STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
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In the Matter of a Commission Inquiry Into Grid Modernization

Docket No: E999/CI-15-556

Initial Comments of the Citizens Utility Board of Minnesota on the Commission Questionnaire, Section C

I. Introduction

The Citizens Utility Board of Minnesota ("CUB") appreciates the opportunity offered by the Minnesota Public Utilities Commission ("PUC" or "the Commission") to submit these initial comments regarding how best to advance modernization of the electric distribution grid to the benefit of Minnesota's customers, utilities and other stakeholders. Increased penetration of distributed energy resources ("DER") provides new benefits and opportunities for customers. However, many of those benefits and opportunities will arise only if stakeholders and regulators work to ensure that infrastructure investments, distribution system planning and ultimately utility actions are carefully structured. CUB offers these comments for the PUC's consideration on when and how the Commission and stakeholders can evaluate utility actions in the context of grid modernization and specifically, distribution system planning.

CUB is committed to reducing energy costs for the people of Minnesota by improving public policy, educating consumers about energy options, and offering personalized guidance on how to lower their electricity, natural gas and telecommunications bills. CUB's mission is to represent the interests of residential and small business utility customers in Minnesota by advocating for affordable and reliable utility service and clean energy. This includes not only examining the effects of proposed changes in rates and rate design but also examining utility efforts to modernize electric grid infrastructure.

In the coming decades, the U.S. electric industry is poised to invest trillions of dollars in technology that will transform the electric system. Digital and flexible demand management, storage and grid awareness technologies can enable the interconnection of DER and enable customers to manage their energy usage in new ways. However, by themselves utility investments in new technologies often do not by themselves result in benefits to customers. It is the responsibility of all stakeholders to ensure that efforts to modernize the electric grid create opportunities to expand DER investments and use data (usage, power quality, etc.) to streamline utility investments and create customer savings.

Utilities must be held accountable for ensuring that the benefits of grid modernization are realized – in many cases, simply purchasing a technology solution is a necessary but not sufficient condition for customers to benefit. However, grid modernization efforts can be worth it where net benefits to customers can be identified and realized. The Commission should focus on how to identify and lower any unreasonable or unnecessary barriers to these goals with the express purpose of lowering costs of service, improving grid reliability and resiliency, and allowing least-cost investment by customers into distributed energy resources. In doing so, the PUC does not have to become technical experts – the Commission can set policy by focusing on the functions which will be provided by utility investments, and ensuring a careful assessment of the costs and benefits of achieving any given function – for example, remote meter reading – is assessed.

CUB appreciates the opportunity to provide comments and looks forward to working with the PUC, utilities and stakeholders to identify opportunities to improve Minnesota's electricity distribution system to the benefit of all Minnesotans.

II. Background: What is "Grid Modernization?"

The Notice of Comment Period invites stakeholders to discuss topics that relate to the efficient and economic investment in technological advancements, infrastructure and integration of DER into distribution system planning and operations. One of the key questions many utilities and public utility commissions are struggling with is: What exactly does it mean to modernize the grid? In other words, what makes "grid modernization" investments different from the usual infrastructure investments utilities make to provide basic service?

While it is true that investments to "modernize" the grid don't have to be treated differently than traditional investments, commissions, utilities and stakeholders could miss opportunities to plan for the new demands being placed on utility to accommodate increased penetration of DER in a manner that keeps rates affordable, follows cost causation principles and provides reliable service if they are not looking for it.

Part of the challenge for any regulatory body is that for the first time, many regulators are looking at investments whose costs and benefits flow beyond just utility to customers and third parties. For example, the deployment of advanced metering infrastructure ("AMI") can reduce unaccounted for energy, labor costs and other costs associated with manual meter reading. However, the value of AMI as compared to say, the deployment of automated meter reading ("AMR") lies in its ability to provide granular data on usage, power quality, outages, etc. – data that can be used to improve service and support programs which lower customer bills through investments in energy efficiency and demand response measures. These programs in turn can depend on third parties offering ways for customers to save energy. Identifying, measuring and ultimately capturing those benefits requires all stakeholders to undertake a broader cost/benefit analysis than one focused on the utility's costs.

In these analyses, what stakeholders, utilities and commissions should focus on is not the a particular type of technology – e.g. Microsoft versus Apple - but the purpose of the technology – e.g. word processing. A commission's job is not to micromanage utility technology investments but ensure that the investments in question serve the goals of reliable and affordable service as well as broader policy goals. For that reason, Illinois expressly defined a "smart grid" as investments and policies that promote the following goals:

- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
- Dynamic optimization of grid operations and resources, with full cyber security. In this instance, "dynamic" means in as close to real-time as practicable.
- Deployment and integration of:
    - Distributed energy resources, including renewable, energy efficiency and demand-side resources.
    - "Smart" technologies, appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation. "Smart" technologies here are ones that can act in real-time, be automated and/or be interactive with customers.
    - Advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, thermal-storage air conditioning and renewable energy generation.
- Provision to consumers of timely information and control options.
- Development of open access standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

The ultimate goal of any of these policies is that customers benefit as much as possible from grid modernization investments. How can they do so? By having the purpose of any grid modernization focused on specific areas of benefits:

- Consumer benefits through improved usage information and ability to manage energy usage through energy efficiency, demand response and distributed generation investments, not only through expanded rate options that will give additional potential money-saving opportunities from energy conservation and load shifting but through new technologies made practicable by smart grid investments.
- Economic benefits through the support of new markets and innovation that leverage the infrastructure. Smart grid, and the data that results from its implementation, can create significant opportunities for innovation if the right rules are put in place to optimize access and functionality.
- Environmental benefits through smarter long-term generation and transmission investments and more efficient resource utilization, avoided greenhouse gas ("GHG") emissions associated with peak energy usage and meter reading, and improved distributed and renewable resource interconnection.
- Operational benefits (and associated cost savings) from improvements in efficiency and system reliability, including reduced metering costs through automated metering and improved asset life through improved information on maintenance issues in wires or in substations, before equipment failures or outages occur.

To realize these benefits, it is important to understand the relationship between different technologies and the most cost-effective way to implement new technologies: for example, taking DER into account in distribution system planning to fully realize the benefits DER can provide to the GRID.

The PUC's primary objective here remains what it always has been: to ensure that Minnesota utility customers receive safe, reliable and affordable electric served. What has changed, however, is that now in order to meet that objective, all commissions must now ensure that utilities are planning effectively to accommodate penetration of DER, large-scale renewables and emerging technologies both in front of and behind the meter. Failure to do so will likely increase the costs of DER and renewable integration, missed opportunities to offset investments in distribution system upgrades with emerging technologies (such as electric vehicles) and ultimately increased bills for customers.

III. Response to Commission Questions

1) Evaluation of Utility Plans

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?

It would not make sense for CUB to be involved in short-term distribution system planning reviews. Stakeholders like CUB won't realistically be able to participate in annual plans in any meaningful way – and oftentimes utility distribution cycles are short such that they look at only year or two out, which is fine but can make it problematic to look at trends in DER, address whether DER can provide solutions to distribution system issues, etc. However, looking at trends in DER is a longer-term view than one or two years in many cases. The question becomes, is there room for stakeholders like CUB to be involved in those processes as DER becomes more substantial and could play a role in integrated resource planning ("IRP")?

As a result, one key question for the Commission is how long are the planning cycles involved – the length of time the plan covers, how frequently the PUC can do a meaningful review, and what the expectations are for the utility to follow the plan once approved (e.g. can they make mid-course corrections? If so, under what circumstances?) The Commission also must consider its ability to move through dockets, approving plans in a thorough but expeditious way – in other words, plans should only be reviewed in dockets with defined timelines for consideration. The Commission should not hamstring those investments which are cost-beneficial to customers with lengthy approval processes.

Similarly, the question of whether distribution system plans should be formally approved by the Commission depends on a few things, first and foremost what "approval" means in terms of cost recovery. CUB believes that approval of a plan should not be used to replace traditional Commission or use of legal standards like prudency/used and useful when reviewing utility rates.

Approval of a plan could be used to answer the first part of a prudency review – should the utility make these investments – though CUB would urge that the second part of the prudence review must be considered in the utility's rate case – how was the investment made and managed – before any cost recovery should be allowed. The Commission should avoid any situation where distribution plans are approved say, every other year, but rates are reviewed only every few years. If approval were to mean the utility recovers costs before/outside of the rate case, that is problematic. If approval simply means that conditional approval is given – conditional on the ultimate implementation and delivery of projected benefits – then approval of a utility's distribution system plan could be appropriate.

One alternative for the Commission to consider is the use of annual reporting by the utilities that follows standard guidelines, data requests and directives from the Commission. Costs and benefits could be reviewed in rate case proceedings, as they are now, but with annual reports as part of those proceedings to enable a broader discussion of how utility distribution system planning is advancing state policy goals.

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

A distribution system plan should include resource planning (the anticipation of changes in DER/load growth), which in turn includes review of interconnection procedures, hosting capacity, etc., which affect the energization of DER projects. Metrics should be assigned to show how the utility is planning for the integration of DER and other desired functionality over time:

- Customers enrolled in dynamic/time variant prices, net metering, etc.;
- Customer-side-of-the-meter devices sending or receiving grid related signals;
- Asset failures/replacements before the end of the asset's useful life – this includes meters, transformers, substations, etc.;
- Number of customer households with some device capable of receiving information from the grid;
- Peak load reductions, changes in load shape, etc. by as granular an area as possible within a utility's service territory;
- System load factor and load factor by customer class;
- Hosting capacity across the utility service territory;
- Amount of load served by DER;
- Number of DER projects connected and projected to be connected;
- Products with end-to-end interoperability certification;
- Number of network nodes and customer interfaces monitored in "real time;"
- Grid connected energy storage interconnected to utility facilities at the transmission or distribution system level;
- Time required to connect distributed resources to grid
- Voltage and VAR controls; and
- Number and type of grid assets that are monitored, controlled, or automated, along with number of customers connected per automated circuit segment.

Once these metrics are established and reported on, they can be used in any other utility proceeding and will provide a common framework for evaluating progress in grid modernization. Because grid modernization investments have a potential impact on load growth, distribution planning should be integrated with resource planning. At the same time, it is important to differentiate between long-term distribution system investments that may have impacts on DER and load growth and short-term investments. Including the large investments such as AMI in the IRP process would be beneficial and allow more room for groups like CUB to participate.

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?

This all depends on the frequency of plans, how willing parties are to handle confidential information to the extent that it is involved, what the Commission proposes to do with the plans, etc. In other words, if the plans become a formal docket, with a purpose of informing the Commission's review of projects and ultimately the utility's cost recovery, stakeholders will have a reasonable expectation that as much information will be shared as transparently as possible. The balance needs to be between the practical use of the plans, enough time for implementation of the plans and then collection of data, and then frequent enough review to ensure course corrections as needed – and the ability of stakeholders to meaningfully participate in terms of expert resources and time.

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

First and foremost, the Commission is looking at whether the plan advances specific benefits, incorporates over time more and more of the desired functionalities, and does so in the most cost-effective way possible. As noted above, CUB believes the Commission can do this not by becoming technical experts as much as by focusing on whether a given investment gives the utility one of the following abilities, all of which are necessary to the development of a modern distribution grid:

- The ability to develop, store, send, and receive digital information concerning or enabling grid operations, electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system through one or a combination of devices and technologies;
- The ability to develop, store, send, and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device;
- The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize, or report that information by digital means;
- The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations;
- The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices;
- The ability of any device or machine to respond to signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention;

- The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual;
- The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation; and finally,
- The ability to integrate electric plug-in vehicles, distributed energy resources, and storage in a safe and cost-effective manner on the electric grid.

The Commission should also look to see how the plan addresses issue of technology obsolescence – that is, the risk the utility invests in technology that is outdated or soon will be. A classic example in the utility world is the comparison between investing in AMR versus investing in AMI, and the subsequent cost to replace AMR with AMI if those benefits associated with AMI are desired.

In a similar fashion, the Commission should also look to see if the plan leverages use of existing infrastructure. While CUB can support grid modernization efforts, CUB also believes the utility should make the best of use of what customers have already paid for (or are paying for).

Finally, the Commission should make sure that load growth and load shape forecasting accurately reflects expected changes in DER penetration, customer response to pricing programs, electrification of transport, etc. Fundamentally, the goal of these investments should be to consider non-distribution alternatives – that is, whether or not DER can address system needs that previously would have been addressed only by investment in wires, poles or other utility capital assets.

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

Beyond the discussion above, CUB has no specific recommendation at this time.

2) Feasibility of planning enhancements.

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

What is most important is the Commission application of the same set of criteria to all plans with the understanding that each utility service territory is different, and as a result, how each utility fulfills the criteria should be expected to be different. Whether that application occurs through annual dockets, the setting of standard plan filing requirements, or some other means can be balanced by the need to ensure stakeholder participation and guard against the information asymmetry inherent in planning discussions (i.e., the utilities have the system planning data, and the PUC and stakeholders need that same data to evaluate the utilities' efforts).

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)

CUB has no comment on this question at this time.

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

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

All of these would be good additional data points for use in system planning. The odds of coincident failure of multiple DER assets implies some type of emergency situation (e.g. widespread damage to the grid such that assets are not connected or some natural disaster such that they cannot perform) and the impacts of that will depend on whether those assets are clustered or dispersed. Utilities already run such scenarios, as do regional transmission organizations ("RTOs"); the question is whether they have sufficient transparency into behind-the-meter generation for accurate scenario planning. More data can always improve planning, but at the outset, the Commission should focus on that data which is most useful to the Commission's role of ensuring distribution service, which is probably first and foremost forecast data. To be accurate, forecast data should also take into account the effects of efficiency and demand-side resources as well as changes in usage patterns (e.g. reductions in peak load).

4) Scenarios

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

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

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

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

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

All of these questions ultimately address how sophisticated the Commission feels its own analysis – that is, the analysis it directs of the utilities – needs to be compared to that done by federal agencies and RTOs. It may be more efficient to first compile what scenarios are already done, who they are shared with, and how much additional granularity needs to be added before answering these questions. A few basic scenarios could be mandated (assuming the Commission orders a distribution planning process), and they can be common across all utilities – while the results may be different, the scenarios can be the same. The very basic scenarios often involve growth scenarios (low load growth, moderate load growth, high load growth) and similar low/moderate/high penetration scenarios for DER. Again, these need to take into all types of resources, including efficiency investments and demand response programs.

There is no reason to recreate the wheel here if the Commission doesn't have to – doing so will only add expense for the utility which will ultimately be covered by customers. The further out in time a scenario looks, the less useful it probably is in specifically modeling outcomes. For a distribution utility, what is most likely to change rapidly is the deployment of DER – and as such, planning probably needs to be done on a tighter time frame than for transmission planning.

5) Standards.

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

At this time, CUB hasn't identified any additional standards/codes aside from those adopted within Minnesota and nationally to facilitate the integration of DER (e.g. NIST, IEEE, etc.).

6) Access to Grid and Planning Data by Customers and Third Parties.

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

As noted earlier, one of the challenges for Commissions in evaluating grid modernization efforts can be the role of third parties – that is, groups that are not the utility and not the customer, such as providers of DER solutions such as distributed generation. In many cases, squeezing extra efficiency out of a distribution system works against the business interests of vertically integrated, investor-owned utilities. Sharing distribution planning information with customers or third parties ultimately facilitates the integration of DER, reducing the need for ratepayer spending on utility infrastructure, and also the opportunities for utility capital investment. For this reason, and because third parties may be more nimble than utilities, informed third parties may achieve greater efficiency and cost-effective DER implementation than the utility alone.

Ideally, distribution system information is used to incent investment in DER in areas such investment can address system needs cost-effectively (e.g. for high values to utility, where distribution system upgrade not necessary to accommodate more solar). As a result, the answer to this question probably depends in part probably on whether these plans are reviewed in a formal setting or an informal one. In a formal one, third parties can be subject to confidentiality orders and other formal processes to manage any concerns regarding the sharing of information. In any event, CUB notes that any information deemed classified for reasons of national security obviously should be protected and shared only in a formal setting subject to the signing of strict protective orders.

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

There should not be any need to identify individual customer usage data such that there shouldn't be a need for specific customer privacy protections. Aggregated, anonymized data by circuit and feeder would be sufficient to look at usage patterns, load shape and ultimately hosting capacity. However, there are challenges to the deployment of DER which this question highlights. For example, how will the distribution utility know about the use of electric vehicles? Without "smart" meters, there's no way to disaggregate load – and there is no requirement to register an electric vehicle or put it on a special rate, so this will be an issue in two ways: evaluating if cars are charged in such a way that there could be an issue on a feeder if multiple cars charge at the same time, and missing an opportunity to identify batteries that can be used to flatten the load curve and support DER integration. From a

Commission perspective, is electric vehicle ownership the type of information that would be considered customer specific and as such, in need of protection from disclosure?

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

i. Participate in developing system plans

ii. Critically review proposed plans

iii. Prepare commercial projects in response to plans

"Commercial projects" in this context could refer to utilities' identifying DER projects or issues and asking for responses, or informing third-party developers of where DER projects would be valuable. CUB believes that in either case, hosting capacity, usage patterns, power quality data, forecast data, and other similar data would be useful.

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

CUB interprets "planning opportunities" to mean opportunities to integrate DER in response to an identified system needs. As such, a standard form identifying hosting capacity by as granular an area as possible might be sufficient. While distributed generation may be cost-effective for customers in some places on a utility's grid, in other places it may not be. Customers need to know whether they are in a good location for a distributed generation project without first evaluating a project, contacting a vendor, preparing an interconnection application, filing that application with the utility and waiting for a response. Utilities can address this problem by publishing information about its distribution grid on its website, for example, showing where the radial grid ends and where the network grid begins, an important distinction because of variations in the interconnection rules. This would include information on customer areas served by feeders that have already reached the threshold of distributed generation capacity necessitating a higher level of study. Nationally, utilities have published interactive distribution grid maps that provide customers with information that they can use to perform and initial screening of the best places to interconnect distributed generation.

For other stakeholders, and the Commission, it will probably be more important to have standardized plans and metrics reporting available in one place so that trends can be tracked over time by comparing plans/reports.

7) Hosting Capacity.

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?

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.

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

See above.

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

CUB has no comment at this time.

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?

CUB has no comment at this time.

Thank you for the opportunity to provide these initial comments. CUB looks forward to continuing the discussion with the Commission, utilities, and stakeholders.

Respectfully submitted, August 21, 2017

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