547.3-2007, "Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems"
- IEEE Std 1547.4-2011, "IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems"
- IEEE Std 1547.6-2011, "IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks"
- IEEE Std 1547.7-2013, "IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection"
- IEEE Std P1547.8, "Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementing Strategies for Expanded Use of IEEE Standard 1547"
- IEEE 1453-2015, "IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems"
- IEEE C37.90-2005 (R2010), "IEEE Standard for Relay Systems Associated with Electric Power Apparatus"

- IEEE Std C37.90.1-2012, "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems".
- IEEE Std C37.90.2-2004 (R2010), "IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers"
- IEEE C37.95-2002 (R2007), "IEEE Guide for Protective Relaying of Utility-Consumer Interconnections"
- IEEE Std C62.41.2-2002, "IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits"
- IEEE Std C62.42-2005, "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits"
- IEEE Std C62.92.2-2017, "IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems"
- ANSI C84.1-2016, "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)"
- UL Std. 1741-2010, "Inverters, Converters, and Controllers for use in Independent Power Systems"
- NESC – "National Electrical Safety Code", ANSI C2 (2017), Published by the Institute of Electrical and Electronics Engineers, Inc.
- NEC – "National Electrical Code", NFPA 70 (2017), Published by the National Fire Protection Association.

6) Access to grid and planning data by customers and third parties. Discuss:

a. To what level should distribution planning data of Minnesota utilities be accessible to third parties

We have a responsibility to maintain the security of the system and our customers' privacy and confidentiality. We therefore believe we could make some system data available to third parties as long as it does not create system vulnerabilities or expose directly, or allow through reengineering, confidential or private details about our current or prospective customers.

b. Identify any categories of data that may be unsuitable for access, e.g. for reasons of security, trade secret, customer privacy, or burdensomeness

We noted above the MISO classification of some data as CEII and the need for a similar concept for distribution system information – and have touched on the issue of customer privacy and confidentiality. We believe examples of 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, we believe there may be exceptions, like there are for MISO CEII, based on third parties meeting certain conditions or committing to non-disclosure provisions, for example. Additionally, we would expect parties participating in an RFP to solve an identified system issue would require more detailed information, subject to non-disclosure provisions.

An additional concern regarding public release of this type of information would be its potential influence on business customers, particularly, if they were to rely on it to inform business decisions, such as expansions, rather than working with Company representatives for a more complete perspective of system capacity capabilities and expansion cost implications.

c. Discuss categories of data needed by third parties to:

i. Participate in developing system plans

As we have discussed, in addition to not-public data issues, we believe there are other issues associated with third parties participating in the annual planning process. However, if third parties were allowed to participate in future "jog" or "run" stages, categories of data may include:

- *System*: state of system along with configurations; elements, such as devices, transformers, and conductors; operating characteristics; and capacities, etc.
- *Load*: load profile; controllability; historical data; demand and energy data.
- *DER*: availability of resources; potential market adoption; operating characteristics; contractual obligations.

We believe at least a portion of this data would be subject to a non-disclosure agreement.

ii. Critically review proposed plans

In order to facilitate third-party review of our annual plan, we would need to create a Study from our data to make it suitable for review. We currently have only done this a few times in the past for prominent, public, long-range area studies (such as the

South Minneapolis Electric Distribution Delivery System assessment and the Plymouth and Medina Electrical System Assessment provided as Attachments C and D, respectively, to our June 21, 2017 response to Sections A and B of the Notice). We have not provided the underlying analysis data, but rather a finalized Study document. We discuss the outcome of our current planning process and propose an annual summary report in our response to Question No. 1 above, which we believe will increase transparency into the process while our tools evolve to anticipate stakeholder involvement.

iii. Prepare commercial projects in response to plans

We believe the information needed will depend on the circumstances driving the RFP for an identified issue – with some more straightforward than others. However generally, the data may include items such as: detailed load data, individual or aggregated customer data, forecasted load and DER growth, as well as geospatial and asset data in order for them to build an operating model. We believe at least a portion of this data would be subject to a non-disclosure agreement.

d. Discuss the availability and importance of a standard, downloadable format for customers and third parties to assess planning opportunities

We currently do not have one source of all data needed in the planning process. In order for customers or third parties to assess planning opportunities, they would need appropriate expertise and access to all of the data we identified and discussed in our response to Sections A and B of the Notice. It would be important to have a standard, electronic format, like there is currently with Strategist for IRPs. As we have discussed, at least portions of this data would be subject to non-disclosure provisions, as Strategist files for IRPs are currently. Creating such a tool for distribution planning would require time and resources – and the current planning tools to mature and/or new tools to be developed. Therefore, we believe this is something that would be part of the "run" stage – or perhaps in the latter part of "jog." We believe however, this is something that utilities could plan for as they evolve their planning tools – and after it is clear what data and with whom the Commission will require utilities to share data.

7) Hosting Capacity. Discuss:

a. What information should be made available to developers and the public, such as voltage, current generation, queued generation, peak and minimum load, and limiting factor criteria violations?

We currently make available through our hosting capacity report existing generation, queued generation that has a signed Interconnection Agreement, minimum and maximum hosting capacity and the limiting violation along with the substation and feeder names. We are working toward including the voltage of feeders with our 2018 report.

b. Provide a description, method, and technological and personnel resources necessary, including security or password requirements, for conducting hosting capacity and making the data/output of the analysis available to the public

We are currently conducting hosting capacity on an annual basis and have submitted the report publicly to the Commission.

The results from our first report, submitted December 1, 2016, are available in a table format on eDockets in Docket No. E002/M-15-962. We intend to provide a geospatial presentation of the results in future iterations of the report, including the report we submit November 1, 2017. We believe we have reasonably addressed the issues of security and access to-date. We continue to have some concern in mapping our entire distribution system, including critical customers. We are working toward determining a mapping format to aid in siting future DER facilities on the Company's system, while balancing system security and customer privacy and confidentiality concerns.

That said, we are aware that some other states, such as California, do include registration, security, and password requirements to access hosting capacity information.

c. How should and in what format should the results of a hosting capacity analysis be made available?

As discussed above, we will submit our 2017 hosting capacity report to the Commission via eDockets, and consistent with our 2016 report, it will contain a Microsoft Excel spreadsheet providing tabular data – and new for 2017, a visual representation of the hosting capacity results.

8) Strawman distribution planning outlines and/or processes are welcome.

We detailed our current process in our response to Sections A and B of the Notice, submitted June 21, 2017 – and have discussed improvements underway and potential areas for increased stakeholder involvement as part of this response.

9) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are relevant?

We believe it is important at this point in time to focus on preparing the distribution system for a future with greater levels of DER, which includes improving our field communication capabilities and evolving our tools. We believe the greatest value stakeholders could provide at this time is in shaping the planning framework, rather than direct involvement in the annual planning process.

CONCLUSION

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices. We appreciate the opportunity to provide our responses to Section C of the Commission's Notice, and ongoing participation in the dialogue about these important, foundational issues.

Dated: July 21, 2017

Northern States Power Company