Minnesota Public Utilities Commission

Staff Report on Grid Modernization   March 2016

Executive Summary

In May 2015, the Minnesota Public Utilities Commission (Commission) initiated a proceeding to consider development of policies related to grid modernization with a focus on distribution system planning. The Commission held three workshops to gather information on distribution system planning and grid modernization, and to identify specific actions, technologies, and policies that could support and enable grid modernization. The Commission also sought two rounds of comments to support this effort. This report summarizes the actions in the proceeding to date, identifies aspects of the stakeholder comments identified as important for discussion of grid modernization, and proposes a process for continuing the development of policies related to grid modernization.

Specifically, this Report:

- Develops a definition of grid modernization for Minnesota;
- Identifies principles to guide the development of grid modernization in Minnesota; and,
- Proposes a three phase approach to continue policy development of grid modernization in Minnesota.

When combined, these three components will allow the Commission to identify and consider necessary policy development and implementation in a manner that best suits the needs of Minnesota. This process will provide ample opportunity for stakeholders to provide input in the process. Specifically, this report highlights the need for the Commission to: address distribution system planning in order to enhance grid reliability and resiliency; ensure optimal utilization of grid assets to minimize total system costs; and enable integration of a variety of distributed energy resources.

The needs, use, and expectations of the distribution grid are evolving as customer preferences change and as energy technologies increasingly become available directly to customers. Furthermore, as policy directives move Minnesota, the electric utilities and consumers toward adoption of cleaner and more distributed resources, the Commission may want to plan for these changes, consistent with the public interest. This report outlines a process that would allow the Commission to develop policies that plan for and meet these expectations in a way that maintains and enhances system reliability while enabling customer choice and supporting continued innovation.

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Table of Acronyms

Acronym	Meaning	For more information
AEE	The Advanced Energy Economy Institute	See its first and second comments
AMI	Advanced Metering Infrastructure	See Section 4.5
AMR	Automated Meter Reading	See Section 4.5
ARCs	Aggregators of Retail Customers	See Section 4.8
CEUD	Customer Energy Usage Data	See Section 4.7
CPP	Critical Peak Pricing	See Section 4.9
CVR	Conservation Voltage Reduction	See Section 4.6
DERs	Distributed Energy Resources	
DPU	Department of Public Utilities (Massachusetts)	See the Department's website
DG	Distributed Generation	
DSO	Distribution System Operator	See Section 5.1
DSP	Distribution Platform Providers	See Section 1.3
DVI	Dominion Voltage, Inc.	See its first and second comments
EPRI	The Electric Power Research Institute	See the Institute's website
FERC	The Federal Energy Regulatory Commission	See the Commission's website
IEEE	Institute of Electrical and Electronics Engineers	See the Institute's website
IOUs	Investor-owned Utilities	
IREC	Interstate Renewable Energy Council	See its first and second comments
IRP	Integrated Resource Planning	See Minn. Stat. §216B.2422
MP	Minnesota Power	See its first and second comments
NEC	U.S. National Electric Code	
OATI	Open Access Technology International	See its comments
O&M	Operation and Maintenance	
OTP	Otter Tail Power	See its comments
PBR	Performance Based Ratemaking	See Section 5.3
PTR	Peak Time Rebates	See Section 4.9
PV	Solar Photovoltaics	
REV	Reforming the Energy Vision	See Section 1.3
RTP	Real Time Pricing	See Section 4.9
TASC	The Alliance for Solar Choice	See its first and second comments
TOU	Time of Use	See Section 4.9
UL	Underwriters Laboratory	See its website
VVO	Volt/VAR Optimization	See Section 4.6

Section 1 | Introduction

Minnesota's electric utility distribution systems are the backbone of reliable, safe and resilient electric service for Minnesotans. These systems consist of large networks of wires, poles, transformers and control systems that provide electric services directly to customers' homes and businesses. Today, the function of these distribution systems are improving and changing, driven by forces such as rapid technological innovation, expanding customer interests and demands, and energy and environmental public policies.

In May 2015, the Commission initiated an inquiry into grid modernization, with a focus on distribution system planning. The focus of the Commission's inquiry is the evolution underway in Minnesota's electric distribution grid. The Commission aims to identify steps it could take to advance grid modernization to the benefit of Minnesota's electricity consumers. The Commission has solicited input from diverse stakeholders through a series of workshops as well as through written comments. This input will help guide the Commission as it considers future planning and operations of the distribution grid.

1.1 Grid Modernization

Definitions of grid modernization abound, and there is no single, universally recognized definition. The Energy Independence and Security Act of 2007 described it as "the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth" and to meet 10 characteristics or functions.[1] A modernized electric grid requires several technology types working in concert. The Department of Energy's[2] five main smart grid technology areas are: 1) integrated communications allowing for real-time information and control, 2) sensing and measuring technology supporting rapid and accurate system and human responses, 3) advanced components such as storage and superconductivity, 4) advanced control methods, such as voltage optimization, and 5) improved interfaces and decision support for distribution system managers.

Some examples of these technologies that are actively being deployed include advanced metering infrastructure, outage management with field devices, two-way communication networks, automated controls, and voltage regulation.

A concise definition of grid modernization that reflects the goals of Minnesota will provide a framework that will guide the Commission's approach grid modernization. As discussed in further detail in Section 3 of this report, Staff proposes the following definition to guide grid modernization in Minnesota:

> A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and

[1] Energy Independence and Security Act of 2007, Pub. L. 110-410, 42 U.S.C. § 17381 (link).

[2] U.S. Department of Energy, National Energy Technology Laboratory, "A Systems View of the Modern Grid," January 2007, at page 17 (link).

greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network

1.2 Grid Modernization Efforts in Minnesota

The Commission's grid modernization initiative

The Commission initiated its inquiry into grid modernization at a May 12, 2015 planning meeting. There, the Commission discussed the evolution of the distribution electric grid, some key drivers for further grid modernization, and related national and Minnesota-based work.

In summary, the planning meeting presentation and Commission discussion included the following key points:

- The electric distribution 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 new grid technologies and expanded deployment of a variety of distributed energy resources;
- Tomorrow's integrated electric grid will be more distributed and flexible; will be operated in concert with customer owned resources to optimize value; will operate resiliently against natural disaster and attacks. Development of tomorrow's grid is already underway, and investments are being made today that will influence the capabilities of the future grid;
- Updates to distribution planning process will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; new planning efforts should be coordinated with resource and transmission planning.

The Commission agreed to a framework for an inquiry into electric utility grid modernization, with a focus on distribution planning. Specifically, the Commission aimed to address three key questions to the right:

To investigate these questions, the Commission solicited written comments and convened three stakeholder meetings. Between the two rounds of written comments, received in September and

Three Guiding Questions for Minnesota

- 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?

November of 2015, the Commission received comments from twenty parties,[3] representing a diverse array of perspectives, including utilities, advocacy groups, state agencies, and technology vendors. These comments are available in eDockets.[4]

Three stakeholder meetings were convened in the fall of 2015, addressing the following topics:

- The September 25th meeting focused on Minnesota's electric utility distribution systems, with a discussion of the design, operations, performance, capability, and planning processes for existing distribution systems;
- The October 30th meeting examined national distribution grid modernization work and emerging best practices;
- The November 20th meeting considered stakeholder perspectives, giving interested parties an opportunity to provide feedback on current distribution planning processes and to suggest next steps for the Commission.

The meetings were open to all; attendance ranged from just under 100 to nearly 150 participants, including utility representatives, energy policy advocates, technology vendors, university professors and students, and legislative and state agency staff. The meetings featured several presentations from Minnesota utilities and national subject matter experts,[5] as well as stakeholder panels[6] and audience question and answer periods. Attendees provided a wide range of thought-provoking questions and comments.

A summary of the stakeholder meetings is included as Appendix A, and the PowerPoint presentations are available in eDockets.[7]

Additional grid modernization work in Minnesota

The e21 Initiative and the 2025 Energy Action Plan are two examples of work underway in Minnesota complementary to the Commission inquiry into grid modernization.

[3] Comments were submitted by: Advanced Energy Economy Institute, Bridge Energy Group, ChargePoint, Cooperative Energy Futures, Dakota Electric Association, Dominion Voltage, Energy Storage Association, Enernoc, Fresh Energy, Interstate Renewable Energy Council, Minnesota Center for Environmental Advocacy, Minnesota Power, the Office of the Attorney General, Open Access Technology International, Otter Tail Power Company, Renewable Energy Systems Americas, the Alliance for Solar Choice, the Mission: Data Coalition, Wind on the Wires, and Xcel Energy.

[4] To access these and other relevant documents, visit the Commission's eDockets website for Docket 15-556 (link).

[5] Presentations were given by: Brian Amundson (Xcel Energy), Steve Cook (Rochester Public Utilities), Rick Johnson (Otter Tail Power), Will Kaul (Great River Energy), Laura Manz (ICF International), Janine Migden-Ostrander (Regulatory Assistance Project), Reed Rosandich (Minnesota Power), Jeff Smith (Electric Power Research Institute), Damian Sciano (Consolidate Edison of New York), and Craig Turner (Dakota Electric Association).

[6] Panelists included: Carolyn Brouillard (Xcel Energy), Joseph Dammel (Office of Attorney General), Timothy DenHerder-Thomas (Community Power), Jenny Edwards (Center for Energy and Environment), John Farrell (Institute for Local Self-Reliance), Carlos Gonzalez (Solar City), Daniel Gunderson (Minnesota Power), Bill Grant (Department of Commerce), Ali Ipakchi (Open Access Technology International), David Kolata (Illinois Citizens Utility Board), Holly Lahd (Fresh Energy), Jeremy Laundergan EnerNex), Rolf Nordstrom (Great Plains Institute), David O'Brien (Navigant), Hannah Polikov (Advanced Energy Economy), Larry Schedin (Minnesota Chamber of Commerce), Jeffrey Schoenecker (Dakota Electric Association), Maria Seidler (Dominion Voltage), Beth Soholt (Wind on the Wires), Sky Stanfield Interstate Renewable Energy Council), Lise Trudeau (Department of Commerce), Curt Volkmann (Fresh Energy), and Jason Willets (Metropolitan Council).

[7] To access these and other relevant documents, visit the Commission's eDockets website for Docket 15-556 (link).

Under the guidance of the Legislative Energy Commission and the Minnesota Department of Commerce, the 2025 Energy Action Plan aims to, "[d]evelop indicators and action plans to significantly advance a number of strategies and technologies for clean, efficient energy in Minnesota between now and 2025" and to "develop recommended next steps to leverage near-term opportunities for a clean, affordable, reliable, and resilient energy system."[8] Grid modernization is one of the project's five primary areas of focus.

Convened by the Great Plains Institute, Center for Energy and Environment, Energy Systems Consulting Services, George Washington University Law School, Xcel Energy, and Minnesota Power, the e21 Initiative "aims to develop a more customer-centric and sustainable framework for utility regulation in Minnesota that better aligns how utilities earn revenue with public policy goals, new customer expectations, and the changing technology landscape."[9] The e21 Initiative has developed subgroups for three subject areas, one of which is grid modernization.

Recent legislative directive

In the 2015 Special Session, Governor Dayton signed new legislation[10] related to grid modernization and distribution planning. The amendments, which apply only IOUs operating under a multi-year rate plan, incorporate distribution grid modernization investment and planning issues into the existing biennial transmission plan filing requirements. Specifically, the utility is to:

- [I]dentify investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies; and
- [C]onduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources.[11]

Currently, only one utility, Xcel Energy, is operating under a multi-year rate plan. Xcel Energy filed its first Grid Modernization Report under the legislation on October 30, 2015. The Report was filed in Docket 15-962. By law, the Commission must take action on this Report by June 1, 2016. More information on the Report can be found in eDockets.[12]

1.3 Grid Modernization Efforts Around the U.S.

In recent years, several states have pursued grid modernization. Here, Staff briefly summarizes the efforts of three leading states: Massachusetts, California, and New York.

[8] See the 2025 Energy Action Plan's project website: http://www.lec.leg.mn/projects/2025.html

[9] e21 Initiative, Phase I Report. More information on the Initiative (including the Phase I Report) can be found at the project website: http://www.betterenergy.org/projects/e21-initiative

[10] House File 3 of the 2015 Special Session, approved on June 13, 2015, modifying Minn. Stat. §216B.2425.

[11] Minn. Stat. §216B.2425, Subd. 2(e) and Subd. 8 (link).

[12] See the Commission's eDockets website for Docket 15-962 (link).

In an October 2012 Order,[13] the Massachusetts Department of Public Utilities (DPU) officially began its inquiry into grid modernization. After conducting a stakeholder engagement process, the DPU issued an order requiring each utility to submit a ten-year grid modernization plan, outlining its priorities for grid modernization planning and investment. Specifically, utilities were directed to focus on four objectives: "(1) reducing the effects of outages; (2) optimizing demand, which includes reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management."[14] The DPU also required utilities to investigate Advanced Metering Infrastructure (AMI) and time-varying rates.[15] In August of 2015, several major utilities filed their grid modernization plans.

In California, state legislation passed in 2013 required electric corporations to file distributed resource plan proposals with the California PUC. With the help of the More Than Smart Initiative, the CPUC then issued guidance on the components to be included in the plans. The More Than Smart Report developed the guiding principles for distribution planning listed below.[16] On July 1, 2015, six utilities filed Distributed Resource Plan Applications.

More than Smart's guiding principles (California)

1) Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources.
2) California's distribution system planning, design and investments should move towards an open, flexible, and *node-friendly network system* (rather than a centralized, linear, closed one) that enables seamless DER integration.
3) California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest.
4) Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.

Grid modernization and distribution planning is also a part of New York's ambitious "Reforming the Energy Vision" (REV) initiative. A 2015 New York PSC Order[17] outlined the REV framework, including reimagining utilities as Distribution Platform Providers (DSP) with three functions:

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[13] Massachusetts Department of Public Utilities, October 2, 2012 Order in Docket 12-76 (link).

[14] Massachusetts Department of Public Utilities, June 12, 2014 Order in Docket 12-76, at page 2 (link).

[15] AMI and time-varying rates are discussed in Sections 4.5 and 4.9 of this Report, respectively.

[16] DeMartini, Paul, "More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient," August 2014, at pages 3-4 (link).

[17] New York Public Service Commission, "Order Adopting Regulatory Policy Framework and Implementation Plan," issued February 26, 2015 in Case 14-M-0101 (link).

integrated system planning, grid operations, and market operations. DSPs will be required to regularly file multi-year Distribution System Implementation Plans with the NY PSC, subject to public comment. In October 2015, NY PSC staff provided guidance on the contents of the DISPs, setting a June 30, 2016 deadline for initial filings.[18]

1.4 Commission Approach to Grid Modernization

After decades of relative tranquility, the electric industry is encountering major changes. The large, steady load growth of the twentieth century has been eroded by energy efficiency, conservation, and macroeconomic factors. The rise of electronics and access to and utilization of energy use data has elicited changes in customer expectations. As aging distribution infrastructure approaches the end of its useful life, emerging technologies promise enhanced functionalities and operational efficiencies. Technological and manufacturing advances have driven down the costs of distributed renewable resources and battery storage.

These changes will continue with or without Commission action. Aging infrastructure will need to be replaced, distributed energy resources will expand as costs fall, advances will be made in distribution system technology, and customer demands will continue to evolve. The threshold question facing the Commission is: how can forward looking planning targeted at the distribution system level, in coordination with other planning (IRP, transmission, etc), be effectively and appropriately accomplished in order to protect and promote the public interest. To date, the Commission has addressed subsets of these issues as they have arisen, supplemented occasionally with information gathering. By launching this inquiry, the Commission recognizes that a more directed and coordinated approach to grid modernization is warranted. This approach was reinforced through stakeholder meetings and comments.

Factors driving change

Interest in grid modernization has been driven by a confluence of factors, including aging infrastructure, rapid technological advances and cost declines, changing customer demands, and emerging public policies.

In stakeholder meetings and comments, several parties voiced concerns about aging distribution and substation infrastructure. In Dominion Voltage, Inc. (DVI)'s words, "For the most part, the energy delivery systems throughout the U.S. are characterized by an aging infrastructure, utilizing technology developed in the 1950s or earlier. One of the drivers of grid modernization is the update of this aging infrastructure and replacement of outdated technology."[19] This was a common theme of the presentations in the first stakeholder meeting, mentioned by the distribution engineers from each of the state's IOUs. As Table 1.1 displays, the average distribution asset age was roughly 35 years for Minnesota Power, 40 years for Otter Tail, and between 20 and 40 years for Xcel.[20] Annual

[18] New York Public Service Commission, "Staff Proposal: Distributed System Implementation Plan Guidance," filed October 15, 2015 in Case 14-M-0101 (link).

[19] Dominion Voltage, Inc., November 18, 2015 Comments, at page 1 (link).

[20] The safety of existing infrastructure, including asset management, maintenance, and replacement schedules may warrant additional attention, especially as utilities seek to install advanced technologies across their distribution grid. While not specifically included in this Report, ensuring the safety of the existing distribution grid should not be forgotten in this process.

distribution spending has also increased both in Minnesota and nationally: in 2014, Minnesota's IOUs invested over $200 million in their distribution systems.[21]

Table 1.1, Distribution System Summary Statistics by Utility

	# of Sub-stations	Distribution Feeders	Distribution Customers	Distribution Peak	Average Asset Age
Dakota Electric	30	164 feeders 4.5k miles 12.5 kV	104,000	500 MW	
Minnesota Power	317	4.5k miles OH 1.5k miles UG	142,700	690 MW (1,817 MW system peak)	35yrs – poles (also median age of system)
Otter Tail Power	500	730 monitored 4.5k miles OH 1.5k miles UG 2.4 - 25 kV	130,000	652 MW (Summer) 840 MW (Winter)	41yrs – OH distribution 38yrs – UG distribution
Rochester Public Util.	9	181 miles OH 528 miles UG	51,000	292 MW	
Xcel Energy	228	1,116 feeders 16k miles OH 9.5k miles UG 4 - 34.5 kV	1,200,000	~7 GW	20yrs (UG) to 40yrs (OH tap)

Source: September 25, 2015 meeting presentations. OH = Overhead; UG = Underground.

At that same time that new investments are planned to update grid infrastructure, there has been a notable decrease in costs for many distributed energy technologies. Perhaps the most visible are the widely-reported declines in the cost of solar photovoltaic (PV) installations: from 2009-2014, the average installed price for a PV installation fell by 13% *annually* for residential and 18% for large commercial installations; in total, the average installed cost for a residential installation in 2014 was just half of what it was in 2009; for large commercial installations, installed costs fell by almost two-thirds.[22] There have also been significant technological advances and cost declines for other distribution system technologies, such as monitoring and control equipment, data management software, and power electronics, just to name a few.

During this time, utilities have also seen increasing customer engagement. Customers have demonstrated more interest in their electric consumption, which can been seen from the proliferation of smart thermostats, commercial building automation systems, development of commercial building benchmarking efforts to support energy efficiency, and dynamic industrial demand response, to name a few. Customers have also taken more interest in the sources of their electricity, evidenced by customers' and utilities' interest in green tariffs. In a world increasingly dominated by electronics, there have also been calls for reliability and power quality improvements.

[21] Source: Compiled by Staff from Minnesota IOUs' 2014 FERC Form 1 filings. For a detailed discussion of distribution investments nationally, see the U.S. Department of Energy's April 2015 Quadrennial Energy Review (link).

[22] Barbose et al. "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," *Lawrence Berkeley National Laboratory*, August 2015 (link).

In a panel discussion at the first workshop, the Minnesota Chamber of Commerce stated that even a 20 second voltage drop can completely stop the production of an entire factory. This highlights the increasing economic value of electricity: former MISO chairman Paul Feldman estimated the economic cost of electric outages in 2013 was $112 billion, or roughly one-third of the total amount paid for electric service that year.[23]

Commission approach to grid modernization

There are a number of dockets that pertain to grid modernization. One notable example is the "Smart Grid" Docket (08-948), which required annual informational filings and included a series of topical workshops. There is considerable information in that docket about the utilities' then-current planning, distribution system investments, and time of use rate offerings.[24] The Commission has also addressed issues such as alternative rate design (Docket 15-662) and third party aggregation of distributed energy resources (DERs) (Docket 09-1449).[25] Continuing on this path—addressing issues piecemeal as they arise, possibly supplemented occasionally with information gathering—would be the simplest, least resource-intensive way for the Commission to proceed.

Several parties are advocating for a deliberate, holistic approach to grid modernization that would benefit Minnesota's utilities and customers. At the third stakeholder meeting, Fresh Energy argued there is a cost of inaction to installing distributed solar without smart inverters. The Department of Commerce expressed a similar concern, pointing to missed opportunities for energy efficiency and peak load reduction. In written comments, the Interstate Renewable Energy Council (IREC) cited additional costs of inaction: "rate pressure due to aging infrastructure replacements, price volatility due to declining fuel diversity, potential for utility revenue erosion as more energy consumers adopt DER, etc."[26]

In the Attorney General's words, "Even today, investments in new technologies, designed to make the grid more efficient, more resilient, or less carbon-intensive, are being made across the system. Without an overarching policy guiding these investments, it is impossible to ensure that they are—and will be—made in a cost-effective manner."[27] DVI[28] and IREC[29] expressed similar sentiments. Other parties argued for the importance of taking a holistic approach: in the third stakeholder meeting, the Department of Commerce expressed concern about the dangers of addressing grid modernization piecemeal, even given the current regulatory "bandwidth limitation."

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[23] Feldman, Paul J., "A Huge Distribution Opportunity," *Electricity Policy*, February 2015 (link). See also: Sullivan et al., "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," *Lawrence Berkeley National Laboratory*, January 2015 (link).

[24] This docket was closed when the Grid Modernization docket was initiated.

[25] These topics are addressed in Sections 4.9 and 4.8 of this report, respectively.

[26] Interstate Renewable Energy Council, November 18, 2015 comments, at page 4 (link).

[27] Office of the Attorney General, September 15, 2015 comments, at page 1 (link).

[28] Dominion Voltage, Inc., November 18, 2015 comments, at page 1 (link).

[29] Interstate Renewable Energy Council, November 18, 2015 comments, at page 4 (link).

The Electric Power Research Institute (EPRI) notes that "Distribution planners are facing a new reality: the vast majority of new generation currently being connected to the grid is through the distribution system… to meet these challenges, an integrated approach for planning is needed."[30]

Each of the state's IOUs also called on the Commission to take a more active approach to grid modernization. Otter Tail Power (OTP) argued that "clarity within the regulatory environment will ensure proper cost recovery for prudent grid modernization activities."[31] Minnesota Power (MP) called on the Commission to "define expectations for utilities" and to "create a roadmap that includes flexibility" to acknowledge the differences in the state's service territories.[32] Xcel expressed similar sentiments:

> There is also misalignment between the pace of technological change and regulatory change, with regulatory change lagging. Taken to the extreme, the slower action on the regulatory front could jeopardize utilities' access to low-cost capital, which could increase costs, hamper investment, and stall progress.
>
> As a result, we believe it would be very useful to identify specific policy goals and affirm a constructive regulatory and ratemaking framework that will help meet those goals, as well as facilitate investment, promote responsible innovation, and better match how customers are using and will use the system with how costs are recovered.[33]

1.5 Statutory Directives Related to Grid Modernization

These comments highlight the multifaceted interest the Commission has in the issues that fall under the umbrella of grid modernization. One need look no further than the introductory section of Chapter 216B, adopted when the legislature expanded rate regulation to electric utilities in 1974:

> It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers.[34]

This one sentence touches many of the possible benefits extoled by grid modernization proponents. The statute begins with reliability, a theme that recurs throughout Minnesota's statutes.[35] Several

[30] Smith, Rylander, Rogers, Dugan, "It's All in the Plans: Maximizing the Benefits and Minimizing the Impacts of DERs in an Integrated Grid." IEEE Power & Energy Magazine March 2015 (link); and Jeff Smith presentation at the October 23, 2015 workshop.

[31] Otter Tail Power, September 15, 2015 comments, at page 2 (link).

[32] Minnesota Power, November 18, 2015 comments, at page 2 (link).

[33] Xcel Energy, November 18, 2015 comments, at page 4 (link).

[34] Minn. Stat. §216B.01 (link).

[35] See, e.g. Minn. Stat. §§ 216B.029 (link), 216B.1611 (link), 216B.164 (link), 216B.2425 (link), and 216B.243 (link).

parties touted the potential for grid modernization investments to improve resilience and power quality. In Xcel's words:

> The modern grid will be more reliable and disturbances will be shorter and impact fewer customers. We will have heightened awareness about the current behaviors and health of the grid due to the intelligent devices in the field that are able to sense and adjust power flow, as well as provide intelligence on the current status at local points on the grid. Automation of certain parts of the system will allow the grid to dynamically respond to adverse conditions and restore portions of the system without human intervention. Additionally, when we do have outages, the grid will provide a more accurate understanding of exactly who is out of power and possible fault locations enabling quicker and more efficient outage response.[36]

The statute goes on to address "reasonable rates" and avoiding "unnecessary duplication of facilities which increase the cost of service." Several parties cited the potential for grid modernization investments to reduce system costs through more efficient use of resources: DVI advocated for deploying supply-side resources to improve energy efficiency of the grid; the Advanced Energy Economy (AEE) Institute promoted the use of customer engagement and Demand Response to optimize demand and improve utility capital asset utilization; and the Alliance for Solar Choice (TASC) emphasized the importance of both leveraging customer and third-party capital in order to reduce long-term cost and using economic signals to maximize the locational value of DERs.

Many parties also emphasized the potential for "non-wires" alternatives to mitigate the risk of system overbuilds and stranded assets that can result from traditional distribution system investments. In its initial comments, Fresh Energy pointed to Consolidated Edison's Brooklyn-Queens Demand Management Program in New York City. In his presentation at the second stakeholder meeting, Con Ed's Director of Distributed Resource Integration, Damian Sciano, elaborated on the project: when system growth prompted the need for a new substation, the utility was able to defer the investment by deploying a portfolio of distributed resources. The $200 million investment avoided the projected $1.2 billion in traditional network upgrades. Dr. Sciano emphasized what a dramatic departure this was from traditional distribution system planning. He explained that typical practice among distribution engineers is to over-build the distribution system, which is simpler and more predictable, but, as this example demonstrates, can lead to much larger investments than necessary. Notably, state statutes require utilities, when constructing a Large Energy Facility—either a large high-voltage transmission line or large generating facility—to evaluate "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency … load-management programs, and distributed generation."[37]

Beyond the introductory paragraph of §216B.01, there are many additional statutory directives relevant to grid modernization. The state's Cogeneration and Small Power Production statute is intended "to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public"[38]; several parties have cited

[36] Xcel Energy, November 18, 2015 comments, at pages 2-3 (link).

[37] Minn. Stat. §216B.243, Subd. 3(6) (link).

[38] Minn. Stat. §216B.164 (link).

the advancement of DG as a major policy objective for grid modernization and the integration of DG has been the primary focus of the grid modernization efforts in California and Hawaii.

There are also several statutory provisions aimed at reducing the state's greenhouse gas emissions: the state has set ambitious greenhouse gas reduction targets of 15% below 2005 levels by 2015, 30% below by 2025, and 80% below by 2050[39]; the "reasonable rate" statute requires the Commission to set rates to encourage energy conservation and renewable energy "to the maximum reasonable extent"[40]; and the energy savings policy goal states that cost-effective energy savings "are preferred over all other energy resources" and "should be procured systematically and aggressively."[41] Virtually all parties have mentioned the potential for distributed renewable generation to reduce the carbon intensity of our generation mix. A number of parties have also touted the potential energy efficiency improvements—on both the supply and demand side—through grid modernization.

Section 2 | Proposed Approach to Grid Modernization

2.1 Three-Phased Approach

The next step in the Commission inquiry is to develop a strategy to address grid modernization.

Staff proposes a three-phase process for consideration of grid modernization strategies that will guide the rest of this report. A three-phase approach would allow the Commission to take an organized and thoughtful approach to development of grid modernization policies and review of specific utility actions. The three phases are:

Phase 1 adopt definition, principles, and objectives for grid modernization

Phase 2 prioritize potential action items

Phase 3 adopt long-term vision for grid modernization (no immediate action)

Adoption of a three-phase approach will put the Commission in a position to logically and thoroughly vet the many considerations related to grid modernization and organize them in a way that the Commission, Commission Staff, utilities, and stakeholders can handle efficiently.

2.2 Overview of Phase 1: Adopt Definition and Principles

In the first phase, the Commission would adopt definitions, principles, and objectives for grid modernization. In Section 3 of this report, Staff offers a definition of and guiding principles for grid modernization. The adoption of guiding principles will provide a firm foundation for future planning around grid modernization and help guide the remaining two phases.

[39] Minn. Stat. §216H.02 (link).

[40] Minn. Stat. §216B.03 (link).

[41] Minn. Stat. §216B.2401 (link).

2.3 Overview of Phase 2: Potential Action Items

In the second phase, the Commission would direct additional study on a select number of items for on-going discussion. In Section 4 of this report, Staff provides a list of possible action items identified by stakeholders in the workshops and comments. The variety of items identified in Section 4 is indicative of the far-reaching impact of grid modernization across the utility and customer landscape. A few of these items are currently the subject of open proceedings—such as data privacy and data access and time-varying rate design—and Staff recommends that where an item is already the subject of an open proceeding, that proceeding should remain open and be allowed to continue its on-going work. Finally, the action items identified in Phase 2 would not be affected by future decisions regarding the longer term role of the utility in Phase 3.

In Section 4, Staff identifies nine specific actions that parties identified as important for the Commission to consider in the near term. These items are organized to: 1) reflect specific items that warrant greater consideration, 2) identify technologies raised throughout the proceeding by parties that support grid modernization, and 3) identify several policy-related decisions that may impact grid modernization. In this phase, the Commission would not be guaranteeing cost recovery for utility investments in those items, or making any other determination other than that the Commission, utilities, and other stakeholders should continue to discuss specific items that support grid modernization. The end result of that discussion could be an application by a utility to implement one or more of the items, which would still be subject to a cost-effectiveness review. Additionally, Staff recognizes each IOU is different; therefore, any actual implementations would be guided by what is more appropriate for that utility.

2.4 Overview of Phase 3: Long-term Vision for Grid Modernization

In this phase, the Commission would consider longer-term policies associated with issues related to long-term role of the regulated electric company relative to the role of customer or third party owned resources. Potential topics in this phase could include the evolving regulatory model for Minnesota, changes to the utility business model, changes to other existing programs, and consideration of whether the utilities should transition to distribution system operators. Action on these issues could be considered after Phase 2 is underway.

As more fully discussed in Section 5, several parties argue that DER will continue to proliferate, which will eventually cause impacts on the distribution grid. As these impacts grow, ensuring a stable revenue base of the regulated electric utilities, enabling additional benefits to customers, and supporting innovation and market growth will challenge the existing utility business model and regulatory model overseeing the regulated electric companies. Since this is a complex discussion that will require careful consideration, Staff recommends it be considered separately from (and following) Phase 2, which will have a more narrow focus.

Section 3 | Phase 1: Adopt Definition and Principles

In both workshops and written comments, several parties encouraged the Commission to begin its consideration of grid modernization by identifying definitions, principles, and objectives. In the second round of written comments—filed between the second and third stakeholder meetings—the Commission sought additional comments on the topic of principles and objectives for grid modernization. These comments provide the foundation for Staff's recommendations below.

3.1 Definition of Grid Modernization

In this docket, stakeholders provided the Commission with a variety of perspectives as to what "grid modernization" entails. The sheer number of options, varieties, and emphases makes it challenging to propose a single definition of grid modernization; however, staff believes developing a definition that reflects the goals and objectives of Minnesota will ensure the Commission, utilities, and stakeholders have a common understanding of how the Commission will approach grid modernization. Therefore, Staff proposes the following definition to guide further discussion on grid modernization in Minnesota:

> A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network

This definition captures the evolution of grid functions that are shifting from the one-way, radial approach of the current electricity grid into a more two-way and dynamic network. This network approach to the electricity system establishes potential new roles for the customer, the utility, the regulator, and the market. However, this definition does not preclude any role for the existing distribution utility, nor does it assume any potential restriction on the role of the utility. Rather, in keeping with the phased approach proposed by Staff, this definition recognizes the evolution occurring in the industry today and does not presuppose any broader, long-term policy preferences of the Commission.

3.2 Guiding Principles for Minnesota Grid Modernization

While there is value in developing a definition for grid modernization, perhaps the more important aspect of Phase 1 is the establishment of the principles to guide the investigation going forward. This was a nearly universal recommendation. In the second round of written comments, Staff asked parties what actions the Commission should take in the near-, mid-, and long-term. Virtually all commenters recommended the establishment of guiding principles as a near-term action item. In the second stakeholder meeting—which brought in national experts to discuss emerging best practices—each of the four presenters urged the Commission to begin by setting goals and objectives.

Through the workshops and written comments, parties and stakeholders offered a multitude of possible principles and objectives. Some of these have universal support. For example, all stakeholders acknowledge the critical importance of ensuring the safety of lineworkers. Others, such as transparency and access to data, are clearly needed but do not yet have universal support.

Seemingly similar objectives can have considerably different implications depending on how they are framed. For example, many parties offered objectives that relate to DER, but in markedly different ways: the Massachusetts DPU's objective of *integrating* DER may suggest a more passive role, while Cooperative Energy Futures' objective of a*ccelerating* adoption of DER suggests a more active role. Others, like EPRI emphasized maximizing *locational value* of DER, and yet others—like Xcel—would provide opportunities for *utility ownership* of DER. These four objectives would support very different action plans; this underscores the importance of being deliberate in the identification of principles.

Based on the commission discussion at the initial planning meeting in May 2015, the written comments submitted by stakeholders in Fall 2015, and the presentations and extensive discussions with workshop participants in Fall 2015, the following principles are recommended for consideration by the Commission. As stated earlier, the purpose of establishing principles is to provide additional guidance and clarification as the Commission continues its work in grid modernization. While the principles can serve as guidance for the Commission, they are not proposed as a framework for regulatory decision-making:

Principles for Grid Modernization at the Minnesota Commission

- 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;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

Section 4 | Phase 2: Potential Next Steps

Through stakeholder meetings and written comments, parties offered numerous potential next steps. Below, Staff summarizes the most common recommendations. While each of these options has merit, Staff notes that they come at a time when the Commission and Department are facing a daunting workload; it would not be possible to pursue all of these recommendations, at least not concurrently. Staff encourages commissioners to bear this in mind as they review the next steps. It is imperative to proceed strategically, prioritize Commission activities, and develop timelines that will optimize the use of scarce regulatory resources.

Some next steps could be considered either separately or combined as a larger vision. For example, questions related to advanced meters or hosting capacity analyses could be considered either on their own, or as sub-sets of a larger distribution grid plan. Further, some possible items are currently being addressed by the Commission in some form. For example, the current proceeding on customer data privacy (Docket 12-1344) is already looking at developing privacy framework for customer usage information, and may consider additional data access policy development. Additionally, the action item on revisiting Commission policies on third party aggregation may be better suited for the proceeding where those decisions were previously made (09-1449). These items are organized by focus area.

A. Items for Near-term Consideration

The following items have been identified by stakeholders and Staff as key next steps in the continuing discussion on grid modernization. These are the items Commission Staff identifies as most integral for continued development of grid modernization activity.

4.1 Integrated Distribution Planning

The topic of this proceeding to date has been grid modernization with a focus on distribution planning. In launching this inquiry, the Commission acknowledged at the outset that planning efforts will be an integral part of a systematic approach to grid modernization. The Commission has not yet developed a framework for how that planning should proceed and by whom. The engagement of stakeholders on this topic has been helpful to Commission. Parties provided a variety of comments on best practices, existing practices, and discussions on future role of distributed energy resources (DER) in Minnesota and identified that some form of additional distribution grid planning will be necessary to accomplish efficient integration of DERs. The utilities discussed their existing processes for distribution planning and how they envision these planning efforts will change going forward. Others, such as Fresh Energy and TASC, outlined alternative grid planning scenarios utilizing an increased amount of non-utility and distributed energy resources. Comments from IREC and TASC outline a revamped planning process, which includes a greater role for DER and necessary updates to the interconnection process to facilitate this effort. Other commenters, such as ChargePoint, point out the availability of a wider variety of resources, such as electric vehicles or energy storage, and the possible adverse effects on the grid without adequate planning.

Possible next steps

Regardless of the pace of change and customer adoption of new technologies, a distribution grid planning effort is an integral part of the evolution of the distribution grid. Hawaii is often called "a postcard from the future," demonstrating the increasing difficulties utilities face with increasing penetrations of DER. Beginning a distribution planning effort now would allow the state to prepare for and avoid future disruptions. Utilities and stakeholders would be able to begin building in the necessary technologies, functions, and requirements proactively, rather than reactively. Appropriate planning will also ensure that the distribution grid investments that are being made today will serve the purposes of the future grid and fulfill consumers' evolving needs.

This proceeding has provided valuable insight into the capabilities of the existing grid, the needs of the grid for integrating DER, and emerging best practices for distribution planning. However, these topics are both broad and deep; Staff believes further inquiry is necessary if the Commission is interested in establishing planning requirements for the distribution grid. For example, future Distribution Grid Plans would likely include at least one, if not all, of three main areas: scenario planning[42] analysis, hosting capacity analyses (Section 4.4), and increased access to distribution grid data. It could also include some of the other possible action items listed below.

4.2 Smart Inverters

To many, smart inverters are a key component of efficiently and reliably integrating DER with the distribution grid. Unlike other types of electricity generation, solar PV produces direct current power; inverters then change the current to alternating current to allow the electricity to be sent over the distribution grid. Inverters are increasingly being outfitted with new software that can respond to grid needs by providing, for example, volt-VAR support, islanding, and on-site use.

To date, the majority of interconnection tariffs rely on standards that do not support this advanced inverter functionality. In the United States, IEEE 1547 and UL 1741 do not allow for this functionality to be activated, mostly in the name of safety. For example, when the power goes out in a neighborhood the lineworkers dispatched must be sure that there is no current flowing through the lines. The standards in place today require all distributed generation to shut down during an outage; this shut down deprives the customer of on-site electricity, and it deprives the utility of a local source of black start or voltage support.

During its recent update of its interconnection tariffs, California took a new look at requiring smart inverters for all new distributed generation that seeks to interconnect with the distribution system. The California Rule 21 stakeholder group worked with IEEE and UL to create an update to the existing standards within its larger revision to the standards. Upon the completion of the revision to UL 1741, which is expected this year, smart inverters will be required for all new solar PV installations one year after approval of the standard.[43] Lastly, California began to consider appropriate communication standards between the networked grid and the inverter; standards it reviewed included Smart Energy Profile 2.0, IEC 61850, and IEC 61970.

Xcel report

In response to this work on smart inverters, the Commission directed Xcel to prepare a report on smart inverters and its application for community solar gardens.[44] In the report, Xcel described the basics of smart inverters and their functions, how smart inverters are used in solar applications, certification requirements for smart inverters, how smart inverters are used in Xcel's system, and safety and reliability concerns with smart inverters.[45] The report notes that current Minnesota interconnection tariffs utilize versions of UL 1741 and IEEE 929[46] that do not allow advanced inverter

[42] For example, one scenario would analyze a high DER future—what would that look like to the grid operator, how could the grid operator respond if DER were clustered, and how would the grid operator start to differentiate between types of DER, both in grid planning needs, but also in identification of grid needs. This scenario planning could also help identify any necessary changes to existing tariffs, as well as technological needs for the grid.

[43] For more information on California's Rule 21 effort, see http://www.energy.ca.gov/electricity_analysis/rule21/. The web page contains the technical reference materials used by the working group to update California's Rule 21, notes from all meetings of the working group, and additional background information.

[44] Minnesota Public Utilities Commission, *Order Rejecting Xcel's Solar-Garden Tariff Filing And Requiring The Company To File A Revised Solar-Garden Plan*, April 7, 2014 (link).

[45] Xcel Energy, Smart Inverter Report, filed September 1, 2015 in Docket 13-867 (link).

[46] IEEE 929 is no longer the applicable standard as IEEE 1547 has now superseded it.

functions to be activated when solar PV "actively interacts with the grid."[47] Xcel does note that it is planning to integrate smart inverters, but is waiting for the completion of the IEEE 1547 and UL 1741 updates.[48]

Stakeholder Comments

The topic of smart inverters came up frequently in the stakeholder meetings. EPRI noted that, depending on the location, smart inverters can double the amount of DER that can be reliably integrated onto the grid. Xcel noted the potential for smart inverters to provide reactive power support. Fresh Energy cited smart inverters as an example of the cost of inaction, noting that Minnesota is poised to connect over 100 MW of solar PV on the distribution system in the near future; if smart inverters are not installed initially, expensive retrofits will be required down the road.

Possible next steps

Due to the importance of the functionality enabled by smart inverters, the Commission should monitor the progress on the finalization of the standards supporting smart inverters. In the meantime, the utilities need not wait for the completion of the standards to start developing procedures for accepting smart inverters and their associated functionality into its system. This can include identification of the services that smart inverters can enable on the distribution grid to enhance reliability and resilience. This may be done through the development of pilots or pro-actively working with existing DER to start enabling smart inverter functionality on a rolling basis. Additionally, more work needs to be done identify an appropriate communication standard to support the communications with the smart inverter. This communication standard should be interoperable across third party networks and with the utility's own networks and other infrastructure.

The Commission also has several options for considering the topic of smart inverters: it could be considered as part of a distribution system plan (Section 4.1), a review of the Interconnection Order (Section 4.3), or on its own.

4.3 DG Interconnection Order

The September 28, 2004 Order in Docket 01-1023 (The Interconnection Order) was the culmination of a three-year effort, led by the Commission with extensive stakeholder involvement. Directed by legislation[49] to develop generic interconnection standards, the Commission engaged stakeholders through a series of written comments and work groups. In total, the Commission received input from over thirty parties. After the Order was issued, all electric utilities were required to adopt DG tariffs that addressed the issues included in the Order.[50] The Order has been the guiding document for DG interconnections ever since.

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[47] Xcel Smart Inverter Report at 6.

[48] Xcel Smart Inverter Report at 8.

[49] Minn. Stat. §216B.1611, Subd. 2 (link).

[50] Per Subd. 3 of §216B.1611, the state's IOUs were required to file tariffs that were "consistent with" the Order, while each municipal and cooperative utility was required to adopt a DG tariff that "addresses the issues included in the commission's order."

Stakeholder comments

Several parties encouraged the Commission to review its interconnection process. Fresh Energy, IREC and TASC raised the issue repeatedly during the stakeholder process. Other parties—such as AEE and The Mission: Data Coalition—endorsed a review in written comments, and ICF International and the Regulatory Assistance Project each mentioned it in their presentations at the second stakeholder meeting.

According to TASC, "[t]wo aspects are foundational to initiate [interconnection] modernization: 1) enable a transparent, timely interconnection application approval process, and 2) consider alternatives to the typical utility mitigations, which require costly equipment upgrades."[51] TASC campaigned for a streamlined interconnection process with more access to basic grid data. This would include a simplified screening for less complex interconnections. And if a project needs a more in-depth review, in TASC's vision the developer would be more involved in the review: if they were provided with more information about the limiting factor of the circuit, the developers could work with utility engineers to identify the least-cost way to safely interconnect the project. Without this collaboration, TASC argued, the utility may prefer an overly conservative, and ultimately more costly, remediation.

In its November 2015 comments, Minnesota Power pushed back against this recommendation. Though MP acknowledged the interconnection process can seem onerous and costly to customers and developers, it argued that,

> [m]anaging the interconnection of a new DER generator is not a small task, regardless of size. There is currently no such thing as a "plug and play" renewable customer. Adding any generation to the system needs to be analyzed by the utility to ensure that it does not create unintended consequences for other customers. In addition to this, DER customers require new support systems and standards which take time, resources, and training for the utility personnel that work with them.[52]

IREC suggested it may be helpful to review best practices, such as those adopted by states with high penetrations of DERs or the Federal Energy Regulatory Commission (FERC). For example, the pre-application report process—which provides system data and a specific requested interconnection point for a small fee—adopted by California and by FERC Small Generator Interconnection Process.

Fresh Energy requested a review of the Commission's Interconnection Order, calling for the Commission to "[r]evise statewide interconnection standards with enforceable timelines, cost transparency for applicants, and streamlined processes for small DER systems."[53]

Possible next steps

While many parties discussed interconnection issues generally, and some called for a review of the Interconnection Order, there was very little discussion of the either the substance or scope of a

[51] The Alliance for Solar Choice, September 15, 2015 comments, at page 2 (link).

[52] Minnesota Power, November 18, 2015 comments, at page 4 (link).

[53] Fresh Energy, November 18, 2015 comments, at page 2 (link).

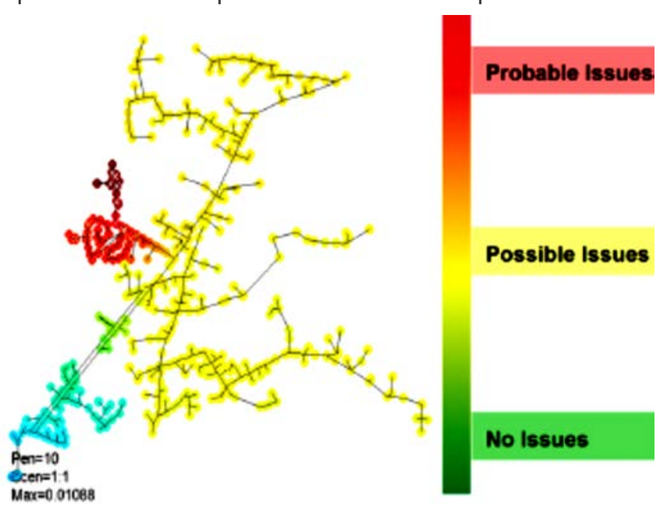
potential review. Here, Staff identifies a few areas that may warrant further review; this list is meant to be illustrative, not exhaustive.

In the 11 years since the Order, there have been technological advances, evolving standards, and considerable work on best practices for DG interconnection nationally. As Dakota Electric mentioned in the third stakeholder meeting, some newer technologies, like smart inverters, weren't considered in the Interconnection Order proceedings. In addition—as was discussed in a Department-led 2012 stakeholder meeting[54] on DG interconnection—many national codes and standards have evolved or been developed since the Order was issued, including IEEE 1547, UL 1741, NEC 694, and UL 6142. Finally, there has been additional work on best practices for DG interconnection, including reports by IREC and EPRI, as well as the FERC Small Generator Interconnection Process.

If the Commission is interested in reviewing the Interconnection Order, Staff encourages it to spend time at the outset to establish the scope of the review. The Interconnection Order is thorough and detailed, totaling 110 pages. It was the result of an extensive stakeholder process, and, all things considered, it has held up well over the ensuing decade. While the Order will inevitably require some updating, Staff believes the review should be targeted. Staff encourages the Commission to be deliberate in setting the scope for the review; additional work at the outset to narrow the focus may produce a more efficient, productive proceeding.

4.4 Hosting Capacity Analyses

A number of parties called on the Commission to require utilities to perform a *hosting capacity* analysis, which would indicate the amount of DG that can be safely interconnected at any given place on the utility's distribution system. As SolarCity explained in a recent whitepaper, "A hosting capacity analysis evaluates a variety of circuit operational criteria – including voltage, loading, protection, power quality and control – under the presence of a specific level of DER penetration – and identifies the limiting factor for DER interconnections."[55]



A hosting capacity analysis can help streamline the interconnection process, as proposed projects with a nameplate capacity below the available capacity can be processed more quickly; and, once the hosting capacity of a circuit is reached, a hosting capacity analysis can help identify potential remediation action(s) that would allow the project to be interconnected safely. While hosting capacity analyses are performed by the utility, some states have required utilities to provide "heat maps" of their distribution territory, like the one to the right[56] so that developers can use them to in their site selection process.

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[54] Meeting notes for the May 31, 2012 meeting can be found on the Department of Commerce's website (link).

[55] SolarCity, "Integrated Distribution Planning: A holistic approach to meeting grid needs and expanding customer choice by unlocking the benefits of distributed energy resources," August 2015 (link).

Stakeholder comments

Several parties urged the Commission to require hosting capacity analyses. In IREC's vision, the Commission would pursue:

> …dynamic hosting capacity analyses that can be shared with customers via regularly updated online maps and other tools. Hosting capacity and other analyses should also help to transform distribution planning process from one focused solely on serving load to one that proactively accommodates the integration of all types of DERs.[57]

Fresh Energy expressed similar sentiments, also noting that the analyses can also help to identify locations in which DER would be most valuable. TASC went one step further, requesting utilities provide not only heat maps, but also the data used to calculate the hosting capacities, so that developers' engineers could work with utility engineers to identify the least-cost method of remediation in the event of a constraint. In the October stakeholder meeting, the Minnesota Chamber of Commerce expressed a similar sentiment, noting that he, as an engineer, is still not allowed to access information that would allow him to optimize DER location.

Some utilities, on the other hand, urged caution. Xcel noted it is working with EPRI on hosting capacity analysis, though it was not sure exactly how the analysis would be used. However, Xcel raised two concerns about releasing the underlying data: first, Critical Energy Infrastructure Information must be protected to ensure the physical security of the grid; second, customer privacy would be compromised if a utility released enough data to identify specific customer usage.

To an extent, this debate over the availability of data is inevitable. In an increasingly digitalized world, data has increasing value. Developers will always want more data and utilities will always be protective of it. All recognize the value of transparency on one hand and privacy and security on the other, but there will always be debate over the appropriate balance between the two. This issue will likely only grow in importance going forward.

Possible next steps

If the Commission is interested in pursuing hosting capacity analyses, it is important to proceed deliberately, with an understanding of the way in which the analyses will be performed and used. For example, when the California PUC required IOUs to perform hosting capacity analyses and make their heat maps publically available,[58] they were a part of a larger, longer distribution resource planning process, as summarized in the box below.[59] Section 4.1 of this report discusses distribution planning more broadly; hosting capacity analyses could be performed as a component of a larger plan, as is the case in California, or independently.

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[56] This hypothetical map is taken from: Electric Power Research Institute, "The Integrated Grid: A Benefit-Cost Framework," February 2015, at Figure 5-4 (link). For a real-world example, see e.g. Southern California Edison's heat maps, which are publically available online (link).

[57] Interstate Renewable Energy Council, September 15, 2015 comments, at page 3 (link).

[58] See e.g. Southern California Edison's heat map website (link).

[59] The box is Staff's summary of Slide 5 from Laura Manz's presentation at the October 30, 2015 stakeholder meeting (link).

California's Distribution Resource Plans will:

- Identify **optimal locations** for the deployment of Distributed Energy Resources (DERs)
- Evaluate **locational benefits and costs** of DERs
- Propose or identify **standard tariffs for deployment** of DERs
- **Coordinate existing commission-approved programs, incentives, and tariffs** to maximize the locational benefits of DERs
- Identify **additional utility spending** necessary to integrate DERs into distribution planning
- Identify **barriers to the deployment of DERs**

If hosting capacity analyses are pursued independently of a larger distribution planning effort, it is still important to consider how to maximize the value of the analyses. As the Illinois Citizens Utility Board put it, the key to a least-cost future is least-cost DER. Hosting capacity in itself provides valuable information to a utility, but its value is maximized only when it's used to identify the location value of DERs and to encourage optimal placement of DERs.

Finally, the Commission will need to identify the data that is necessary for the development of DER without compromising the safety and security of the distribution grid. The availability of grid data is a separate discussion than about Customer Energy Usage Data (see Section 4.7 below); grid data can help a developer identify locations across the distribution grid where the DER may be of most use to the utility or grid operator. Allowing the developer to location DER in areas most beneficial may reduce delays in the interconnection process.

B. Supporting Grid Modernization Technologies

In this section, Staff identifies two technologies that received substantial discussion during the proceeding. These technologies support and enable additional components of grid modernization, but are not necessary ripe for immediate consideration. In other words, at this stage in the proceeding, discussions of these technologies can continue at their current pace without significant Commission or staff direction. It is important to note that in addition to the two technologies discussed below, stakeholders identified many other grid supporting technologies such as Advanced Distribution Management Systems, System Control and Data Acquisition, field and home area networks, and energy storage.

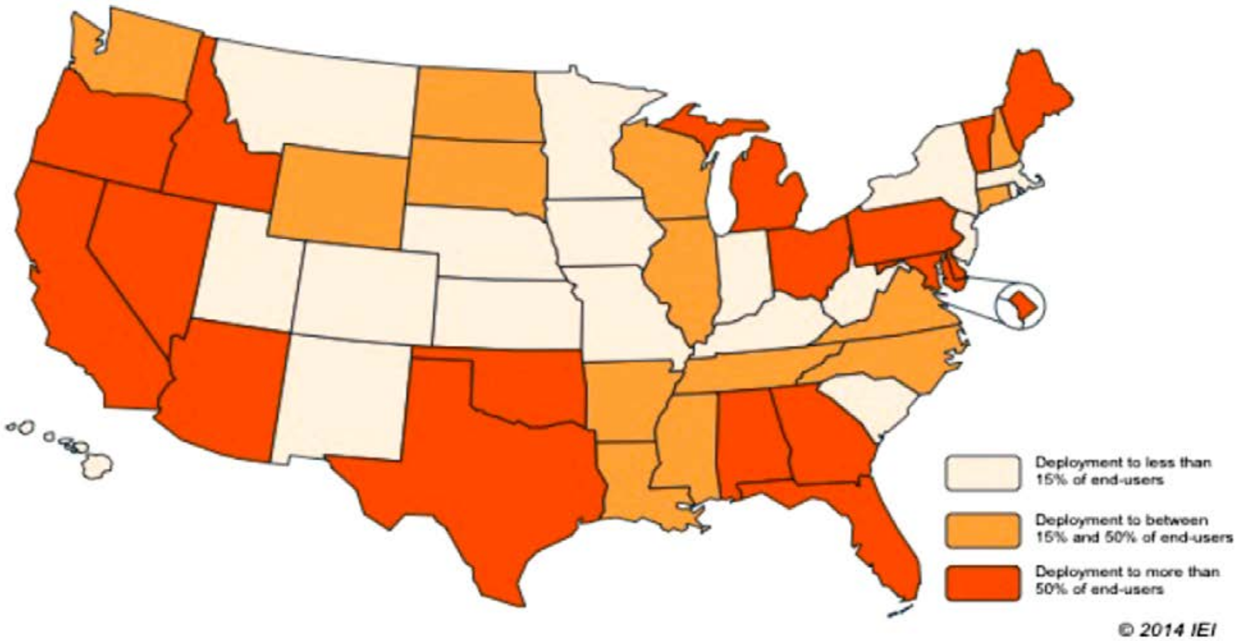
4.5 Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI), also known as "smart meters," are capable of two-way communication, and they are typically able to record consumption data in near real-time, reported in increments of an hour or less. Utility investments in AMI have been driven primarily by American Recovery and Reinvestment Act grants and/or state legislative or regulatory action.[60] As of July 2014, over 50 million AMI meters had been installed nationally, reaching nearly half of the homes in the U.S.[61] The distribution of AMI meters by state can be seen in the map below.[62]

[60] U.S. Department of Energy, "2014 Smart Grid System Report: Report to Congress," August 2014, at page 4 (link).

[61] Institute for Electric Innovation, "Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid," *The Edison Foundation*, September 2014 (link).

[62] Ibid, at page 2.



The operational benefits to utilities[63] from AMI fall into three primary categories. The largest utility benefits typically come via operational savings: remote meter reading and remote connection/disconnection can dramatically reduce the number of times utility personnel have to go to customer premises, and the ability to remotely detect customer connections can dramatically improve fault location, which reduces truck rolls and overall restoration costs. Second, AMI meters can improve billing and customer support: more accurate and timely billing improves utilities' cash flows, more accurate metering data can improve call center customer support, and more granular usage data can enhance the detection of energy theft or diversion. And, third, AMI meters can improve grid management: cumulative metering data can be used by system operators to more effectively manage distribution assets, to integrate distributed resources such as DG and EVs, and optimize voltage and reactive power[64]; at the second stakeholder meeting, Con Ed explained that Volt/VAR Optimization (VVO) and Conservation Voltage Reduction (CVR) were big drivers in the business case for the AMI.

But while operational benefits can be substantial, in some instances they may not cover the large up-front infrastructure investment costs. AMI installations require significant up-front costs, not just for the meters themselves, but also the IT and billing system upgrades necessary to realize their full benefits. For example, a Meter Data Management System (MDMS) allows utilities to better analyze and use AMI data to support a wide variety of utility functions. An MDMS also supports IT-based data protocols that are required for sharing of customer usage information across networks. MDMS networks are vital to greater utilization of data generated by AMI, but its costs to install can be substantial. Moreover, for most utilities, the largest single operational cost-saver of AMI is meter-

[63] In addition to operational benefits, AMI meters have many non-operational benefits that are often harder to quantify. AMI improves the capability for and effectiveness of time-varying rate designs. AMI meters also provide customers with greater control over their energy use; this is especially true for residential customers with programmable thermostats or appliances, or for business or commercial customers with facility energy management systems. However, like reduced frequency and duration of outages, the bulk of these benefits flow to customers, not utilities.

[64] Section 4.6 of this Report discusses Volt/VAR Optimization.

reading automation; for utilities like Xcel that already have automated meter reading (AMR) capability, the marginal meter reading improvement from AMI would be limited. Furthermore, an AMI investment includes not only the meter but also a communication network to enable the services and information from the meter, but across the network as well.

AMI in Minnesota

At present, AMI penetration in Minnesota is relatively low. Covering roughly one fifth of its customers, MP is the only one of the state's IOUs with a significant AMI penetration.[65] While virtually all of Xcel's meters have AMR functionality, as of 2014 it had no AMI installations in the state. As of 2014, OTP had no AMI installed in the state and almost no AMR.[66]

The Commission examined the issue of smart meters in Docket 06-159.[67]

Stakeholder comments

While penetration is currently low, the stakeholder meetings revealed considerable interest in AMI, both among utilities and advocates. MP anticipated a full deployment of AMI, possibly within five to seven years. Great River Energy envisioned a future where all cooperatives employ AMI, though without specifying a date. In fact, the presentations from the first stakeholder meeting suggested most utilities have evaluated AMI (or are currently doing so).

There was also extensive support for AMI among advocacy groups. Several parties—including AEE, ChargePoint, Fresh Energy, Illinois Citizens Utility Board, and TASC—pointed to the potential benefit the additional data would have for customers' decisions regarding their energy use. EPRI cited the tremendous value the additional data and visibility has in distribution planning and management. Others—including Dominion Voltage, Fresh Energy, OTP and Xcel—echoed this sentiment. MP pointed to national examples from Philadelphia and Washington D.C. integration of AMI data into Outage Management Systems reduced outage duration and reduced restoration costs.[68] Others—like AEE, Fresh Energy, IREC, Open Access Technology International (OATI), and Xcel—cited AMI's unlocking the ability to send more accurate price signals through time-varying rates.

Some parties, however, urged caution in the adoption of AMI. Dakota Electric noted that AMI is a major investment, perhaps the biggest single investment decision a coop will ever make; this amplifies the risk of obsolescence. MP echoed this concern, arguing the risks of AMI adoption are greater for smaller utilities, where investments are spread over a smaller pool of customers. Connexus Energy voiced concerns about the lack of interoperability between AMI and other technologies. Others emphasized the possible stranded costs if a utility moved to AMI before existing meters were fully depreciated.

Possible next steps

If the Commission is interested in pursuing AMI further, more record development is necessary. Specifically, there are at least two steps that the Commission may want to take: specification of the

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[65] Several non-rate regulated utilities have also installed smart meters.

[66] All metering statistics come from the IOUs' 2014 "Smart Grid Reports" in Docket 08-948 (link).

[67] See., e.g. the Commission's August 10, 2007 Order in Docket 06-159 (link),

[68] See pages 2-3 of Minnesota Power's September 15, 2015 comments (link).

desired AMI functionality and the development of a business-case analysis, including a cost-benefit analysis.

A useful first step in the consideration of AMI is the identification of expected AMI functionality. For example, in its grid modernization proceeding, Massachusetts developed the list in the box to the right.[69] The California PUC also laid out a list of required functionality in its investigation into AMI.[70]

According to the DPU, AMI should enable

- The collection of customers' interval data, in near real-time;
- Automated outage/restoration notification;
- Two-way communication between customers and the utility;
- Communication with "smart" appliances (with customer consent);
- Conservation voltage reduction programs;
- Remote connection and disconnection; and
- Measurement of customers' power quality and voltage.

In the same Order, the Massachusetts DPU also developed a regulatory framework for the implementation of AMI—a "comprehensive advanced metering plan"—including, among other things, a business case with a benefit-cost analysis. In the Order, the DPU provided guidance on the costs and benefits to be included in the benefit-cost analysis, providing considerable detail.[71]

At this point, Staff does not believe there is an adequate record to either identify expected AMI functionality or to develop a framework for a cost-benefit analysis. However, if the Commission were to initiate an investigation of AMI, these two tasks may be an appropriate starting place.

4.6 Volt/VAR Optimization

A primary function of the distribution system is to transform voltage from high-voltage transmission lines to the appropriate level for customer use. Many types of electronic equipment – such as computers, phones, and televisions – are designed to function within a relatively wide voltage range, but voltage levels above or below this range can lead to inefficient operation and reduced equipment life. Along distribution lines, voltages decline as customers draw power. This means voltages will be higher near substations than they will be toward the end of the line. In order to ensure that the voltage at the end of the line will still be within the acceptable range, conventional practice is to set the voltage toward the upper end of the range when it leaves the substation. The problem with this practice is that more power, at higher voltage levels, is necessary to ensure basic service.

Voltage and volt-ampere reactive optimization (also referred to as VVO or Volt/VAR) is an advanced control application that provides fine-tuning capability for voltage at specific points on distribution feeders. VVO technologies use real-time data and system modeling to provide more precision in voltage regulation (to reduce reactive power losses) and more efficiency in power flow (to increase

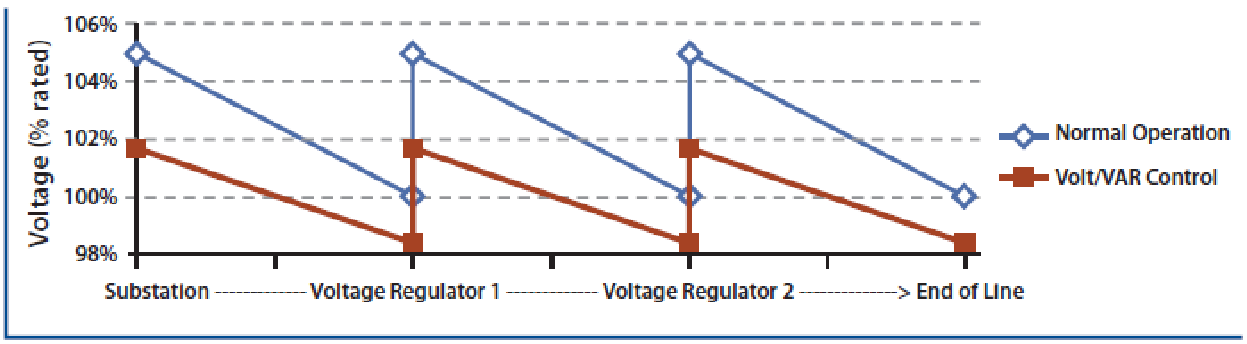
[69] The box is Staff's summary of the list on page 11 of Massachusetts Department of Public Utilities' December 23, 2013 Order in Docket 12-76 (link).

[70] California Public Utilities Commission, "Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing," Rulemaking 02-06-001 (Filed June 6, 2002), at pages 3-4 (link).

[71] Massachusetts Department of Public Utilities, December 23, 2013 Order in Docket 12-76, at pages 20-25 (link).

conservation). Reactive compensation devices (capacitor banks) are used to reduce the reactive power flows throughout the distribution network and are designed to reduce or eliminate the unproductive component of the current, reducing current magnitude – and thus energy losses; this process is illustrated in the Figure 4.1 below.[72] These voltage regulating devices can be run either periodically or in response to operator demand. When properly deployed, VVO can decrease energy consumption significantly without any change in customer behavior. VVO can also be used to reduce peak loads: this practice, known as conservation voltage reduction (CVR), entails decreasing voltage to the lower end of the acceptable range during periods of high demand.

Figure 4.1, Voltage Profiles with and without VVO



Increased efficiencies at the distribution system level can have a significant effect on total system needs. The U.S. Energy Information Administration estimates that Minnesota electricity transmission and distribution losses are on average an estimated 7.4% annually, which is higher than the national average of 6.3%.[73] Utility-specific losses are dependent on various factors including their individual transmission and distribution system depending on line length, operating voltages, time on-peak and operating conditions on and off peak. Minnesota's average system losses average over four billion kWh annually[74]

As part of the 2009 Department of Energy Smart Grid pilot projects, various VVO and CVR pilot projects were implemented. The pilots found that VVO and CVR deployment can achieve a 2-4% reduction in line loss and energy use. [75]

The adoption of other 'smart' distribution technologies is laying the foundation for the distribution operator to better manage and respond to changes occurring on the grid in real-time. VVO, CVR and other distribution grid technologies, like Advanced Demand Management Systems or Distributed Energy Resources Management Systems can assist the distribution grid operator to manage the grid utilizing two-way communications with the field and distribution system control center. As part of a larger modernization effort, VVO can further enhance system efficiencies.

[72] Taken from: Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," Figure 6.1, at page 132 (link).

[73] U.S. Energy Information Agency, "State Electricity Profiles, Table 10: Supply and disposition of electricity, 1990-2013," Released July 8, 2015 (link).

[74] Ibid.

[75] Electric Power Research institute and U.S. Department of Energy, "The Smart Grid Experience: Applying Results, Reaching Beyond – Summary of Conference Proceedings," November 2014 (link).

Stakeholder comments

VVO and CVR came up throughout the stakeholder engagement process. Dominion Voltage discussed the topic extensively in both its first[76] and second[77] comments. At the second stakeholder meeting, EPRI noted the value of CVR as a dispatchable resource, and Con Ed cited the ability to enable VVO and CVR as main drivers in the utility's business case AMI. MP, Rochester Public Utilities, and Xcel are each examining VVO currently. Several other parties—such as AEE, Enernex, Fresh Energy, and IREC—mentioned VVO in stakeholder meetings or written comments.

Possible next steps

If the Commission would like to consider VVO further, Staff believes VVO technology should be evaluated by each utility and within the constraints and plans for each system. As VVO technology is evaluated for deployment, a business-case analysis of the use of VVO technology as an additional distribution system resource should be considered. The Commission could consider VVO on its own, or as part of a broader distribution system plan (Section 4.1).

C. Other policy considerations

This section identifies several policy-related action items that stakeholders raised as important to grid modernization. These items are either already the subject of on-going Commission proceedings or are related to prior Commission actions, so no action in this proceeding is necessary. However, Staff includes these items in this Report to highlight the importance stakeholders placed on these topics as it relates to grid modernization.

4.7 Customer Energy Usage Data (CEUD)

Data will be a major component of grid modernization efforts going forward. Data generated from meters, be they AMI or analog, or 15 minute or monthly, provide information about customer usage profiles. That data can be used to provide customers with detailed and personalized products and services that encourage greater efficiency and demand response. However, in order to enable these types of markets, products, and services, these data need to be made available.

In comments and during the workshop, many parties suggested the use of Green Button Connect be used as a method by which customer usage information is made available in a standardized format for use by the customer and/or a customer-authorized third party.[78] Green Button Connect utilizes an open standard developed by industry at the North American Energy Standards Board called Energy Services Provider Interface. This is an IP-based standard that allows customer usage information to be transmitted between a data custodian (i.e., the utility) to a customer-authorized third party. As noted in the workshops, Green Button Connect has been adopted by several utilities across the country, including Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, and Commonwealth Edison.

[76] Dominion Voltage, Inc, September 15, 2015 comments (link).

[77] Dominion Voltage, Inc, November 18, 2015 comments (link).

[78] There are two versions of Green Button: Green Button Download My Data and Green Button Connect My Data. Here, Staff focuses on Green Button Connect My Data.

Stakeholder comments

Several parties emphasized the importance of CEUD. The Mission:data Coalition devoted the bulk of its written comments to data access issues.[79] AEE and TASC both called for access to Green Button Connect. TASC recommended it as a near-term step, arguing "Bulk downloadable data is critical to spur market innovation. Simply making data viewable but not downloadable is not sufficient, as third parties require the ability to perform analyses on the underlying data to develop insights. The Green Button initiative should inform this process."[80] Other parties—like MP and the Attorney General—recognized the value of customer data, but also stressed the importance of protecting customers' privacy.

Possible next steps

Availability of customer usage information in a standardized format supports market development for customer-sited services and products, including enhanced energy efficiency opportunities for customers. A key component of enabling this type of an option, however, is ensuring that customer privacy is protected. In its on-going data privacy proceeding (Docket 12-1344), the Commission is currently considering appropriate privacy protections for customers, as well as introducing a standardized process by which customers can consent to share information.

In light of the Commission's open data privacy proceeding, additional action may not be necessary at this time within the Grid Modernization proceeding. Nevertheless, Staff believes customer usage information is a key component of enabling greater benefits from grid modernization, and the Commission may want to revisit this discussion at the end of the privacy proceeding.

4.8 Third-Party Aggregation

In response to FERC Order 719,[81] the Commission initiated a proceeding to consider whether or not to allow third party aggregation of retail demand to be bid into wholesale markets.[82] Subsequently, FERC issued Order 745[83] which detailed the methodology by which Aggregators of Retail Customers (ARCs) would be compensated at in wholesale markets.[84]

Starting in 2010, the Commission issued a series of orders prohibiting ARCs from operating in Minnesota. In an August 31, 2011 Order, the Commission required additional reporting from the regulated utilities, including a summary of demand response resources within each regulated utility, future utility actions on demand response, including greater involvement in MISO markets, and regulated utility actions with ARCs. The Commission's April 16, 2013 Order, accepted the utility reports, reaffirmed the prior Commission order allowing ARCs to work in conjunction with the

[79] The Mission:Data Coalition, September 15, 2015 comments (link).

[80] The Alliance for Solar Choice, November 18, 2015 comments, at page 3 (link).

[81] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, Final Rule, FERC Stats. & Regs. ¶ 31,281, 73 FR 61,400, issued October 17, 2008 (link).

[82] Docket No. E-999/CI-09-1449.

[83] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, Final Rule, FERC Stats. & Regs. ¶ 31,322, issued Mar.15, 2011 (link), 76 Fed. Reg. 16,658 (Mar. 24, 2011) (codified throughout 18 C.F.R. pt. 35); Order No. 745-A, Order on Rehearing and Clarification, 137 FERC ¶ 61,215, issued Dec. 15, 2011 (link).

[84] Earlier this year, the United States Supreme Court upheld FERC Order 745 and its compensation methodology; *FERC v. EPSA*, U.S. Supreme Court (Jan. 25, 2016) (reversing D.C. Circuit opinion and upholding Order 745) (link).

regulated utilities, and declined further action to initiate new demand response programs for the regulated utilities.[85] Nevertheless, the Commission noted its on-going interest in demand response and willingness to consider new opportunities for demand response.[86]

Stakeholder comments

In workshops and comments in the instant proceeding, several parties identified this prohibition as a barrier to greater penetration of demand response. Cooperative Energy Futures, OATI, and TASC all advocated for aggregation. The Regulatory Assistance Project recommended the Commission consider permitting third party aggregators, and Fresh Energy and IREC both specifically called on the Commission to revisit its orders in Docket 09-1449.

Those parties believe there will be an increasing need for more flexible resources, both at the distribution and transmission level. They argued that there may be greater opportunities for benefits from the demand side if ARCs were allowed to operate in the state. Staff notes that any party can raise the issue in a resource plan, certificate of need, or in the 09-1449 docket, and make its case in that proceeding.

Possible next steps

If the Commission decides to chart a course towards greater use of DER and better integration of DER with utility operations, the Commission may want to explore whether the prohibition on ARCs may inhibit development of this market.

If the Commission would like to consider ARCs further, one option would be to revisit the discussion in Docket 09-1449. Staff notes the Commission need not completely overturn its previous orders. For example, the Commission could narrowly tailor an exemption to its prohibition by considering the role ARCs could play in utilities' distribution planning and integrated resource planning for retail purposes. In other words, rather than allowing ARCs to aggregate retail demand and participate in wholesale markets, the Commission could simply allow ARCs to operate in retail procurement markets, which are operated by the regulated utilities and remain under the sole jurisdiction of the Commission. Rather than considering how ARCs could partner with IOUs, which is allowed under existing Commission policy, ARCs would be allowed to engage directly with retail customers and participate directly in utility IRP or RFPs as a resource. While analysis would be needed to determine the viability of a retail market for demand response and other aggregated distribution services, it could be focused on in-state procurement needs. For example, electric vehicles utilizing third party charging equipment could allow that third party to aggregate and dispatch those EVs in response to utility needs.

4.9 Time-varying Rates

Though the underlying cost of producing electricity varies considerably both hourly and yearly, nearly all customers in Minnesota pay a single, flat rate for the kWh they consume. Minnesota is not alone in this; the vast majority of electric customers are on flat-rate tariffs. This is largely an

[85] Minnesota Public Utilities Commission, *Order Accepting Compliance Filings*, issued April 16, 2013 in Docket No. 09-1449 (link).

[86] Ibid at page 9.

artifact of technology: meters of yesteryear were only capable of measuring cumulative consumption. Out of necessity, utilities were limited to averaging cost of service into a flat rate.

Because customers pay the same rate regardless of the underlying price of producing the electricity, they have no financial incentive to shift their consumption from more- to less-expensive periods. In order to send customers more accurate price signals—and ultimately reduce system costs—many utilities have moved to time-varying pricing. There are many different types of time-varying pricing, such as Time of Use, Critical Peak Pricing, Peak Time Rebates, and Real Time Pricing.

Under a Time of Use (TOU) design, customers pay a higher rate during certain "on-peak" hours of the day and a lower rate during "off-peak" hours. The hours designated as "on-peak" are those in which market electricity prices or demand are typically the highest. Some TOU designs also include "shoulder" periods with a rate in between the on- and off-peak hours. Table 4.2 provides an example of a two- or three-part TOU rate design.

Table 4.2, Hypothetical TOU Rate Designs

Two-Part TOU Rate			Three-Part TOU Rate		
Period	Hours	Rate	Period	Hours	Rate
On-Peak	2pm – 6pm	$0.16	On-Peak	3pm – 5pm	$0.16
Off-Peak	All others	$0.08	Shoulder	1pm-3pm, 5pm-7pm	$0.10
			Off-Peak	All others	$0.06

While TOU rates account for the variation in costs *within* a day, they do not account for the variation in prices *between* days. For example, though the cost of electricity at 4pm on a 100°F day will likely be much higher than at 4pm on a 70° day, customers would still be paying the same rate under a TOU design. Additionally, TOU does not generally vary by location inside a service territory.

Critical Peak Pricing (CPP) and its cousin, Peak Time Rebates (PTR), attempt to capture these underlying day-to-day cost variations. With CPP, customers pay much higher prices for a period of time during "critical peak pricing hours," which are typically the hours were the costs are highest and the grid is constrained. The CPP rate is typically limited in the number of days per year (and hours per day) in which it can be deployed. For example, the utility may call the CPP rate up to ten days a year for three hours each day. PTR uses the same concept in reverse: rather than being charged a higher rate during "critical" periods, customers are given a large credit if they reduce consumption during those periods. The rate in non-critical periods is increased so that the utility is still able to recover its revenue requirement. Table 4.3 gives a comparison of possible CPP and PTR rate designs.

Table 4.3, Hypothetical CPP and PTR Designs

CPP		PTR	
Period	Rate	Period	Rate
Critical Peak Hours	$0.60	All hours	$0.10
All other hours	$0.08	Critical Peak Discount	$0.60

Real Time Pricing (RTP) is even more dynamic, with rates varying hour by hour to reflect wholesale market prices. This option sends customers the most accurate price signals, but does so at the possible risk of customer confusion. The lack of predictability may also make it more difficult for customers to shift usage. Proliferation of "smart" technologies—like smart appliances—and/or energy management applications may allay some of these concerns.

Party comments

Through written comments and stakeholder meetings, several parties urged the Commission to expand the use of time-varying rates. In its September comments, AEE cited time-varying rates as one of the "six key features" Minnesota's distribution system should have.[87] Fresh Energy, IREC, and OATI also explicitly endorsed expanding time-varying rates. Xcel also seemed amenable to the concept, positing the policy objective of sending "more accurate price signals to incent efficient customer behaviors and align rates with cost drivers on the system."[88]

Possible next steps

The Commission is currently in the process of investigating[89] alternative rate designs for Xcel Energy's residential customers. The Commission recently issued a Notice for Comment in the docket, which states "The Commission expects to hold at least two workshops in the coming months on topics raised in this notice. Upon conclusion of the workshops, the Commission may seek additional comments on topics raised by initial comments and in the workshops."[90] The investigation isn't limited to time-varying rates, but TOU and CPP were two of the five proposed options to be considered.

In light of this ongoing investigation, additional action on time-varying rates may not be necessary at this time. The written comments and stakeholder meetings are sure to provide a robust record on the alternatives laid out in the Notice. While the existing docket is somewhat narrow—thus far, it has only considered rate design for one class (residential) of one utility (Xcel)—it is likely that much of the discussion will be relevant to other utilities and customer classes. The Commission could let the existing process run its course and then later decide whether to expand. Alternatively, if the Commission is interested in pursuing time-varying rates for all IOUs, it may be more efficient in the long run to expand the scope of Docket 15-662 before the record is developed further.

Section 5 | Phase 3: Long-term Vision for Grid Modernization

In Phase 3, the Commission would consider larger changes to the utility business model and market structures in Minnesota. While this phase could technically occur concurrently with Phase 2, Staff believes it would be more prudent to delay these discussions until after Phase 2 is completed, given the scope and importance of the questions considered in this phase, limited staff resources, and the lack of urgency. However, it may be worthwhile for the Commission to consider these issues at this time, as this larger and longer-term perspective may provide valuable context for decisions in the other phases.

Below, Staff outlines several topics raised by parties during stakeholder meetings and in comments; the Commission can act on these at any time, but it may be wise to delay specific actions on these

[87] At page 2 (link).

[88] Xcel Energy, September 15, 2015 comments, at page 1 (link).

[89] Docket 15-662 (link).

[90] Docket 15-662, Notice Seeking Comment on Procedural Schedule, Issued February 16, 2016 (link).

items at this time and continue to monitor the debates occurring across the industry and in other states, such as California and New York.

5.1 Business Model

As customers adopt distributed resources, they become less reliant on the incumbent utility for the provision of electricity and may consume less of it over time. Fewer sales mean less revenue collected, which means the utility needs to make up that lost revenue from the remaining customers. The question becomes how to keep the utility solvent.

This section outlines a few options for future business models for the Commission to consider. While similar discussions are currently happening across the country—most notably in Hawaii, California, and New York—the circumstances in those states are materially different than those in Minnesota. Indeed, Minnesota, with vertically integrated utilities and relatively low penetrations of distributed generation, does not have the pressing needs of those other states. While distributed generation is increasing in the state and will take on more importance in the future, we have the luxury of time to consider and address these issues in a more measured and reasoned manner.

Utility v. third party

Several parties, such as SolarCity, have advocated for a much larger role for market participants in the provision of direct-to-consumer products and services. Additionally, these parties have argued for a more open procurement process so that third party resources can compete on an equal footing with utility-owned resources in utility procurement processes and integrated resource planning (IRP). In this construct, the utility would act as the wires company and/or the distribution system operator (DSO), running a distribution market similar to the role of an Independent System Operator in wholesale markets. The utility would remain responsible for reliability needs of the grid and would operate a distribution market for electricity services.

A second option would be for the utility to maintain its position with customers through its on-going relationship of providing electricity and other products. Utilities have positioned themselves to be the "store front" for products to offer to consumers, either directly from the utility or through third party partners. In this construct, a utility would be much more involved in the direct interaction with the customer, and may be able to leverage its market power to provide products at lower costs, both system-wide and to individual customers.

Both of these are reasonable futures. There will be increasing pressure to act upon one or a blend of these outcomes at some point in the future. However, it is possible that actions taken in Phase 2 may put Minnesota on the path to one or the other.

Identification of grid services

Regardless of the market option above, the direction of the industry appears to be trending towards the advent of a services-based model. In this vision, the utility or DSO begins to identify new needs in the operation of the distribution grid, similar to the development of the transmission grid. Instead of just providing electricity, the utility or DSO would begin to procure ancillary services, such as VVO or location-specific demand response.

This vision is highly dependent on the penetration of DER, adoption of technologies on the customer side, and a more advanced distribution grid capable of real-time visibility down to (at least) the transformer, if not the meter. Thus, it is highly dependent on technology, both on the utility and customer sides of the meter. This vision is also dependent on the existence of markets for the resources that flow from customers, advanced technologies, and grid operations. For example, a utility or DSO could have a localized need for excess generation to be consumed. An electric vehicle or storage resource could bid in its availability to consume or store that excess electricity and be paid for that service, at that location. This distributed locational marginal price could enable a wide variety of market options and methods to enhance the reliability and resilience of the grid. By allowing the utility, acting as a DSO, to procure these services, it may be able to mitigate new infrastructure investments by procuring non-utility resources to meet future needs.

This example raises the question of who should bear the risk: is it more reasonable for the utility (and, by extension, its customers) to front the costs for more procurement of demand response, or for the market, with less impact on customers. Should a utility's customer base bear the entire risk of a large investment that is utilized by a limited number of customers, should third parties and the market bear that risk, or some should there be combination of risk sharing?

Discussions of this future are on-going throughout the industry.[91] In these discussions, high DER scenarios are assumed and pressure is placed on the regulator and utility to maintain high reliability levels. Additionally, identifying and understanding how distribution services can provide the utility or DSO more flexibility in responding to immediate needs, where, for example, the utility may have just shed load or shut down generation in prior situations.

5.2 Regulatory Model

While not explicitly raised in comments by parties, the extent to which any of these future options are considered will be based on evolving views of regulators and policy makers, the orientation of the utility, the engagement of electricity customers, and the composition and development of associated markets for technology and services. In a scenario in which market solutions are preferred, the regulator becomes less of an active voice in directing certain solutions, and, instead, acts as a market monitor. The regulator would oversee and ensure open access to markets, customers, and the grid, or network. If, on the other hand, the utility maintains its monopoly role, the regulator maintains much the same authority today—where the regulator and regulated monopoly attempt to mimic market solutions, but with other preferences put in place.

With the increase in easier access to technology by the customer, a balance will need to be struck between the regulator and the regulated utility to identify situations in which the monopoly will best serve the needs of the customer base and create policies appropriate to the situation. The Commission should be mindful of the differences the Commission would or could play in a future electricity world. No decision is necessary at this stage in Minnesota's path towards the future, but, much like utility business model, the role of the regulator will also need to be examined.

[91] Examples of this future include transactive energy, efforts in Hawaii where there are large penetrations of DER throughout the distribution grid, and in leading research projects.

One component, which was not explicitly called out in comments, is the role of research and development needs at the utility. Many of the technologies currently identified, or future ones not yet identified, take years for study and evaluation, which then allow for a cost-effectiveness methodology. With the changes anticipated for the grid over the next decade, and the general pace of utility investment decisions (including rate cases), it may be challenging for the distribution utility to keep abreast of the fast turnaround time of the market. Allowing the utilities the opportunity to trial technologies and prove the benefits may be more useful than relying solely on utilities to show that certain investments are cost-effective from day one. The grid, available technologies, and customer expectations are changing rapidly, but keeping the utilities stuck in an existing regulatory program puts the utility in an untenable situation of being unable to effectively respond to these changes. Allowing the utilities to utilize some amount of funds to trial these new technologies will help the utility and the state to pro-actively test out the abilities, costs, and benefits of these new technologies at the start. Thus, the Commission should recognize that R&D funding will result in some failures. Indeed, failure, in an R&D context, is valuable; having technology fail in the R&D phase not only avoids the potential ratepayer impacts of a larger investment, but also provides an educational opportunity.

5.3 Performance Based Ratemaking

Performance Based Ratemaking (PBR) is an alternative model for utility cost recovery. In the traditional cost-of-service rate recovery models, the utility is incentivized to both sell more goods, i.e., electricity, and build more capital projects, i.e., infrastructure. The utility usually receives a higher rate of return on capital projects than operation and maintenance (O&M), and collects more revenue through more sales. This model does not encourage energy efficiency, either through better use of existing infrastructure or any reduction in consumption. An initial step to remove the incentive to sell more is decoupling, which separates a utility's revenue from sales.[92] To remove the incentive to build more, PBR is option. In this instance, the utility could earn an incentive by meeting certain metrics or goals, which would replace the lost revenue requirement foregone by avoiding capital projects. PBR could be used for a few different purposes. For example, metrics and goals could be developed to encourage the utility to operate its grid more efficiently through O&M rather than new capital projects to offset the "lost" Return on Equity, an incentive could be added to the O&M revenue to make up this difference.

A version of PBR is in effect in Great Britain through its RIIO model.[93] Additionally, the Illinois Legislature codified several PBR-like incentives in 2011; those incentives were designed to encourage the Illinois utilities to invest in certain projects to make the grid more efficient, but in a way to allow the utilities to recover lost revenue.[94]

PBR is also a main interest of the e21 Initiative. In the e21 Phase 1 report, it recommends the state move to a PBR mode of regulation as part of a larger regulatory and utility business model evolution. The Phase 1 Report was submitted to the Commission by Xcel in Docket 14-1055, though the Commission has not taken any formal action in that docket. In e21 Phase 2, PBR

[92] Xcel is partially decoupled, pursuant to the Commission's May 8, 2015 Order in Docket 13-868 (link).

[93] For more information, see the Office of Gas and Electricity Markets' RIIO website (link).

[94] Illinois Public Act 097-0616 (link).

continues to be a major focus, with a White Paper expected to provide e21's vision for PBR in Minnesota.

In Phase 3, understanding the appropriate role for the utility, in regard to its relation to the customer and the market, implicates changes to the way things are done today. PBR is one example the Commission could consider in this longer term discussion.

Appendix A: Summary of Stakeholder Meetings and Comments

In the fall of 2015, the Commission hosted three stakeholder meetings and solicited two rounds of written comments. Below, Staff provides a brief summary of the comments and meetings. All comments and the presentations from the stakeholder meetings can be found on the Commission's website.[95]

Written Comments

Between two rounds of written comments, the Commission received comments from twenty parties,[96] representing a diverse array of perspectives, including utilities, advocacy groups, state agencies, and technology vendors.

For the first round of written comments—received on September 15th, 2015—the Commission requested stakeholder input on the following topics:

- 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 the second round of comments—received on November 18th of 2015—the Commission asked stakeholders to comment on the following topics:

- What objectives and principles should guide grid modernization in Minnesota and an integrated distribution planning process?
- What pathways, both procedural and substantive, are necessary for the Commission to take? Please identify these steps by timing (near, mid or long term) or other relevant parameters.
- What are the benefits and costs that could result from grid modernization? Are there regulatory steps the Commission should take to balance the costs and benefits for the public interest?

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[95] These documents can be found on the Commission's eDockets website for Docket 15-556 (link). From the Commission's homepage (mn.gov/puc/), select "eDockets" and then enter docket number 15-556 and select "search."

[96] Comments were submitted by: Advanced Energy Economy Institute, Bridge Energy Group, ChargePoint, Cooperative Energy Futures, Dakota Electric Association, Dominion Voltage, Energy Storage Association, Enernoc, Fresh Energy, Interstate Renewable Energy Council, Minnesota Center for Environmental Advocacy, Minnesota Power, the Office of the Attorney General, Open Access Technology International, Otter Tail Power Company, Renewable Energy Systems Americas, the Alliance for Solar Choice, the Mission: Data Coalition, Wind on the Wires, and Xcel Energy.

- What specific regulatory barriers exist to meeting your objectives? These can be barriers the utilities are facing, as well as barriers to customers and other participants.

First Stakeholder Meeting

The first stakeholder meeting, which took place on September 25th, focused on Minnesota's electric utility distribution systems, with discussion of design, operations, performance, capability, and planning processes for existing distribution systems.[97] Nearly 150 people attended the all-day event, including utility representatives, energy policy advocates, technology vendors, university professors and students, and legislative and state agency staff.

After welcoming remarks from Commissioner Nancy Lange, presentations were given by Brian Amundson of Xcel Energy and Will Kaul of Great River Energy. Mr. Amundson provided an overview of electric distribution systems and an explanation of the current distribution system planning process, including a discussion of the potential benefits of and challenges posed by emerging distribution system technologies. Mr. Kaul elaborated on these developments, emphasizing the transformative potential of technologies like distributed generation, "smart" devices, advanced metering, electric vehicles, and information communication technologies.

These presentations were followed by a panel[98] on Minnesota utilities' electric distribution systems. The panel included representatives of each of the state's three investor-owned utilities (Minnesota Power, Otter Tail Power, and Xcel Energy) as well as a cooperative utility (Dakota Electric) and a municipal utility (Rochester Public Utilities). The panelists provided basic information on each of their distribution systems, as well as a discussion of their utility's distribution system planning process.

In the afternoon, a second panel[99] provided stakeholders' perspectives on grid modernization in Minnesota. The panel included representatives from Minnesota state agencies (the Department of Commerce and the Office of the Attorney General), energy policy advocates (Fresh Energy and the Institute for Local Self-Reliance), and customer groups (the Minnesota Chamber of Commerce and the Metropolitan Council). The discussion focused on the important policy objectives for grid modernization, emerging customer behaviors and preferences, and the features the electric grid will need to meet these policy objectives and customer demands.

In addition to these presentations, there were several question and answer periods throughout the day.

Second Stakeholder Meeting

The second stakeholder meeting took place on October 30th, 2015.[100] The topic for the meeting was national distribution grid modernization work and emerging best practices. The all-day event

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[97] The agenda for the meeting is available on the Commission's eDockets website (link).

[98] Panelists included: Craig Turner, Dakota Electric Association; Reed Rosandich, Minnesota Power; Rick Johnson, Otter Tail Power; Steve Cook, Rochester Public Utilities; and Brian Amundson, Xcel Energy.

[99] Panelists included: Joseph Dammel, Office of Attorney General; John Farrell, Institute for Local Self-Reliance; Bill Grant, Department of Commerce; Holly Lahd, Fresh Energy; Larry Schedin, Minnesota Chamber of Commerce; and Jason Willets, Metropolitan Council.

[100] The agenda for the meeting is available on the Commission's eDockets website (link).

attracted approximately 100 attendees, including utility representatives, energy policy advocates, technology vendors, university professors and students, and legislative and state agency staff. The agenda was divided into four issue areas, each with a presentation and reaction panel.

The first presentation was given by Jeff Smith, who is the manager of the Power System Studies Group at the Electric Power Research Institute (EPRI). Mr. Smith's presentation, *An Integrated Approach to Distribution Planning*, described EPRI's work to help utilities maximize the benefits and minimize the impacts of Distributed Energy Resources on their system. This was followed by a reaction panel including Curt Volkmann of Fresh Energy, Jenny Edwards of the Center for Energy and Environment, and Jeffrey Schoenecker of Dakota Electric Association.

The second panel focused on the Grid Modernization effort underway in New York. Damian Sciano, the Director of Distributed Resource Integration at Consolidated Edison of New York, gave a presentation on New York's Reforming the Energy Vision initiative, focusing on its implications for distribution system planning. A reaction panel followed, featuring Hannah Polikov of Advanced Energy Economy, Jeremy Laundergan of Enernex, and Lise Trudeau of the Minnesota Department of Commerce.

The third panel addressed California's work on Grid Modernization. A presentation was given by Laura Manz, a Senior Fellow with More Than Smart Initiative. Ms. Manz described California's scenario driven, multi-stakeholder distribution planning process. This presentation was followed by a reaction panel with Brian Amundson of Xcel Energy, Sky Stanfield of the Interstate Renewable Energy Council, and Carlos Gonzalez of the Alliance for Solar Choice.

The day's fourth and final panel discussed regulatory considerations for Grid Modernization. The main presenter was Janine Migden-Ostrander, who is a Principal with the Regulatory Assistance Project. Ms. Migden-Ostrander's presentation, which highlighted policy considerations in distribution system planning reform, was followed by a reaction panel comprised of David O'Brien of Navigant Consulting, David Kolata of the Illinois Citizens Utility Board, and Rolf Nordstrom of the Great Plains Institute.

Each of these reaction panels included a half-hour question and answer period with the audience.

Third Stakeholder Meeting

On November 20th, the Commission held its third stakeholder meeting,[101] which was devoted entirely to stakeholder perspectives, giving interested parties an opportunity to provide feedback on current distribution planning processes and to suggest next steps for the Commission. Roughly 100 people attended, including utility representatives, energy policy advocates, technology vendors, university professors and students, and legislative and state agency staff.

The event featured a single stakeholder panel, with representatives of a wide-variety of stakeholder groups. Panelists included: Carolyn Brouillard of Xcel Energy, Timothy DenHerder-Thomas of Community Power, Carlos Gonzalez of The Alliance for Solar Choice, Bill Grant of the Minnesota Department of Commerce, Daniel Gunderson of Minnesota Power, Ali Ipakchi of Open Access Technology International, Holly Lahd of Fresh Energy, Maria Seidler of Dominion Voltage, Beth

[101] The agenda for the meeting is available on the Commission's eDockets website (link).

Soholt of Wind on the Wires, Sky Stanfield of the Interstate Renewable Energy Council; Lise Trudeau of the Minnesota Department of Commerce, and Craig Turner of Dakota Electric Association.

During the first discussion session, panelists shared their opinions on the following questions:

- What objectives and principles should guide grid modernization in Minnesota and an integrated distribution planning process?
- What are the benefits and costs that could result from grid modernization? Are there regulatory steps the Commission should take to balance the costs and benefits for the public interest?

After a break, the same panel addressed a second set of questions:

- What pathways, both procedural and substantive, are necessary for the Commission to take? Please identify these steps by timing (near, mid or long terms) or other relevant parameters.
- What specific regulatory barriers exist to meeting your objectives? These can be barriers the utilities are facing, as well as barriers to customers and other participants.

As with the first two meetings, the agenda included an extended question and answer period after each panel discussion section.