



e21 Initiative

PHASE II REPORT

On implementing a framework for a
21st century electric system in Minnesota

DECEMBER 2016

About the e21 Initiative

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. The initiative brings together key interests including utilities, consumer advocates, energy technology companies, other businesses, environmental and academic organizations, and government to accomplish this goal and enable Minnesota to continue to lead in shaping an electric system for the 21st century.

The e21 Initiative is convened by the Great Plains Institute and the Center for Energy and Environment with guidance from the following project partners: George Washington University Law School, Xcel Energy, and Minnesota Power.



Staff to the e21 Initiative include co-directors Rolf Nordstrom, President and CEO of the Great Plains Institute, and Mike Bull, Policy Director for the Center for Energy and Environment. Staff to e21 also includes the following people at the Great Plains Institute: Jennifer Christensen, Senior Associate; Dane McFarlane, Senior Research Analyst; and Doug Scott, Vice President of Strategic Initiatives.

The McKnight Foundation, the Joyce Foundation, and the Energy Foundation have been the principal funders of the e21 Initiative, with significant contributions from Xcel Energy and Minnesota Power and essential in-kind contributions from numerous organizations and stakeholders.

About the Phase II Report

The e21 Initiative developed its phase I report on a consensus basis; the ideas and recommendations in the report were intended as a cohesive package to be taken together and supported as a whole by the e21 stakeholders. Consensus did not mean that each participant is equally enthusiastic about every idea, and, importantly, consensus did not require participants to give up their right to object to future implementation details.

Phase II aimed to build on the consensus recommendations of phase I, but in more specific areas, with more participants involved. That was the goal. The phase II report reflects a great deal of work by participants representing a broad cross-section of the public interest, and a substantial increase in the understanding of the positions and concerns of all participants in this phase. On a number of items, however, consensus was hard to come by. In the end, the e21 co-directors decided not to push the group to final consensus on these items or on the report as a whole, deciding that the additional work and time necessary to come to a more complete consensus would outweigh the benefits of achieving it. Instead, in those areas, the phase II report reflects the range of views held by participants or indicates more specific areas of disagreement.

Each white paper was initially developed in e21 subgroups and informed by discussions in the full e21 group. The phase II overview and summary represent a synthesis of e21's phase II efforts by staff to e21. Given that this report is not a consensus-based document, the views expressed in this report should not be attributed to any individual participant of e21.

This report is available online here: www.betterenergy.org/e21-PhaseII

How to Read this Report

The phase II report presents key information and guidance for decision-makers to consider in order to implement e21's phase I consensus recommendations, released in December 2014.

This report was written primarily for Minnesota's electric utility regulators, policymakers, organizations representing ratepayers, and others who have a stake in the direction of Minnesota's future electric system. It is also e21's hope that this report will be useful to others outside of Minnesota who are grappling with similar issues, albeit in their own context.

The phase II report is intended as a cohesive package, with each white paper relating to and supporting the other three.

e21 Initiative Phase II Participants

Note: As described in more detail in the above ‘About the Phase II Report,’ views expressed in this report should not be attributed to any individual participant of e21.

Also note that participants that have changed organizations since the start of e21’s phase II have their new position and organization in parentheses. An asterisk indicates they are no longer at their organization and are no longer participants in e21.

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e21 Initiative Overview & Summary of Phase II White Papers

Introduction

Minnesota's e21 Initiative was launched in 2014 to provide a collaborative forum outside of the formal regulatory process for responding effectively to the changes occurring in the electric industry. Its purpose is to provide regulators and other decision-makers recommendations on how Minnesota's regulatory framework, and the existing utility business model, might evolve to continue to protect and promote the public interest. Rather than define a specific future, this report offers an actionable framework to help guide and shape future consideration of regulatory and policy options.

The electric industry is undergoing profound changes and experiencing challenges from a number of different directions. For example, a growing number of customers (households, businesses, and communities) are expressing the desire for cleaner electricity and convenient energy management and home automation, as evidenced by the growth of products such as smart thermostats. Simultaneously, state and federal policy is also putting pressure on electric utilities to lower greenhouse gas emissions by moving to cleaner electricity generation.

In addition, Minnesota ratepayers have a strong need to control costs, including costs for electricity, for a variety of reasons:

- Commercial and industrial customers compete in an unprecedented globalized marketplace with increasing competition and downward pressure on pricing for goods and services. This may result in a more depressed business climate with fewer businesses developed, and fewer jobs created in Minnesota.
- Low-income residential customers who experience electricity cost increases may face higher instances of shut-offs or may choose to forego other necessary expenses.
- Customers of all rate classes who are able may choose to relocate in states with lower electricity costs, though location decisions are clearly the result of a mix of factors.

The improved cost and performance of large-scale wind and solar has contributed to dramatic increases in the integration of those resources into the electricity mix. A wide range of customer-driven distributed energy resources¹ have also declined in cost and increased in number on the electric system, driven by consumer decisions that are generally outside the ability of utilities or regulators to control. The emergence of distributed energy resources poses some new costs and benefits for the electric system as a whole. For example, on one hand they can contribute to a more resilient, responsive electric system (e.g., functioning through a bad storm), yet are inherently more challenging to plan for and coordinate than a relatively small number of large power plants. Distribution grid planners at utilities will increasingly need to prepare the electric

¹ Distributed energy resources are supply- and demand-side resources that can be used throughout an electric distribution system (i.e., on either the customer side or on the utility side of the customer meter) to meet energy and reliability needs of customers. They include end-use efficiency, distributed generation (solar photovoltaics, combined heat and power, small wind), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (communications and control technologies).

grid to accommodate the inherently unpredictable number and location of everything from new electric vehicles that consumers will plug into the grid to new rooftop solar installations. And managing a more dynamic, highly distributed electric system with many more devices and suppliers of power and services will require additional investment in a wide range of technologies. In the midst of these multi-faceted challenges, utilities are experiencing historically flat (and in some cases declining) load growth even as they face the need to invest in aging electric infrastructure, enhance security, reliability and resiliency, and reduce environmental impacts.

These changes and challenges have caused a number of utilities and states to consider whether and how to change the traditional electric utility business model, which is based on compensation to the utility for the physical infrastructure that it builds and maintains, and how much power it sells. And while these issues have not emerged in Minnesota in ways that make their consideration an emergency, the wide range of stakeholders who have come together for the e21 Initiative believe that developing a shared view of how best to respond to these rapid changes in the electric sector—in advance of any particular crisis—will serve the public interest and can contribute to Minnesota’s long-term prosperity.

The state is well positioned to continue working collaboratively and thoughtfully on these issues and address expected changes in ways that create opportunity and benefits for Minnesota’s large and growing clean energy-related businesses and electricity providers, regulators, and customers.

The fact that Minnesota’s electric system is vertically integrated and fully regulated (like a majority of U.S. states) suggests that the state has an opportunity to lead and share what it learns with others. Unlike utility and regulatory reform efforts elsewhere, the e21 Initiative was not mandated by any official body, but instead arose out of mutual interest among key stakeholders who saw the need for reform, albeit for quite different reasons. They deserve enormous credit for devoting years of effort to shape Minnesota’s electric system rather than simply waiting to see what happens.

Phase I Background

In its initial phase, e21 set forth two overarching goals, a number of guiding principles, and a high-level blueprint for evolving Minnesota’s regulatory framework and the utility business model. The two big goals that emerged from e21’s first year were to:

- *Shift away from a business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it, while maintaining fair and competitive pricing, reliability, and minimal environmental impacts*
- *Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want*

This shift is meant to encourage a least-cost, best-value approach to achieving agreed-upon performance outcomes that includes consideration of both central station and distributed energy resources in meeting electric system needs.²

e21 Guiding Principles

The consensus guiding principles adopted by the e21 Initiative in its first year represent the attributes that e21 participants believe should characterize any future electric system in Minnesota. These principles are meant to guide regulatory and statutory changes. Many of them are in tension with one another, and they should thus be taken as a set. The principles are to

- a. align an economically viable utility model with state and federal public policy goals
- b. provide universal access to electricity services, including affordable services to low-income customers
- c. provide for just, reasonable, and competitive rates
- d. enable delivery of services and options that customers value
- e. recognize and fairly value grid services and “distributed energy resource” services
- f. assure system reliability and enhance resilience and security, while addressing customer privacy concerns
- g. foster investment that optimizes economic and operational efficiency of the system as a whole
- h. reduce regulatory administrative costs where possible (e.g., results in fewer rate cases or otherwise reduce the burden of the regulatory process)
- i. facilitate innovation and implementation of new technologies

² “Least cost, best value” includes the analysis of desired outcomes and then the search for methods that will achieve those outcomes at the lowest cost for customers.

e21 Phase I Recommendations

The *e21 Initiative Phase I Report* delivered a package of 14 recommendations that, taken as a whole, provide a framework for a new regulatory approach that adheres to the principles listed above. The recommendations fall into four main categories of reform: performance-based ratemaking, customer options and rate design, planning, and regulatory processes. The individual recommendations were as follows (see the phase I report for the detailed recommendations list):

- a. Allow a multi-year, performance-based regulatory framework for utilities that wish to opt in
- b. Require utilities that opt into a multi-year, performance-based framework to file a comprehensive business plan (covering up to five years) consistent with a 15-year (or longer) integrated resource analysis (in e21's second phase, the latter is now referred to as an integrated systems plan)
- c. Revise Minnesota statutes to allow utilities that opt into a multi-year, performance-based framework to replace the current integrated resource plan with a 15-year (or longer) integrated resource analysis that guides the utility business plan; and allow utilities to coordinate the filings of the business plan and integrated resource analysis
- d. The [Minnesota Public Utilities] Commission should encourage the use of pilot programs or other methods for testing and evaluating components of a multi-year, performance-based framework
- e. The Commission should establish clear methods for determining the value of grid services and distributed energy resource services, and set rates to
 - o fairly compensate customers
 - o cover utilities' fixed costs of maintaining the system
 - o provide clear price signals to encourage economically efficient choices
 - o send appropriate price signals to achieve the e21 principals and outcomes
- f. The [Minnesota Public Utilities] Commission should review and adjust time-varying rates for energy services so that they send more accurate and effective price signals
- g. Enable innovative product and service options and technologies by revising Minnesota statutes and regulations
- h. The [Minnesota Public Utilities] Commission and Department of Commerce should use their existing authorities to achieve e21 principles and outcomes, and review and recommend revisions to their authorities where needed
- i. The Minnesota legislature should appropriate the resources necessary for the [Minnesota Public Utilities] Commission and the Department [of Commerce] to implement e21's recommendations
- j. The [Minnesota Public Utilities] Commission and the Department [of Commerce] should institutionalize the practice of using a collaborative regulatory process
- k. The [Minnesota Public Utilities] Commission and the Department [of Commerce] should look for opportunities to initiate generic dockets
- l. Initiate forward-looking stakeholder processes to address emerging issues
- m. Develop a transparent, forward-looking, integrated process for modernizing the grid
- n. Identify and develop opportunities to reduce customer costs by improving overall grid efficiency

The task for the e21 participants in phase II was to make more specific guidance in these areas, with the goal of devising implementation strategies.

Phase II Background

e21's second phase built on the initiative's earlier efforts and began to develop the details of implementing the multi-year, performance-based regulatory framework described in phase I. At the outset of phase II the e21 participants adopted the following objectives:

Objective 1: Inform the Minnesota Public Utilities Commission's (PUC's) grid modernization process and increase transparency in distribution planning.

Objective 2: Formulate principles and identify best practices for transitioning a portion of utility revenue from traditional cost-of-service to a value- and performance-based approach.

Objective 3: Identify and prioritize challenges and opportunities, goals, and principles for rate reform.³

Objective 4: Evaluate pros and cons of the current integrated resource planning process and identify potential improvements, including the potential for incorporating more information about both wire and non-wire alternatives to lead to an integrated systems plan.

Objective 5: Establish deeper and broader understanding and ownership of e21's recommendations and outcomes.

To achieve these objectives, e21 participants adopted a two-pronged approach: first, the initiative used its monthly meetings to provide participants a common base of cutting-edge information and insights from local and national experts on the current state of distribution grid planning and technology developments, various performance-based system possibilities, and new approaches to long-term integrated systems planning. These expert presentations informed e21 deliberations on what would be required to implement the recommendations from phase I. Second, e21 participants agreed to draft a series of three white papers, each focused on a specific part of the proposed new regulatory framework. Each white paper was to be developed by a subgroup of e21 participants and other outside experts and then reviewed by the entire e21 participant group. The three papers spell out how Minnesota might approach

- a. performance-based compensation for utilities
- b. integrated systems planning
- c. grid modernization (and distribution-level planning)

Summary: Phase II White Papers

The three white papers build on phase I and should be considered collectively, as all aspects of the modern grid are interrelated: any discussion of compensating utilities based on their performance in achieving particular outcomes necessarily involves an understanding of what grid enhancements would be necessary for the system to support achieving those outcomes. In addition, any such grid enhancements would require the traditional integrated resource planning

³ e21 participants chose to postpone the group's work on electricity rate reform largely due to limited bandwidth of the participants and staffing organizations. The group understands that rates are a crucial part of any discussion of a new utility business model and are central to a great deal of the action on these issues throughout the country. Indeed, the Minnesota PUC has now launched an exploration of alternative rate designs.

process to take those changes into account in planning for the electric grid's long-term needs, grid operation, and revenue requirements for the utilities.

Similarly, consideration of new integrated resource planning processes would be incomplete at best without an understanding of what's driving the need to modernize our grid and how expected changes at the distribution grid level will shape the way we do long-range planning for the electric system. Moreover, evolving the traditional integrated resource planning process toward an integrated systems plan (as proposed by e21) also requires an understanding of how new performance-based utility compensation mechanisms may influence how utilities and third parties meet future electricity needs.

In sum, an understanding of the work by the e21 Initiative in phase II requires that the three white papers be read as a package. To aid in this systems view, the following summaries describe each white paper, its recommendations, and its conclusions, and shows how it relates to the other two.

Performance-based Compensation

A central recommendation of the *e21 Initiative Phase I Report* is the shift to a more performance-based compensation framework, where some portion of the utility earnings is linked to utilities' performance on outcomes valued by customers and supportive of state energy policies. This shift would require updating the manner in which Minnesota regulates utilities in two fundamental ways. As noted above, it would accomplish the following:

1. *Shift away from a business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it, while maintaining fair and competitive pricing, reliability, and minimal environmental impacts*
2. *Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want*

As envisioned in phase I of e21's process, this shift is intended to achieve four core objectives:

- a. Utilities become indifferent to how a particular system need is met (e.g., large central generation or distributed generation) and by whom (utility or non-utility). Utilities would evaluate all options and pursue non-utility solutions when they are more cost-effective.
- b. Real costs for electricity decline over the long term as utilities and customers are incentivized to make choices that optimize the alignment between generation and load to better utilize the existing system.
- c. Financial incentives (positive or negative) drive utility performance. High-performing utilities may earn more than their costs would indicate, and utilities that do not meet performance outcomes may earn less.

- d. A more customer-centric framework that meets growing customer expectations regarding service, product, and technology options and includes affordable services to low-income customers.

Through the discussions in phase II, however, it became clear that there are diverging views as to how quickly and how extensively the shift should take place, even though there was agreement among participants that there is value in moving toward a more performance-based model. A sudden and untested shift away from the current risk-reward relationship could potentially have an adverse impact on utilities' ability to make necessary cost-effective investments in the electric system. Similarly, waiting too long to act could be detrimental. As a result, e21's white paper *Performance-based Compensation Framework* delineates principles, guidelines, potential outcomes, and metrics to support an incremental movement toward a more performance-based model, but does not choose among three identified stages or recommend specifically where Minnesota's regulatory framework should settle. e21 participants acknowledge that there may be other options, but agreed that the three models listed below are illustrative of the choices that utilities and regulators will have:

1. **Current cost-of-service model.** In this scenario, earnings from capital investment remain the primary driver for utility shareholder value. Any performance- or outcome-based financial incentives would be in addition to the utility's cost-based revenue requirement and considered separately from a rate case.
2. **Partial shift to a performance-based compensation framework.** In this scenario, the regulator-authorized return on equity is reduced, and utility earnings are driven by a combination of performance outcomes and capital investments. The relative share of earnings coming from each would be determined over time. Shareholder earnings may also include potential new revenue streams from providing new products and services.
3. **Shift to performance-based compensation framework.** Here, there is no automatic, regulator-authorized return on equity; utilities still recover their costs, but shareholder returns would be earned through a combination of utilities achieving performance goals and possible new product and service revenue opportunities.

In all of these scenarios, it is assumed that utilities would recover their prudently incurred costs, including stranded costs as determined by the Minnesota PUC. Thus, whereas in scenario 1, a utility would get a return on its capital investment and have the ability to earn more if it meets certain milestones (for example, achieving a power plant retrofit under budget, delivering greater grid reliability, or adding more choices for customers on how their electricity is produced, such as from wind), in scenario 3, the utility does not earn anything above its costs unless its performance dictates.

The white paper then goes through a list of nine potential performance outcomes, detailed explanations, and sample metrics for each. The metrics for each outcome are not meant to be exhaustive and would need additional exploration, as would the outcomes themselves. e21 offers the following performance outcomes for consideration:

- a. distributed energy resources and grid services are fairly valued and integrated into the electric system in ways that add net benefits and minimize costs
- b. utilities have sufficient incentive to manage controllable costs, particularly operations and maintenance

- c. the system is made more efficient
- d. reductions are achieved in the pollution and carbon emissions in any part of the energy economy in a cost-effective manner beyond what is required in law
- e. electricity customers, including low-income customers, have increased access to a wider range of utility and third-party services and products
- f. development of efficient, low/no carbon loads (e.g., electric vehicles) is promoted
- g. high levels of reliability are ensured as driven by customers, as and where needed
- h. customer satisfaction is increased
- i. customers are ensured access to basic electricity service that is affordable

The white paper is meant to be a guide for further study as utilities and policymakers seek to implement a performance-based system.

Integrated Systems Planning

In phase I, the e21 participants recommended changes to the resource planning process for utilities that opt in to a performance-based multi-year rate structure. Those utilities opting to file a performance-based multi-year rate plan would revise their traditional approach to the 15-year integrated resource planning regime by focusing more attention on the five-year action plan portion and by streamlining regulatory review of the later years of the resource plan (beyond the action plan period). The phase I report referred to this as an integrated resource analysis.

In addition, the e21 participants recommended including more information about transmission and distribution wire and non-wire alternatives in a resource plan, such as additional demand response capabilities and other distributed resource options. This would enable a more detailed look at the ways to serve load that includes both utility-sited and customer-driven resources.

In phase II, e21 refined its thinking about how the traditional integrated resource planning process might evolve and now recommends transitioning the traditional long-range planning process to an integrated systems plan for *all* utilities rather than only those opting in to a multi-year rate plan, because the need to evolve resource planning to take a broader set of distributed and transmission system alternatives into account is important to everyone affected by the distribution system.

e21 participants believe that the resource planning process has served the needs of Minnesotans well over the years, and they see their proposed changes as simply a continuation of the adaptations that have been made in the past to ensure that this least-cost planning process continues to promote the public interest as the electric sector and utilities evolve to suit 21st century needs.

The key question of the current resource planning process will remain how to ensure that customer needs are met in the least-cost ways to achieve relevant state and federal requirements. In addition, those who are engaged in integrated systems planning will need to begin asking and thinking about answers to the following questions:

- a. What is the projection for development of demand-side resources, including both customer-driven generation and customer demand response, that are outside the utility's control?

- b. What additional potential exists for customer- and utility-sited distributed energy resources to cost effectively meet system needs? Facilitating that potential may require changes to rate design, procurement programs, and other proactive measures.
- c. What are the opportunities for third parties in the provision or aggregated operation of those resources?
- d. How might supply-side and demand-side resources interact in real time to optimize past and future investments in order to reduce customer cost impacts over the planning period?
- e. How does the integrated systems plan of a given utility meet Minnesota's needs and public policies, as well as coordinate with the plans of other utilities and the Midcontinent Independent System Operator (MISO) electricity market?

To facilitate the answers to the questions above, the e21 participants outlined four main areas of potential improvement to the resource planning process:

- a. optimize the length of time during which a plan is processed through the regulatory system, and better manage the administrative burden that is placed on regulators, staff, and other parties
- b. expand the scope of the planning process to take more of an end-to-end systems approach (from the bulk transmission level to the distribution grid)
- c. include more timely information about utility costs and customer impacts from various approaches to the resource mix, infrastructure investments, and delivery mechanisms
- d. improve the balance in the plan review process between reliance on modeling versus policy and strategic considerations

The integrated systems planning white paper sets forth an explanation of the current regulatory process and then, using the above questions and areas of improvement, describes potential modifications. They are:

- a. **pre-filing collaboration**, to create understanding and potential agreement around modeling assumptions, resource costs, and planning scenarios and sensitivities. This will help reduce the number of issues that significantly impact the evaluation of resource plan options
- b. **standardization of naming conventions**, for what constitutes a base case, a reference case, a preferred plan, and other commonly used terms
- c. **identification of best practices**, used by utilities in Minnesota, to be shared on a regular basis
- d. **standardization of modeling techniques**, to be used by Minnesota utilities and intervenors, such as how variable and distributed resources, demand response, and energy efficiency resources should be modeled
- e. **holding annual/biennial systems planning workshops**, to discuss planning, modeling, and forecasting issues; share best practices; and consider new policies and planning requirements and MISO market impacts

- f. **coordination by the Minnesota PUC of the scheduling of rate cases and resource plans**, as a pre-cursor to a utility business plan for those utilities that opt to file a multi-year rate plan
- g. **establishment of regulations for utility business plans by 2020**, in order to allow utilities to opt in to such a plan
- h. **evaluation of supplemental modeling platforms**, which could provide better near-term integration of demand-side resources and customer-owned generation with supply-side resources
- i. **provision of more information about demand-side resources and capabilities**, including better forecasting of resources over the planning period and information about potential interactivity with utility resources
- j. **evaluation of the usefulness of potentially outdated planning requirements**, such as the requirement for 50/75% renewable capacity scenario
- k. **compliance with the Clean Power Plan**, analyzing how a utility's resource decisions might affect compliance with the plan
- l. **determination of the five-year rate impact of key scenarios**, as identified by the pre-filing collaboration. This would be in addition to the overall rate impact of the preferred plan and the traditional comparison of their revenue requirements (measured in present value)
- m. **evaluation of innovative options to increase system efficiencies and cost-effectiveness and achieve environmental goals**, including deferred investments, easing of rate impacts over time, value-of-solar pricing, time-of-use rates, dynamic pricing, system efficiencies made possible through grid modernization, and coal ramp-down with renewable ramp-up

Implementing these regulatory changes would help facilitate the goals outlined in e21's phase I report while also being respectful of the role that regulators must play. By encouraging greater collaboration on the resource planning side, these changes will also make it easier to implement the changes proposed in the other white papers and to do so in ways that reflect the myriad interests that are affected by Minnesota energy policy.

These suggested changes do not, however, obviate the need identified in phase I to modify the resource planning process to account for multi-year rate plans lasting up to five years. Again, how this occurs would need to be addressed by the Minnesota PUC in general dockets.

Grid Modernization

The basic design of the electric grid has remained largely the same since the first commercial power plant in the United States went into service in 1882. Electricity has for the most part been generated by large central stations, transmitted large distances over high voltage transmission lines, and then reduced in voltage for local distribution and delivery to customers. The vertically integrated system is now changing, evolving to be cleaner and more efficient and to integrate more renewable resources in a cost-effective manner. In addition, customers are installing their own electricity generation, whether on rooftops or through on-site power plants.

Today, the distribution system needs to be able to manage two-way flows of both electricity and information, taking in power and data generated from these customer sites and coordinating many more actors on the system. A modern grid must adapt to increasing distributed energy resources such as storage, electric vehicles, microgrids, combined heat and power, small wind, demand response, and other sources. In short, we are headed for a much more distributed, networked grid that needs to be able to respond to rapidly changing technologies.

Recognizing that a modernized grid provides many benefits to customers, utilities, and grid operators, the phase I report recommended that Minnesota:

- a. develop a transparent, forward-looking process for modernizing the grid (which the Minnesota PUC has underway)
- b. identify how to achieve a more flexible distribution system that can efficiently and reliably integrate cost-effective distributed energy resources
- c. pursue opportunities to reduce customer and system costs by improving overall grid efficiency and better utilizing existing system assets (improving the grid's load factor)

Toward these ends, the grid modernization white paper does the following: suggests an overall approach and a set of objectives for grid modernization in Minnesota, outlines the functions and technologies needed to achieve those objectives, and offers recommendations and next steps that can usefully complement the Minnesota PUC's on-going grid modernization process. The five grid modernization objectives identified by the e21 group are:

Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed, through such things as establishing cost-effective, real-time ways to anticipate and fix problems on the system; mapping where on the distribution grid distributed energy resources can provide the greatest benefit and using price signals to encourage them to locate in those places; and deploying sophisticated communications technology to coordinate all of the actors on the electric grid while protecting privacy and ensuring cybersecurity.

Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers, including through deployment of advanced meters and improved customer access to their own electricity usage data (usage and price).

Objective 3: Enhance the system's ability to integrate distributed energy resources and other new products and services in a cost-effective and timely way, by such means as conducting thorough and regular distributed energy resource "hosting capacity" and "locational value" analyses, improving access to that and other relevant grid-level information, and updating Minnesota's interoperability standards and interconnection processes.

Objective 4: Improve the environmental performance of electricity services, by creating a physical and information technology platform that can optimize the environmental performance of the electric system as a whole—drawing on all available resources to do so, from large-scale renewable generation to responsive customer loads—integrating more renewable energy into the system and better measuring energy savings from efficiency programs.

Objective 5: Promote optimized and cost-effective utilization of grid assets, through reducing peak demand and utilizing both customer-driven resources and the utility's resources

to meet demand at a given time, without overbuilding the distribution grid or power generation sources.

To further these objectives and manage the complexity of this wide-ranging area, the e21 group makes 14 recommendations, organized into three categories. ***The recommendations are addressed to regulators unless otherwise noted.***

Planning

- a. **Provide guidance on developing standard information sets and platforms for the sharing of hosting capacity**
- b. **Review and update Minnesota's interconnection standards and processes to make the interconnection process more predictable, transparent, timely, and consistent**
- c. **Distribution planners employ scenario planning to manage the inherent uncertainty of planning for the unknown number, scale, and location of distributed energy resources on the distribution system**

Customer Services and Engagement

- d. **Use a multi-interest stakeholder process to determine the services and benefits (including environmental benefits) that distributed energy resources receive from the grid and can provide (including environmental benefits) to meet the electric grid's needs**
- e. **Establish price signals and payment options that direct distributed energy resources to optimal locations on the grid and that encourage customers to optimally time their electricity use**
- f. **Provide customers with convenient and timely access to as much of their own data as possible in a consistent format to enable customers to make informed decisions about the timing and amount of their electricity use**
- g. **The Minnesota PUC takes steps it deems necessary to ensure that utilities implement best practices in all areas of cybersecurity to ensure the availability and confidentiality of information and the integrity and security of the electric system**
- h. **Allow utilities to establish a specific budget to conduct research and development, rather than relying solely on pilot programs to innovate**

Operations

- i. **Ask utilities to adopt cost-effective voltage and volt-ampere reactive optimization appropriate for each utility's system**
- j. **Draw on the existing body of regulation and experience to develop a strategy to utilize smart inverters**
- k. **Establish procedures and tariffs for how and when a distribution grid operator may dispatch and curtail distributed energy resources to enable the near real-time**

matching of generation and load using both supply-side and demand-side resources

- l. Implement appropriate and cost-effective enabling technologies that are prerequisites to achieving grid modernization objectives** (e.g., supervisory control and data acquisition, advanced metering infrastructure, and high-speed and high-capacity communication systems)
- m. Ensure the use of national standards necessary for effective integration of distributed energy resources and interoperability of the grid's communication systems**
- n. Use digital, automated communication, and monitoring technologies to more accurately evaluate the environmental impact and effectiveness of efficiency and clean electricity programs**

As noted above, the Minnesota PUC has initiated a process to explore grid modernization, and the e21 group wishes to complement and inform its process. To that end, the e21 Initiative will identify opportunities in upcoming dockets to address foundational “no regrets” actions; take up issues for which the PUC’s technical workshops would have difficulty fostering ongoing dialogue and feed information back into the commission’s process; and take up issues beyond the commission’s current focus with the goal of offering definition and depth on topics likely to be considered in the future.

Accomplishing these next steps will require close coordination with PUC commissioners and staff, and will be assisted by the process changes for e21 discussed in Appendix A.

Interrelated Nature of the e21 White Papers

Each of the three white papers summarized above attempt to answer a different fundamental question: *Performance-based Compensation Framework* explores how we might base at least a portion of utility earnings on utilities’ achievement of particular outcomes rather than simply how much capital they invest in infrastructure to serve electricity customers; *Integrated Systems Planning* examines how we might change the way we conduct long-range electricity planning to improve administrative efficiency and better account for what’s happening at the “distribution edge” where solar and other distributed energy technologies are becoming more common; and *Grid Modernization* sheds light on how we’ll need to invest in, plan for, and operate a more complex and dynamic distribution grid that can cost-effectively integrate a wide variety of emerging distributed energy resources while continuing to ensure safe, reliable, affordable electricity. This trend toward decentralization is not to the exclusion of large power plants, but in addition, making it crucial that we plan ahead for how they will work together.

Since virtually every aspect of the electric system impacts all the others, it almost goes without saying that making changes recommended in one white paper will necessarily invite discussion of the others, and of the net effect on customers and the electric system as a whole. Not only individual decisions themselves, but the process of how and when decisions are made, all have ripple effects on the rest of the electric system and on regulatory outcomes.

An example might be a decision to move to a performance-based compensation system for utilities, with compensation based in part on the number and duration of power outages. That would surely induce the utility to include in its investment and operational plans those measures

it deemed necessary to achieve the reliability targets. It would also likely stimulate changes to the physical grid itself in terms of technology, hardware, operations, and maintenance, thus intersecting with the issues and opportunities discussed in e21's grid modernization white paper. Finally, grid improvements that reduce the number and duration of power outages will inevitably create a new baseline of performance against which the next future-looking Integrated System Plan will be judged, and perhaps even influence what the "preferred plan" looks like.

Taken together, the e21 white papers are intended to contribute to building a more modern, adaptable electric system that provides cleaner electricity and more customer options without sacrificing reliability or cost-effectiveness, the goals embodied in the *e21 Initiative Phase I Report*.

Common Themes

In addition to the e21 guiding principles listed above, the three white papers also illuminate a number of common themes that will be important as Minnesota moves forward.

First is the **value of real-time, multi-interest discussion and negotiation in advance of formal proceedings**. e21 itself demonstrates this theme. Having a regular platform for mutual learning and collaboration among interested parties can be a valuable complement to the publicly noticed regulatory proceedings carried out under the auspices of the Minnesota PUC.

A second theme is the necessity of **new approaches to planning**. This includes considering new questions that weren't part of the planning calculus before—such as what amount of DERs can a given feeder host, and where are the best places for DERs to go—and new analytical tools that allow planners to anticipate what level of DER penetration can be expected and in what time frame. A new approach to planning is also embodied in e21's recommendations for multi-year rate plans that give utilities "more running room" (up to five years) in exchange for business plans that clearly set forth what outcomes they will achieve over that time frame, how, and at what cost.

The other themes that repeatedly emerge from e21's work are those of **transparency** and **streamlining of processes**. Each is necessary for a more modern grid. Examples include: simplicity and transparency around the process for interconnecting to the grid, and finding the right balance between access to energy use data and information that would allow DER providers to locate in optimal places on the distribution grid, all while protecting privacy and cybersecurity. Transparency is also necessary for any streamlining of regulatory processes, as those processes, while sometimes seen as cumbersome and costly, also emerged in large part to protect the interests of the vast majority of people who have neither the time nor inclination to participate directly in the regulatory decision-making process with respect to the electric grid. Interestingly, streamlining processes may also *contribute* to greater transparency, as standardizing processes (as recommended in the integrated systems planning white paper) could reduce costs for intervenors and utilities (costs that are paid by customers) and provide a better understood basis for decision-making.

Finally, the three white papers all suggest **viewing the electric distribution system as a place of dynamic change and new source of value**, taking a **measured approach to reform**, and **preparing the system for adaptation** to relatively more rapid change. As this report and the phase I report both point out, the electric distribution system has been relatively unchanged for some 130 years. As technology changes, and customer interaction with the system changes, we need a regulatory system and utility business models that not only accommodate today's changed circumstances but allow for innovation in the future. We are already experiencing this

need for adaptation as adoption rates climb for technologies such as rooftop solar, electric vehicles, and energy storage.

As a whole, the e21 phase II white papers represent the collective wisdom of a diverse set of interests in Minnesota on how Minnesota can respond effectively to the forces that are reshaping the electricity sector—to prepare our electric system to meet society’s needs as well in this century as it has in the last.

Appendix A: Where from Here

The e21 Initiative has undertaken a holistic examination of regulatory and utility business model reform in Minnesota. In its phase I report, e21's diverse group of participants set out a new blueprint for both, including guiding principles and consensus recommendations for responding to a wide range of pressures on the electricity sector. If phase I offered a blueprint, phase II has been about beginning to build the house. This report aims to provide the next level of detail necessary to begin implementing changes in three areas outlined in phase I: integrated systems planning, grid modernization, and performance-based utility compensation.

e21's outcomes, in addition to providing a useful intellectual foundation for complex intertwined issues, are important because they represent a thoughtful discussion among a diverse set of interests. But because the e21 Initiative has been driven by its participants and has operated outside the formal regulatory structure, in its next phase there is a need to shorten the distance between a good e21 idea and its uptake and implementation by decision-makers. Moving forward, phase III needs to be designed for taking action and beginning the process of learning by doing.

To accomplish this, e21's co-directors are in the process of designing phase III, including restructuring how it functions in order to more deeply engage with regulators and regulatory staff, open the process to a wider range of interests, continue to meaningfully engage utilities, increase consumer advocate participation, and engage more extensively with national experts to best inform the e21 process.

Appendix B: Outside Speakers Who Presented to e21

Note: Outside speakers from phase II are listed by e21 meeting date and topic. Meetings listed below are only those that included an outside speaker. Some e21 meetings did not include outside speakers. Titles and organizational affiliation of speakers reflect a speaker's title and affiliation at the time of their presentation.

May 3, 2016

Topic: Distribution systems in a high distributed energy resources future: planning, market design, operation and oversight

- Paul De Martini, Senior Fellow, ICF

April 5, 2016

Topic: The future of resource planning

- Arne Olson, Partner, E3

February 26, 2016

Topic: Performance-based regulation in a high DER future

- Mark Newton Lowry, President, Pacific Economics Group

Topic: Stakeholder discussion on service quality metrics

- Jody Londo, Manager, Asset Analytics and Regulatory Reporting, Xcel Energy

December 18, 2015

Topic: Grid load management for the 21st century

- Eric Lebow, CEO, Power Over Time
- Ken Glaser, Energy Efficiency Coordinator, Connexus Energy
- Will Kaul, Vice President, Transmission, Great River Energy

November 23, 2015

Topic: Financial foundations for electric utility strategy in a changing environment

- Steve Kihm, Principal and Chief Economist, Seventhwave

Topic: Economic frameworks for analyzing market structure changes and institutional response in the electric utility industry

- Steve Corneli, Senior Vice President, Policy and Strategy, NRG

October 23, 2015

Topic: Understanding the consumer

- Kenneth Black, Co-chairman, E Source
- Mathias Bell, Manager, Market Development and Regulatory Affairs, OPower

September 18, 2015

Topic: Consumer perspectives

- Ron Elwood, Supervising Attorney, Legal Services Advocacy Project
- Will Phillips, State Director, AARP Minnesota

August 17, 2015

Topic: Overview of existing rate structures to develop a shared understanding of what's in place today and examples (including rate design pilots) of the outcomes that are encouraged

- Kate O'Connell, Manager, Energy Regulation and Planning, Minnesota Department of Commerce, Division of Energy Resources
- Chris Villarreal, Director of Policy, Minnesota Public Utilities Commission
- Marcia Podratz, Director—Rates, Minnesota Power
- Amy Liberkowski, Manager, Pricing and Planning at Xcel Energy

Topic: New York Reforming the Energy Vision (REV) update & discussion of their approach to rate reform

- Dan Cross-Call, Manager, Electricity Practice, Rocky Mountain Institute

June 24 2015

Topic: Integrated resource planning in Minnesota

- Janet González, Division Manager, Regulatory Analysis, Minnesota Public Utilities Commission
- Chris Shaw, Analyst, Minnesota Department of Commerce, Division of Energy Resources

Topic: Utility resource planning

- Jon Landrum, Manager, Resource Planning Analytics, Xcel Energy
- Eric Palmer, Resource Planning Technical Analyst Senior, Minnesota Power
- Laureen L. Ross McCalib, Director, Resource Planning, Great River Energy
- Brian Draxten, Manager, Resource Planning, Otter Tail Power

Topic: Discussion on today's integrated resource planning process

- Beth Soholt, Executive Director, Wind on the Wires

Topic: Leading edge thinking on planning for a different system

- Jim Lazar, Senior Advisor, Regulatory Assistance Project
- Lorenzo Kristov, Principal, Market & Infrastructure Policy, California Independent System Operator

May 29 2015

Topic: What performance areas do utilities currently track and what data is used?

- Carolyn Brouillard, Manager, Regulatory Policy, Xcel Energy (now Distributed Energy Resources Regional Manager, ICF)
- Jennifer Peterson, Policy Manager—Regulatory Affairs, Minnesota Power

Topic: Performance-based regulation (including principles for design, case studies, and emerging performance areas)

- Sonia Aggarwal, Director of Strategy, Energy Innovation LLC
- Melissa Whited, Senior Associate, Synapse Energy Economics, Inc.

April 24, 2015

Topic: Distribution system overview (design, operations, key performance metrics), distribution system planning process, and grid modernization

- Brian Amundson, Manager, Distribution System Planning and Strategy, Xcel Energy
- Craig Turner, Manager of Distribution Engineering, Dakota Electric Association,
- Reed Rosandich, Supervising Engineer, Distribution System Engineering, Minnesota Power

March 6, 2015

Topic: Introduction to grid modernization

- Matt Schuerger, President, Energy Systems Consulting Services, LLC

Appendix C: e21 Outreach Activities

- e21 participants have presented frequently across the country, including to the following organizations and groups:
 - American Council for an Energy Efficient Economy
 - American Legal Educators (first annual sustainability conference)
 - American Public Power Association (annual meeting)
 - American Public Works Association
 - Association of Climate Change Officers
 - Association of Energy Services Professionals
 - British Embassy-organized event highlighting the UK's RIIO and other utility reform options
 - Clean Energy States Alliance (national meeting)
 - Edison Electric Institute
 - Electric Power & Light (executive conference)
 - Energy Bar Association, Midwest Chapter (annual meeting)
 - EUCI
 - Faegre Baker Daniels (Washington, D.C., office)
 - Grid 3.0 workshop
 - IEEE Power & Energy Society (Innovative Smart Grid Technologies conference)
 - Minnesota Chamber of Commerce
 - Minnesota Renewable Energy Association
 - National Governors Association
 - Northwest Efficiency Exchange
 - Otter Tail Power Company's senior management team (as part of their strategy process)
 - RE-AMP
 - University of Pennsylvania (utilities conference)
 - Women of Wind Energy coalition
- e21 participated as a team in the Rocky Mountain Institute's eLab Accelerator (in 2014, 2015, and 2016), a national "innovation boot camp" for those exploring how a 21st century electric system might work. Each time the e21 team had the opportunity to interact with, and learn from, about a dozen other related efforts from the U.S.
- The Great Plains Institute led a webinar series for the Midwestern Governors Association on utility business model reform in 2016 that culminated in an in-person meeting. The work was supported by the association through its funding from the U.S. Department of Energy (DOE) and built on expertise generated through e21's work.
- The George Washington University Law School convened decision-makers and stakeholders from disparate parts of the U.S. in October 2016 to discuss transformation of the U.S. electric system. Work of the e21 project was highlighted, together with initiatives from California, the southeastern part of the U.S., the Federal Energy Regulatory Commission, North American Electric Reliability Council, and U.S. DOE, with additional perspective from representatives of the solar, storage, and data management sectors, an advocate for low-income consumers, and an expert in grid architecture.

Appendix D: Additional Resources

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White Paper: Performance-based Compensation Framework

Introduction

To modernize the traditional utility business model in light of industry changes and Minnesota's public policy goals, e21 set forth in its first phase two big goals:

- *Shift away from a business model that provides customers few options (everyone gets the same grid electricity produced largely with coal, natural gas, or nuclear power at large central stations) toward one that offers customers more options in how and where their energy is produced and how and when they use it, while maintaining fair and competitive pricing, reliability, and minimal environmental impacts*
- *Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want*

This shift is meant to encourage a least-cost, best-value⁴ approach to achieving agreed-upon performance outcomes that includes consideration of both central station and distributed energy resources in meeting electric system needs.

Utility regulation is based upon a regulatory compact,⁵ having two facets. First, utilities accept an obligation to serve all customers requesting service in return for a monopoly franchise in a given area. Second, utilities are allowed an opportunity to recover, and earn a reasonable rate of return on, the prudent capital investments that are reasonable and necessary to serve its captive customers. When a utility believes its sales revenues are no longer sufficient to recover these costs, the utility can petition to increase rates with the agency having jurisdiction over its operations. In the case of Minnesota, that agency is the Minnesota Public Utilities Commission (PUC). Other Minnesota government agencies that also participate in this process include the Minnesota Department of Commerce and the Minnesota Office of the Attorney General. In general terms, a utility rate case has two sets of issues: (1) the revenue requirement—how much rates should increase according to an analysis of the utility's filed cost of service, and (2) the revenue allocation—who pays for the rate increase ultimately resolved under (1).⁶

Although there are exceptions and policy considerations, the general rule under Minnesota state law is that rates set by the Minnesota PUC must be just and reasonable. This has historically meant that rates are based on cost of service balanced against other non-cost factors. In other words, rates are intended to reflect the cost of the fuel needed to produce electricity and the cost of building, operating, and maintaining the system of power plants, wires, poles, and equipment to generate and deliver electricity. Under this current cost-of-service model, it is largely the utilities' investment of capital that drives utility earnings and shareholder value.

⁴ "Least cost, best value" includes the analysis of desired outcomes and then the search for methods that will achieve those outcomes at the lowest cost for customers.

⁵ Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, Va.: Public Utilities Reports, Inc. 1993).

⁶ *Id.*

Because utilities rely, in part, on financial markets to fund capital improvements, investors are an important part of the utility's business. Generally speaking, financially strong companies are able to borrow money at lower interest rates; therefore, assuming a utility is recovering its prudent investments with a reasonable rate of return, the utility should remain financially strong. All else being equal, a financially healthy utility is able to provide service at a lower rate than a less financially healthy utility.

Cognizant of the interplay between financial health of the utility, cost-of-service regulation, and utility rates, e21 proposed in its phase I that Minnesota evolve this model toward a performance-based approach to utility compensation—an approach that would tie a portion of a utility's earnings to their achieving an agreed-upon set of performance metrics. Such a compensation system will enable utilities, regulators, and stakeholders to work together proactively to define the outcomes they want utilities to deliver—such as greater energy efficiency and customer access to more utility and third party products and services—and then compensate utilities appropriately while maintaining rates that are competitive and affordable. In short, a performance-based approach provides utilities a clear financial incentive to produce the outcomes valued by customers, policymakers, and regulators.

To implement this performance-based approach, e21 proposed in its first phase that Minnesota provide an option for utilities that opt in to work collaboratively with stakeholders and regulators to develop a performance-based multi-year rate plan that integrates a range of planning, policy, and rate issues and results in a cohesive package that will support the achievement of the selected performance outcomes and policy goals. A multi-year rate plan fits very well with a more performance-oriented regulatory framework, since it may take a utility a few years to set in motion new business activities that result in the desired performance outcomes, some of which may be measured for the first time. Benefits of this approach include that

- a. utilities are incentivized to achieve outcomes aligned with customer needs and expectations
- b. multi-year rate plans give utilities sufficient time to achieve the public outcomes they commit to in the plan
- c. utilities are encouraged to choose the least-cost, best-value option for achieving any particular outcome—regardless of whether or not doing so requires capital, third-party, or operational expenditures
- d. multi-year rate plans could provide more predictable rates for customers
- e. multi-year rate plans could reduce the frequency and cost of rate cases, which are a challenge for utilities and intervenors under the current regulatory approach

In phase I, e21 participants recommended an option for utilities to file a business plan, covering a period of up to five years. The plan would describe the utility's proposed investments and anticipated decisions over that time frame and, where applicable, how it would achieve the desired performance outcomes. The plan would include the five-year action plan that is currently produced as part of the 15-year integrated resource plan, but is now proposed to be developed as part of the collaborative business plan process instead, though still informed by the integrated resource plan.⁷ Additional required components of the business plan would include, at a minimum:

⁷ Shifting the development of the five-year action plan may require statutory change.

- a. rationale and evidence for the requested revenue requirement
- b. a process for adjusting rates during the plan period⁸
- c. the rate designs that will collect the approved revenue

The business plan may include other features as well, including incentives and processes for cost control, cost review and reconciliation, and for accurate financial forecasting.

New Statutory Language on Multi-Year Rate Plans

In 2015, the Minnesota legislature modified the existing multi-year rate plan statute (Minnesota statute § 216B.16, subd. 19) to allow for the extension of rate plans from up to three years to up to five years and to provide greater flexibility and further guidance regarding the permissible features of a multi-year rate plan. Some of the key amendments to the statute include:

- a. A utility proposing a multi-year rate plan must provide a general description of the utility's major planned investments over the plan period.
- b. The Minnesota PUC may require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies.**
- c. The PUC may allow the utility to adjust recovery of its cost of capital or other costs in a reasonable manner within the plan period.
- d. Recovery of the utility's forecasted rate base may be based on a formula, a budget forecast, or a fixed escalation rate, individually or in combination.
- e. Recovery of operations and maintenance expenses may be based on an electricity-related price index or other formula.
- f. The plan can include tariffs that expand the products and services available to customers, including, but not limited to, an affordability rate for low-income residential customers.
- g. A plan can also provide for adjustments to the rates approved under the multi-year rate plan for rate changes that the PUC determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan.

One focus of this white paper is the second bullet in bold above—identifying reasonable performance measures that can be implemented as part of this statutory framework.

⁸ With the current volatile landscape in the electricity sector, there must be flexibility and a means to consider significant policy changes that come about in the middle of a period.

Charge to the Performance-based Compensation Subgroup

This paper is an initial attempt to scope potential outcomes and metrics for a performance-based compensation framework for utilities. The identified metrics are intended to be illustrative and are not exhaustive. e21's goal was to provide some early thinking to help guide future conversations. Similarly, we acknowledge that many implementation questions associated with a shift to a more performance-based model remain to be answered. The main body of the paper is organized in sections as follows:

- I. Overarching Objectives of a Shift to Performance-based Compensation
- II. Different Models or Stages of Reform
- III. Role of Performance Mechanisms
- IV. Principles for Selection of Performance Outcomes and Metrics
- V. Potential Performance Outcomes and Associated Metrics

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Section I:

Overarching Objectives of a Shift to Performance-based Compensation

With the new statutory framework in mind, this white paper offers the following objectives that e21 believes address, at a high level, what a performance-based regulatory model should achieve over the long term.

- a. The central objective of a performance-based regulatory framework is to shift away from a regulatory system that primarily rewards increasing the sale of electricity and building capital-intensive facilities and infrastructure, and toward a system that rewards utilities for delivering public policy outcomes and meeting customers' service expectations.
- b. This shift is also intended to achieve the following core objectives:
 - i. Utilities become indifferent to how a particular system need is met (e.g., large central generation or distributed generation) and by whom (utility or non-utility). Utilities would evaluate all options and pursue non-utility solutions when they are more cost-effective.
 - ii. Real costs for electricity decline over the long term as utilities and customers are incentivized to make choices that optimize the alignment between generation and load to better utilize the existing system.
 - iii. Financial incentives (positive or negative) drive utility performance. High-performing utilities may earn more than their costs would indicate, and utilities that do not meet performance outcomes may earn less.
 - iv. A more customer-centric framework that meets growing expectations of customers regarding service, product, and technology options, including providing affordable services to low-income customers.

This shift will be driven by more directly tying a portion of utility earnings to performance that is quantifiable, verifiable, and aligned with e21's guiding principles, as opposed to returns solely based on capital investments. The shift should be gradual and allow for the utility to maintain a viable and reasonable financial position as the framework evolves over time. As with all of the components considered under the performance-based compensation approach, the existing requirements that rates be "just and reasonable" and "free from unreasonable preference, prejudice, or discrimination" will be preserved and will continue to be subject to Commission interpretation and determination, as stated in Minnesota statute 216b.03.

Consistent with our phase I recommendations, e21 agrees there is value in moving toward a performance-based model that creates a stronger link between utility compensation and achievement of outcomes. In addition, the group agrees that this shift will occur over time, likely adding features and increasing the share of earnings tied to performance as experience is gained.

Minnesota is well positioned to enact this shift, as it has a history of using performance mechanisms to encourage utilities to take certain actions. For example, the Department of Commerce's Conservation Improvement Program incentive shares the net benefits of utility demand-side management programs between the utility and customers, such that a utility can

increase its earnings by increasing the energy savings achieved through its programs. As such, this mechanism has led to a significant increase in energy savings and net benefits for customers. Additionally, the Metropolitan Emissions Reduction Program included a performance incentive that varied the return on equity on qualifying projects based on actual incurred costs, such that a utility completing work under budget resulted in a higher return on equity and vice versa.⁹ Minnesota can draw on these experiences as it considers expanded changes to the regulatory framework and the use of performance mechanisms.

In addition, regardless of how this shift may change the sources of utility earnings, this transition should also ultimately incorporate and be informed by resource planning processes. Consistent with e21's phase I recommendations, utilities should evaluate how to best pair the timing of the revised integrated systems plan with the five-year business plan and multi-year rate plan filings. For example, a utility that files an integrated systems plan in 2020 would file a multi-year rate plan and five-year business plan at the same time. The five-year action plan that is currently part of the integrated resource plan would be included in the multi-year rate plan and five-year business plan and subject to full regulatory review.

This effort could also encompass what otherwise might require one or two rate cases during the same time period. The scheduling and consideration of the order of submissions should be determined by the Minnesota PUC and stakeholders in the regulatory process. Stakeholders would address whether to require such filings every five years or some other agreed-upon schedule.

Finally, it is important to acknowledge that a shift to a more performance-based system under a multi-year rate plan may require additional statutory and/or procedural changes to allow efficient coordination among resource planning and the multi-year rate plan. In addition, this shift will likely require regulatory resources to be deployed in a new way. This may require different or broader tools and skills for regulatory staff to effectively evaluate utility plans, including an increased need for consideration of performance metrics and targets as part of the overall revenue requirement. Similarly, additional regulatory staff may be needed to process the multi-year rate plan and associated reporting.

Section II:

Different Models or Stages of Reform

Table 1 represents three points along a continuum of reform, with the degree of change increasing from column 1 to 3. It is intended to provide three representations of what a shift might look like at different stages or manifestations, but should not be read as prescriptive, exhaustive, or necessarily sequential. There is a diversity of views among e21 participants as to when moves would take place and how best to implement change.

⁹ See settlement agreement filed December 11, 2003, in Minnesota Public Utilities Commission Docket No. E002/M-02-633.

Table 1: Potential Continuum of Reform

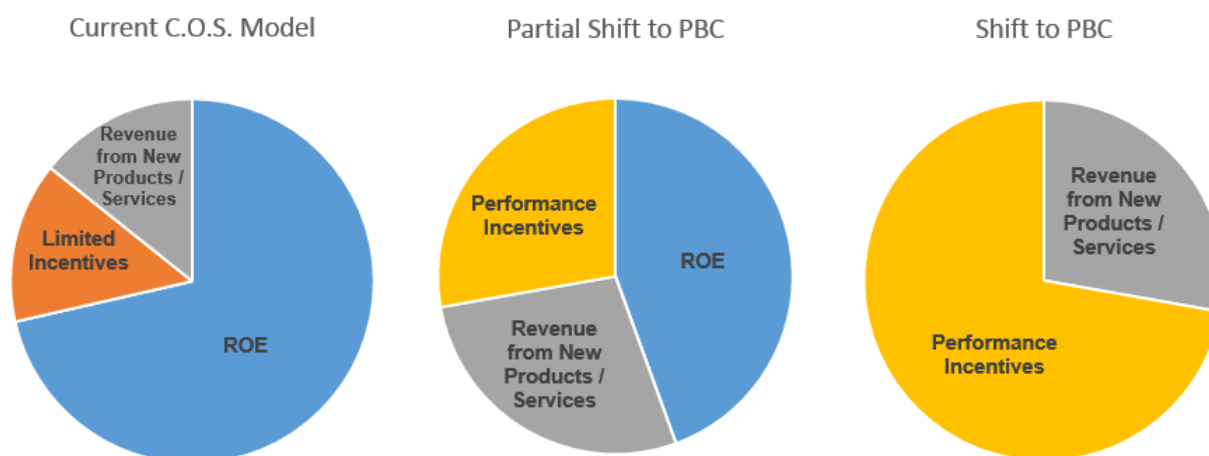
	(1) Current Cost-of-Service Model + Limited Incentives	(2) Partial Shift to Performance-based Compensation	(3) Shift to Performance- based Compensation
General Description	<p>This alternative would maintain Minnesota's current cost-of-service regulatory framework, but add limited performance incentives for particular policy outcomes that are not incentivized by the current system. The Conservation Improvement Program incentive is an example of an existing performance incentive. Similar tools could be used to target other outcomes. For example, increased adoption of distributed energy resources was identified by e21 as another potential targeted area for performance incentives. Another example could be a return on equity band on specific types of investments, similar to the Metropolitan Emissions Reduction Project.</p> <p>In this alternative, utility earnings from performance are incremental to returns set in a rate case.</p>	<p>This alternative would be a hybrid approach of the current cost-of-service model and a performance-based framework. It would allow utility earnings to be derived from a combination of returns on capital investments and from performance outcomes. The net effect encourages utilities to achieve performance goals, but maintains a return on capital expenditures.</p> <p>In this alternative, the potential for performance incentives and/or penalties is addressed in a rate case.</p>	<p>This alternative would be a change from the current cost-of-service model to a model where utility shareholder value is based on utility performance. This framework seeks to reduce or eliminate incentive for capital expenditure as the driver of shareholder value, and instead incentivizes utilities to achieve agreed-upon outcomes using whatever means best achieves them. However, it does not seek to <i>disincentivize</i> utility capital investment, as utilities would still be allowed cost recovery for reasonable capital investments.</p> <p>However, to be clear, utility capital investments would not earn shareholder returns, but would recover the cost of financing. Shareholder returns would instead be earned through a combination of utilities' achieving performance goals and possible new product and service revenue opportunities.</p> <p>In this alternative, the potential for performance incentives and/or penalties is addressed in a rate case as part of a comprehensive package.</p>

Summary of Earnings Drivers	<p>Earnings from capital investment remain the primary driver for utility shareholder value. Performance incentives are additional.</p>	<p>Earnings are driven by a combination of performance outcomes and capital investments. The relative share of earnings coming from each would be determined over time.</p>	<p>Shareholder value is driven entirely by utility performance. Under this approach, one option is to link recovery of all equity-related costs to performance. Another option is to determine a cost of equity and allow that to be recovered as a financing cost through rates.¹⁰</p> <p>This alternative would also enable the utility to establish new revenues from new products and services. Net income from these new products and services could be an additional source of earnings.</p>
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¹⁰ There is disagreement among e21 participants as to whether the PUC-approved return on equity is greater than the utility's cost of equity.

The pie charts in Figure 1 provide illustrations of the differences between the three points along the continuum of reform. In the chart for the current cost-of-service model, incentives are in addition to the allowed return on equity. In the second, some earnings come from the return on equity and the balance comes from performance. In the third, earnings are based entirely on performance.

Figure 1. Sources of Utility Earnings under Three Scenarios



Note: In all of these scenarios, it is assumed that utilities would recover their prudently incurred costs, including stranded costs as determined by the PUC. These pie charts are only meant to illustrate conceptually where utility earnings would come from under each of the three scenarios, and do not attempt to indicate the precise size of each source.

Formula for Utility Earnings. In interpreting the differences between the models represented above, it is useful to reference the formula for utility earnings under cost-of-service regulation and then illustrate how the formula may change under the other two models. As noted above, these descriptions are illustrative and are not intended to preclude other strategies or mechanisms. The same is true for the formulas below.

RR = Revenue requirement

Weighting considerations

W_d = weighted percentage of debt based on utility's capital structure

W_e = weighted percentage of equity based on utility's capital structure

W_p = weighted performance toward goals (unless performance is simply binary)

Cost considerations

C_d = cost of debt

C_e = cost of equity

C_{roe} = return on equity over and above cost of equity, if any

Operating expenses (OE) = annualized expenses allowed by the Minnesota PUC for a given test year

Rate base = original cost of the utility's plant used and useful in providing service less accumulated depreciation

Performance considerations*

P_p = the percentage attached to a particular metric, which may get larger with a greater shift toward performance-based compensation

$P_n = \pm (W_p)(P_p)$

$P_r = \sum_{p=1}^P x$

X = the number of applicable performance metrics

*This is only an example of how performance might be calculated for illustration purposes; there are likely other ways to calculate and account for performance-related utility earnings.

1: Current cost-of-service model. Any additional performance incentives are considered outside the rate case and do not affect the revenue requirement. (They would be over and above the revenue requirement.)

$$RR_1 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times (C_e + C_{roe}))]$$

- Shareholder earnings come from a regulator-authorized return on equity plus limited incentives on top of that.

2: Partial shift to performance-based compensation framework

$$RR_2 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times (C_e + C_{roe}))] \pm (P_r \times RR_1)$$

- Shareholder earnings come from utility performance, a reduced return on equity, and potential new revenue streams from providing new services.

3: Shift to performance-based compensation framework

$$RR_2 = OE + [\text{rate base} \times (W_d \times C_d + W_e \times C_e)] \pm (P_r \times RR_1)$$

- Shareholder earnings come from utility performance and potential new revenue streams from providing new services.

In scenarios 2 and 3, the performance earnings are determined by calculating an aggregate performance rate (P_r) based on whether the utility met certain performance goals. That rate is

then multiplied by the traditional revenue requirement as would be calculated in scenario 1. Particularly as we shift from the traditional framework to a performance framework, this will help keep the performance component within a reasonable band of the revenue requirement (i.e., if the old RR was \$100,000,000, the performance calculation could be set such that it would not exceed plus or minus \$10,000,000, or some other discrete range relative to the RR).

Another scenario that the e21 group discussed was one in which utility earnings are, like in scenario 3, based entirely on utility performance, but utilities would recover all or part of their cost of equity via performance incentives. This means that authorized recovery of the cost of equity could range from 0 to 100%. The closer to 0% that it gets, the more the equity-related costs would be recovered via a utility's performance. Several e21 participants expressed concerns that such a scenario may be seen by investors as overly risky and have the unintended consequence of unacceptably raising the cost of capital. The impact of any shift toward a performance-based compensation framework will hinge on the size of the earnings opportunities available.

Section III:

Role of Performance Mechanisms

- There are several areas or situations where performance mechanisms may be beneficial to
- a. motivate further action on state and federal policy goals or other PUC-approved priorities
 - b. promote achievement of benefits at reasonable costs and milestones associated with new projects or initiatives
 - c. address specific areas of underperformance
 - d. benchmark against other utilities in fully regulated markets
 - e. ensure that utilities can continue to provide reliable service and other desired outcomes under the incentive structure, taking into account dynamic circumstances
 - f. offset disincentives that cannot be fully addressed by more fundamental solutions

When performance mechanisms are considered for any of these purposes, the central challenges are: 1) to be specific enough, up front, about the outcomes desired to avoid disputes after the fact as to whether the performance outcomes were achieved or not; 2) to choose metrics that accurately measure progress toward the desired outcomes; and 3) establishing metrics that are measurable and verifiable by the utility and others.

Section IV:

Principles for Selection of Performance Outcomes and Metrics

Here we offer basic principles to guide the selection of performance outcomes and performance metrics.

Performance outcomes should

- a. tie back to accomplishing the e21 guiding principles and outcomes
- b. tie back to state and federal policy goals
- c. represent areas that electricity customers value and deliver benefits to all customers
- d. prioritize areas of performance and metrics that are most important to regulators

Performance metrics should be

- e. clearly defined and transparent
- f. measurable and verifiable by any third party using available, high-quality data
- g. drawn from data already reported today, if possible
- h. reasonably within the utility's control
- i. simple and easy to interpret and communicate
- j. directly tied to the desired outcome
- k. agnostic on specific means to achieve the outcome

Additional considerations could include

- l. bearing in mind potential trade-offs and interactions between metrics
- m. allowing sufficient time to understand whether or not metrics are effective in measuring performance, thereby avoiding frequent changes to the metrics
- n. using pilot programs to encourage, and pave the way for, exemplary performance (that is, allowing utilities to use pilot programs to explore novel ways of achieving desired performance outcomes)

Section V:

Potential Performance Outcomes and Associated Metrics

The following list is intended to serve as a menu of potential performance outcomes and metrics discussed by e21 participants that could be considered as part of a multi-year rate plan. The metrics offered below are not intended to eliminate other metrics from consideration, but to provide an initial screening of potential metrics to consider. e21 acknowledges that the metric examples were not fully vetted against the principles and criteria listed above and that this would be a necessary step in the implementation process. Similarly, e21 acknowledges that some of these performance outcomes are closer to being ready for near-term implementation than others. Factors that determine readiness include but are not limited to agreement on these performance outcomes, technological or other capabilities to deliver the outcomes, structural changes, and availability of data for suitable metrics. Further screening and evaluation would be necessary, noting that any and all performance outcomes and metrics would be subject to

determinations of reasonableness and Commission discretion. The outcomes are numbered for ease of reference, but do not represent any ranking preferences.

Outcome 1: Distributed energy resources and grid services are fairly valued and integrated into the electric system in ways that add net benefits and minimize costs.

Explanation: Achieving this outcome means preparing the electric system to cost-effectively accommodate and integrate the adoption of distributed energy resources. Given the significant role that distributed energy resources are expected to play in Minnesota's energy future, it will be important to determine in advance how best to use them effectively as an integrated element of the electric system and compensate them appropriately so that they locate in the most beneficial places on the distribution system. The goal should be to integrate them in ways that add net benefits and minimize costs to the system as a whole. Accurate price signals can encourage distributed energy resources to locate in the best places.

Finally, achieving this outcome will require that interconnection of distributed energy resources is timely, transparent, and fair, and that it meets or exceeds statewide interconnection standards in a cost-effective manner; any necessary structural changes within the Midcontinent Independent System Operator (MISO) to value or otherwise integrate these must also occur. Utilities should take steps to reduce the costs of interconnection, including coordinating the aggregation of distributed energy resources, developing a method to share interconnection costs (e.g., group interconnection studies as is done in MISO), and proposing transparent interconnection rules with detailed study and cost information for providers of distributed energy resources to evaluate.

The metrics below reflect the goals of timely interconnection and locating distributed energy resources on the distribution grid where they provide the most value to the system. This goal does not preclude siting them in other locations, but doing so may result in lower compensation for the provider, commensurate with their value.

- **Examples of Metrics:**
 - a. Interconnection
 - i. Percentage of applications meeting standards defined and established by the Minnesota PUC
 - ii. Median time to connect distributed energy resources (by category)
 - b. Number or percentage of high value installations (e.g., elements of value might include locational, temporal, and ancillary service value)
 - c. Timely and effective provision of locational value information to customers regarding distributed energy resources
 - d. Percentage of customers participating in distributed energy resource programs (e.g., electric vehicles, solar, storage, and demand response)
 - e. Percentage of system needs met by distributed energy resources
- **Notes:** Minnesota statute 216B.1611 authorizes the PUC to develop financial incentives based on a public utility's performance in encouraging residential and small commercial customers to participate in on-site generation. There may be areas of the distribution grid that are more constrained and would benefit from distributed energy resources, but this locational information needs more development as part of utility distribution

planning. Once this information is available, resources that can relieve these constraints should be compensated accordingly.

Outcome 2: Utilities have sufficient incentive to manage controllable costs, particularly operations and maintenance.

- **Explanation:** At a high level, this outcome should be achieved through the overall design of a performance-based multi-year rate plan, such as through a stay-out provision (an agreement to "stay out" of the rate revision process for a given length of time), and tying operating and maintenance increases to an inflation index. More specifically, one area of focus under this goal is to minimize the cost of fuel and purchased energy.
- **Example of Metrics:** Number and duration of unplanned generation outages, which cause the utility to procure replacement energy or capacity.
- **Notes:** The pending AAA docket (AA-12-757) is exploring potential fuel clause cost management.

Outcome 3: The system is made more efficient.

- **Explanation:** This goal seeks to optimize the alignment between generation and load to better utilize the existing system in a cost-effective manner, thus improving resource utilization and potentially avoiding new capital investment that may not be necessary for the long term. This goal also seeks additional efficiencies to be gained at the generation, transmission, and customer levels. e21 participants acknowledge that there are multiple approaches to achieving this goal, including leveraging the existing Conservation Improvement Program and encouraging greater adoption of time-of-use rate options that send more accurate price signals. Metrics could address the high-level goal of optimizing the alignment between generation and load to better utilize the existing system, or address more specific means to achieving the goal. Both types of metrics are listed below.
- **Examples of Metrics:**
 - a. Costs incurred to reduce system peak (dollars per annual (or seasonal) peak reduction (kilowatts))
 - b. Number of kilowatts shifted to off peak
 - c. Percentage of load shifted to off peak
 - d. Number of customers participating in demand response programs
 - e. System load-factor (average / peak)
 - f. Conservation Improvement Program—annual electricity savings (kilowatt hours)
 - g. Conservation Improvement Program—cost per unit of electricity saved
 - h. Conservation Improvement Program—net benefits achieved
 - i. Least amount of BTU (British thermal units) value wasted
 - j. Reduction in line losses
 - k. Percentage of customers participating in time-of-use programs
 - l. Percentage of customers participating in a price signal program, such as Dakota Electric's Stoplight program
 - m. The addition of new time-based rate options

- n. Increased penetration of advanced metering infrastructure or other enabling technologies
 - o. Combined heat and power capacity
- **Notes:** One method to achieving this goal would be increased use of demand response, via a utility-issued request for proposals.

Outcome 4: Reductions are achieved in the pollution and carbon emissions in any part of the energy economy in a cost-effective manner beyond what is required in law.

- **Explanation:** The desired outcome of this goal is a faster reduction in emissions at a larger scale than what would be achieved under state or federal requirements. The intent is not to reward utilities for achieving compliance obligations. As with all of the proposed performance outcomes, the benefits of achieving this will be balanced against cost considerations.
- **Examples of Metrics:**
 - a. Reduction in tons CO₂ and other pollutants
 - b. Reduction in tons CO₂ per megawatt hour
 - c. Progress toward meeting goals for reducing greenhouse gas emissions
 - d. Costs per additional unit of reduction beyond existing requirements
- **Notes:** Some e21 participants believe this goal is already addressed in the integrated resource planning process. The group also recognized that the Clean Power Plan, if it is implemented, may result in metrics or other mechanisms to address this goal. The impact on electric bills of emissions reduction was raised as an important consideration.

Outcome 5: Electricity customers, including low-income customers, have increased access to a wider range of utility and third-party services and products.

- **Explanation:** This outcome relates to customer engagement and the availability of a broader range of customer options. e21 is interested in enabling greater innovation and flexibility for utilities and third-parties to offer new products and services to customers, similar to the current Conservation Improvement Program process. The desired outcome is a broader menu of offerings available to customers, with care taken to being inclusive of low-income customers and ensuring appropriate customer protections. The metrics tie to utility actions that increase offerings and increase convenient customer access to third-party services, products, and new technologies. e21 is also interested in improving existing services offered by utilities.
- **Examples of Metrics:**
 - a. Increased customer awareness of utility offerings
 - b. Implementation of new technologies and services
 - c. Number of available product and service options
 - d. Customer adoption of specific new service or product
 - e. Increased availability of information that facilitates expanded customer offerings
 - f. Customer satisfaction with access to customer and system information from the utility
 - g. Customer satisfaction with the availability of third-party services

- **Notes:** Utilities are currently permitted to propose new offerings, but there could be process improvements at various stages to better achieve this goal, recognizing the need to balance expediency with due process and regulatory resources. On the topic of third-party products, e21 participants also recognize the past docket where the Minnesota PUC made decisions limiting aggregation of retail customers by third parties (docket no. 09-1449).

Outcome 6: Development of efficient, low/no carbon loads (e.g., electric vehicles) is promoted.

- **Explanation:** Energy conservation and other demand-side management programs can reduce utility system costs; however, increased sales allow the system's fixed costs to be spread across a greater number of kilowatt hours, lowering volumetric rates. Therefore, it is appropriate to encourage development of selected new loads. In order to avoid violating other e21 guiding principles, such as carbon reduction, it is important that there are incentives for new load to be efficient and served in a way that meets customer needs while balancing the goal to reduce the carbon intensity of the electric system overall. Examples include the electrification of the transportation system and creation of renewable microgrids to serve new customer loads.
- **Example of a Metric:** Adoption of rates supporting electric vehicles
- **Notes:** The creation of a carbon benefit is dependent on the electricity powering the electric vehicle having a lower carbon intensity than gasoline or diesel. Additional metric development would be needed to identify other metrics within the utility's control.

Outcome 7: High levels of reliability are ensured as driven by customers, as and where needed.

- **Explanation:** Not all customers require, or would want to pay for, greater reliability than they already have; but in an increasingly digital economy more customers do need—and would be willing to pay for—higher levels of reliability. e21 argues that meeting this need is a matter of economic competitiveness. Because e21 also sees maintaining good reliability more generally as important, it recommends that any performance system continue measuring the System Average Interruption Duration Index, the System Average Interruption Frequency Index, and any other established reliability metrics under the PUC's rules. Other metrics may be added as appropriate and possible with newly installed technology.
- **Examples of Metrics:**
 - a. System Average Interruption Duration Index
 - b. System Average Interruption Frequency Index
 - c. Momentary Average Interruption Frequency Index
 - d. Number of validated power quality or voltage complaints to the PUC
 - e. Number and percentage of distribution lines with voltage and volt-ampere reactive controls
- **Notes:** None.

Outcome 8: Customer satisfaction is increased.

- **Explanation:** Customer satisfaction has been and will continue to be a key indicator of a utility's success. As utilities become more customer-centric, it is important to enhance the focus on high customer satisfaction, which could include utility facilitation of third-party offerings.
- **Examples of Metrics:**
 - a. Electricity customer satisfaction indices, or third-party surveys, for residential and business customers
 - b. Transaction surveys
 - i. Percentage of customers satisfied with their recent transaction with the utility
 - ii. Percentage of contacts resolved on the first call
 - c. Number of call-center calls received and the answer speed
 - d. Number of customer complaints received
 - e. Number of service appointments made and fulfilled
 - f. Utility's offering of a variety of ways to obtain outage or emergency information
 - g. Utility's delivery of accurate, relevant, and timely information about outages
 - h. Utility's delivery of convenience and choice for customers' bill-paying
 - i. Percentage of bills that do not need to be rebilled
 - j. Percentage of bills produced by actual meter reads

Notes: Measuring achievement of some of these metrics may require employing independent third-party evaluators.

Outcome 9: Customers are ensured access to basic electricity service that is affordable.

- **Explanation:** Particularly in light of the many expected changes in the electric sector e21 participants wanted to highlight the necessity of customers' access to affordable, basic electricity service.
- **Examples of Metrics:**
 - a. Percentage of eligible customers signed up for affordability programs, such as low-income discounts and payment plans
 - b. Number of avoided disconnections due to customers' enrolling in payment plans
- **Notes:** No additional metrics are proposed for this outcome beyond what regulators already require. However, allowing customers to self-certify low-income eligibility could be considered.

Section VI: Conclusion

A central recommendation of the e21 Initiative's phase I report is the shift to a more performance-based compensation framework, where some portion of utility earnings are linked to utilities' performance on outcomes valued by customers and supportive of state energy policies. It became clear through e21's discussions that there are diverging views about how quickly and how extensively that shift should take place. While this white paper outlines three stages, it does not offer a judgment or recommendation on where the regulatory framework should land along that spectrum. Instead, its aim is to offer principles, guidelines, and potential outcomes and metrics to support Minnesota's incremental movement toward a more performance-based model, irrespective of the final destination.

White Paper: Integrated Systems Planning

Introduction

In phase I of the e21 Initiative, the e21 participants recommended changes to the resource planning process overseen by the Minnesota Public Utilities Commission (PUC), for those utilities that opt into a performance-based multi-year rate structure. Specifically, the e21 participants recommended that, for those utilities that opt to file for a performance-based multi-year rate plan, the resource planning regime should be transitioned to one that focused attention on the five-year action plan of the current resource planning process, streamlining regulatory review of the later years of a resource plan, outside this action plan period. This planning regime was called an integrated resource analysis by the e21 participants in phase I. The concept was to tie the five-year action plan more closely to the rates that would be charged under the multi-year rate plan, creating what e21 referred to as the utility business plan combining utility rates, costs, and investments.

In addition, the phase I participants recommended including more information about transmission and distribution wire and non-wire alternatives in a resource plan, such as additional demand response capabilities and other distributed resource options. This information could help lead to an overall integrated systems plan that considers a number of ways to serve load that includes utility-sited and customer-driven resources across both the transmission and distribution systems.

Thus, in phase II, the group decided to focus on potential modifications to traditional resource planning that would be useful in transitioning it to produce an overall integrated systems plan. This focus recognizes that expanding resource planning to take a broader set of distributed and transmission system alternatives into account will be essential for maintaining a cost-effective, well-functioning electric system, and that describing what that integrated systems planning process might look like would be helpful to all parties—regulators, stakeholders and Minnesota’s electric utilities—not just those utilities contemplating opting into a multi-year rate planning regime as envisioned in e21’s first phase.

In both phase I and phase II, the e21 participants agreed that Minnesota’s resource planning process has served the public interest exceptionally well over the years, providing regulators, customers, and other interested stakeholders insight into the long-range plans of electric utilities, as well as being an opportunity to shape those plans to ensure system reliability and compliance with federal and state policy goals within a least-cost, best-value planning regime. Our proposals to make changes to the resource planning process is not meant to imply that the current planning process is flawed or is being implemented incorrectly. The intent of e21’s current work is only to ensure that this least-cost planning process continues to promote the public interest as the utility industry evolves.

The evolution of Minnesota’s resource planning process is nothing new. Since first being implemented in the early 1990s, the resource planning process has adapted over time as the utility industry has evolved from a set of relatively closed vertically integrated monopolies that essentially self-supplied to include a more complex and competitive wholesale marketplace. Over that time, resource planning evolved with the industry, to include complex modeling, collaborative processes, and other innovations. The discussion below, like the e21 process itself, is intended to explore the next steps in the evolution of the planning process, so that

regulatory processes align with the business environment facing today's utilities and their customers—an environment that includes

- rapid changes in the capabilities and cost-effectiveness of many non-wire alternatives to building traditional utility infrastructure, such as distributed solar, demand response, and energy storage
- increasing concerns about cybersecurity and the interconnectivity of a growing number of assets on the electric grid
- the growing number of active participants in the system, such as “prosumers” (sometimes acting as *consumers*, using electricity from the grid and sometimes acting as *producers*, making their own and selling the excess back to the grid) and third-party service or technology providers

As the electric utility industry evolves, the key question of the current resource planning process will remain, how best to ensure that customers' electricity needs are met over the planning period, in least-cost ways that comply with relevant state and federal requirements? However, instead of primarily comparing utility-scale generation resources needed to meet forecasted customer demand, integrated systems planning must also begin to ask more granular and difficult questions (though not necessarily provide answers and actionable plans at this point in the process). These questions include:

- a. What is the projection for development of demand-side resources, including both customer-driven generation and customer demand response, that are outside of the utility's control?
- b. What additional potential exists for customer- and utility-sited distributed energy resources to cost-effectively meet system needs? Facilitating that potential may require changes to rate design, procurement programs, or other proactive measures.
- c. What might be the opportunities for third parties in the provision or aggregated operation of those resources?
- d. How might supply-side and demand-side resources interact in real time to optimize past and future investments in order to reduce customer cost impacts over the planning period?

Another important consideration for the PUC will be: How can individual utility's integrated systems plans optimally meet Minnesota's needs and public policies, and coordinate with other utilities' plans and the Midcontinent Independent System Operator (MISO) market?

Charge of the Integrated Systems Plan Subgroup

Involving regulatory staff and others typically engaged in the process, the charge to the subgroup was to:

- evaluate how the integrated resource planning process works now
- identify strengths and specific areas for improvement
- summarize proposed changes and additions to the current utility planning processes
- summarize the costs and benefits of making changes to the traditional integrated resource planning process

The e21 integrated systems planning subgroup assessed options for

- a. transitioning resource planning to a more complete end-to-end look at the utility system that can inform planning and alternatives
- b. reducing overall regulatory burden and cost of resource planning, for utility, regulators, and intervenors
- c. tying resource planning more directly to rates charged to customers by examining decisions establishing the costs (both direct and societal) of providing service to utility customers and achieving the agreed-upon performance outcomes
- d. increasing awareness and consideration of potential for distributed generation and non-traditional resource alternatives in the provision of service to utility customers¹¹

In this white paper, we provide a brief overview of the current resource planning process, summarize benefits that the current process provides, and identify critical features of resource planning that must be retained as the process evolves. In addition, this white paper outlines four possible areas for improvement:

- a. optimize the length of time during which a plan is processed through the regulatory system, and better manage the administrative burden placed on regulators, staff, and other parties
- b. expand the scope of the planning process, to take more of an end-to-end systems approach (from the bulk transmission level to the distribution grid)
- c. include more timely information about utility costs and customer impacts from various approaches to the resource mix, infrastructure investments, and delivery mechanisms
- d. improve the balance in the plan review process between reliance on modeling versus a discussion of policy and strategic considerations

At first glance, there may be trade-offs between these topic areas—how is it possible to reduce the administrative burden of resource planning while expanding its scope? However, the hope is that, if we can find ways to ease the administrative burden of the current resource planning process, we may be able to create some head room to incorporate additional complexities into that process without overwhelming available resources.

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¹¹ While we agree that the opportunities for distributed energy resources should be increasingly considered in resource planning (and, in fact, this is required under Minnesota statute § 216B.2426), e21 participants believe that the pursuit and acquisition of any particular resource to meet customer needs is better left to proceedings and programs outside of resource planning.

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** An asterisk indicates they are no longer at their organization and are no longer participants in e21. Also note that participants that have changed organizations since the start of e21's phase II have their new position and organization in parentheses.*

¹² Matt Schuerger was appointed to the Minnesota Public Utilities Commission beginning February 1, 2016, and undertook no further participation in the e21 process.

¹³ Chris Shaw left the Minnesota Department of Commerce in June 2016 to take a position with Xcel Energy and undertook no further participation in the e21 process.

Section I:

Current Resource Planning Process

Brief Overview. Utility resource planning in Minnesota is governed by Minnesota statutes section 216B.2422 and Minnesota rules chapter 7843. Minnesota law defines a resource plan as:

a set of resource options that a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, refurbishing, and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation.¹⁴

The forecast period referred to in that definition is 15 years following the year the plan is filed. The resource plan must identify a five-year action plan, which is defined as:

a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. The action plan must cover a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings.¹⁵

Electric utilities are required to file resource plans with the Minnesota PUC on a schedule determined by the commission, generally every two years. Once filed, the proposed plan is analyzed by expert staff at the Minnesota Department of Commerce. In addition, a number of parties often intervene, engage in formal and informal discovery (the process of gathering information from the utility and other parties to the proceeding), and add their recommendations to the record before the PUC. The resource plans of investor-owned utilities, such as Xcel Energy, Minnesota Power, and Otter Tail Power, are mandatory and subject to PUC approval, whereas plans submitted by municipal and cooperative utilities, while also subject to acceptance or rejection by the PUC, are considered advisory.

¹⁴ Minnesota statute § 216B.2422, subd. 1(d)

¹⁵ Minnesota rules section 7843.0400, subp. 3, item (C)

Current Requirements Related to Resource Planning

- Demand and energy forecast (§ 216B.2422, subd. 2a)
- Existing resources (R. 7843.0400 subp. 3A)
- Conservation goals (§ 216B.241 subd. 1a)
- Environmental costs (externalities) (§ 216B.2422, subd. 3)—PUC is updating this
- Carbon cost (§ 216H.06)
- Future resource options (R. 7843.0400, subp.3A)
- Process and analytical techniques (R. 7843.0400, subp. 3B)
- Sensitivity analysis (R. 7843.0400, subp. 2)
- 50% and 75% renewable scenarios (§ 216B.2422, subd. 2)
- Consideration of distributed generation (§ 216B.2426)
- Likely effects on rates and bills (R. 7843.0400 subp. 4)
- Action plan (R. 7843.0400 subp. 3C)
- Findings of whether or not a utility is in compliance with the Renewable Energy Standard (§ 216B.1691, subd. 3), as well as the Solar Energy Standard (§ 216B.1691, subd. 3) if applicable
- Renewable preference (§ 216B.2422, subd. 4)
- Progress in meeting CO₂ reduction goals (§ 216B.2422, subd. 2c)
- Description of efforts to obtain community-based energy development projects (§ 216B.1612, subd. 5b)¹
- Renewable Energy Standard cost impact (§ 216B.1691, subd. 2e)
- Compliance with previous PUC orders—things the PUC has asked be addressed in the next integrated resource plan filing
- Resource plan rate impact
- Socioeconomic studies for existing facilities/retirements
- Cost/benefit analysis for demand-side management

Strengths of the Current Process. e21 participants identified a number of strengths of the current planning process, aspects that should be built on and not lost as planning evolves to address increasing customer and community expectations and other opportunities facing the electric industry. Chief among those strengths is that resource planning helps ensure reliable service over the long term, and it provides regulators, customers, and stakeholders critical insight into the decisions that the utility needs to make to cost-effectively ensure reliability while meeting other public policy goals, both in the short term and with regard to “over the horizon” issues. The current process provides iterative planning opportunities prior to resource commitments, allowing regulators, utilities and other participants to assess, via a resource plan docket, the importance of multiple variables and sensitivities, including cost, size, type, timing of alternatives, and demand forecasts, before committing ratepayer funds to acquire electricity resources. Minnesota’s resource planning process creates relatively unrestricted opportunities for intervenors to explore the utility’s system, proposed plan, and alternatives, to take a broad look at where the system is today, and current goals and future plans to meet customer needs. The process is robust—since utility plans are refreshed every couple of years, this allows course corrections to respond to changes in the utility landscape.

Section II:

Four Areas for Potential Improvement

This section describes the four main areas for potential improvement identified by e21, summarizes participants' discussion of each area, and evaluates potential modifications that could be made to the current resource planning process.

Area 1: Optimize the length of time during which a plan is processed through the regulatory system, and better manage the administrative burden placed on regulators, staff, and other parties

Discussion. Early in the discussion, a number of e21 participants identified the length of time it sometimes takes to process a resource plan to be a challenge—key drivers can change between plan filing and plan approval that create a need to reset the plan, thereby extending the process. As can be seen from the following table, the length of time to process a resource plan can range from 6 to 43 months. Some resource plans can take longer to process, depending on the complexity of the issues raised in the resource plan or the sufficiency of the information provided by the utility. The three longest resource plans—Otter Tail Power's 2005 plan, Great River Energy's 2008 plan, and Xcel Energy's 2010 plan—all had significant issues that required much more time to process than the vast majority of plans.

The average length of time from the date of filing a resource plan to PUC action is 16 months, and only 14 months if the three longest plans are removed from the calculation (see Table 1). Given the complexity of the issues that are considered in a resource plan and the increasing number of filings that state utility regulators and staff need to process, 14 months to process a major filing like a resource plan does not seem unreasonable, especially given the increasing number of utility rate cases and other complex filings that demand the PUC's attention.

Table 1. Length of Time from Filing of Resource Plans to PUC Action

Docket No.	Utility	Date Filed	Date of Minnesota PUC Decision	Length of Proceeding (in Months)
05-184	Dairyland Cooperative	Jan 2005	March 2006	14
05-968	Otter Tail Power	June 2005	Jan 2009	43
05-1100	Great River Energy	June 2005	July 2006	13
05-1102	Missouri River Energy Services	July 2005	Oct 2006	15
05-2029	Interstate Power	Jan 2006	March 2007	14
06-977	Minnkota Electric	June 2006	Oct 2007	16
06-605	Southern Minnesota Municipal Power Agency	July 2006	Dec 2007	17
07-1357	Minnesota Power	Oct 2007	Sept 2008	11

07-1572	Xcel Energy	Dec 2007	July 2009	18
08-784	Great River Energy	June 2008	Nov 2010	29
08-846	Basin Electric	June 2008	Dec 2009	18
09-1088	Minnesota Power	Oct 2009	April 2011	18
10-623	Otter Tail Power	June 2010	Dec 2011	18
10-782	Minnkota Electric	June 2010	May 2011	9
10-735	Minnesota Renewable Energy Society	July 2010	Jan 2012	17
10-825	Xcel Energy	Aug 2010	Feb 2013	30
08-673	Interstate Power	Nov 2010	Jan 2012	14
11-918	Dairyland Cooperative	Sept 2011	Sept 2012	12
12-1114	Great River Energy	Nov 2012	July 2013	8
13-53	Minnesota Power	March 2013	Sept 2013	6
13-1104	Southern Minnesota Municipal Power Agency	Nov 2013	Jan 2015	14
13-961	Otter Tail Power	Dec 2013	Oct 2014	10
13-1165	Minnesota Municipal Power Agency	Dec 2013	Jan 2015	13
14-77	Interstate Power	March 2014	July 2015	16
14-526	Minnkota Electric	June 2014	May 2015	10
14-813	Great River Energy	Nov 2014	Sept 2015	10
			Average	16

Still, reducing the length of time needed for processing a resource plan would seem to be a useful goal if this could be done while building on the strengths of the current planning process described above. Additionally, easing the administrative burden of processing a resource plan will be especially important as the complexities of resource planning evolve to become a more integrated system evaluation that includes more technologies and more information about demand-side, customer-driven opportunities. In addition, from the perspective of intervenors in PUC proceedings, some additional streamlining is seen as necessary, as resource plans, rate cases, and other utility dockets become increasingly more complex and strain available regulatory, utility, and intervenor resources.

Given that the current resource plan provides a platform for identifying resources and/or capabilities that will be needed to serve customer needs over the planning period, the integrated systems plan should build on that to provide—and receive—input and information to and from other important utility proceedings such as transmission plans, distribution system plans, and rate cases. The current planning process does include this kind of information to some extent, and this interactivity between proceedings is not new, but a future planning process may require regulatory processes to be more dynamic and interactive.

e21 participants identified the resource planning process as often too adversarial and believed that the quasi-judicial nature of the process can be cumbersome, adding to the length of time needed to process the plan. Generally speaking, participants shared a view that the process should be more of a conversation than a battle of competing philosophies, to the extent possible and productive. In this way, regulators, utilities, and intervenors can explore alternatives and sensitivities together, clarifying and isolating the important options or decisions that must be decided by the PUC, informed by the technical work by the utility and regulatory staff.

Some e21 participants suggest that one contributing factor to this adversarial dynamic is that well-intentioned parties sometimes try too hard to perfect the utility's resource plan, particularly in the later years of the plan, which gives rise to battles over modeling assumptions, long-term scenarios, and sensitivities. Forecasts and data later in the planning period (beyond the initial five- to seven-year period that constitutes the action plan) are difficult to validate. Reaching for precision with regard to the planning data in these later years can increase tension between and among the utility and intervenors and add to the length and difficulty of a planning proceeding.¹⁶ Moreover, technology is evolving and opening new options so quickly that perfecting the utility's resource plan is even more challenging, particularly for its later years.

Another contributing factor to this sometimes adversarial dynamic is that the resource planning process seems to have competing goals—is it intended to be a high-level overall snapshot, or should we be making detailed analyses on issues such as generation retirements? e21 participants were not able to resolve this question, most likely because too much depends on the context for each particular resource plan—there are plans without significant controversies and these can often be processed more quickly.

Finally, e21 participants discussed the general lack of consistency from plan to plan and from utility to utility. We discussed issues such as a lack of a common vocabulary or standard naming conventions across plans—what's a base case, what's a reference case, what's a preferred plan—as well as changing assumptions and methodologies.

Potential Modifications. The e21 participants discussed a number of potential modifications to the processing of utilities' resource plans. Many of these possible modifications did not receive broad support among the group, such as establishing statutory timelines for resource plan approval, imposing a higher regulatory standard for utility requests for plan extensions, and statutorily restricting intervenor discovery beyond the five-year action plans. However, a number of other potential modifications seemed worthy of further discussions.

One set of concepts that e21 participants thought might be fruitful to explore involves increased collaboration between the utility, regulators, intervenors, customers, and the communities served by the utility. Most of Minnesota's utilities are working to increase stakeholder outreach as part of their resource planning, and one such collaboration seems to have contributed to the success of Minnesota Power's 2013 resource plan. Prior to filing the plan, the utility met with regulatory staff from the Minnesota Department of Commerce to validate the load forecast the utility planned to use in its resource plan, thereby taking this foundational plan input off the table to be fought over during the regulatory process.

¹⁶ However, utilities require long-term planning horizons to ensure they meet reliability requirements and to allow sufficient time to plan for major fleet transitions. Resource plans today must rely on proven technologies and their established value within the North American Electric Reliability Corporation and in the regional market in which the utility operates.

Other important inputs to a resource plan can potentially be worked out between the utility, regulatory staff, and likely intervenors prior to filing, such as key assumptions, modeling inputs and sensitivities, and planning scenarios. This could be done either sequentially with these stakeholders or in a collaborative process, much like a “pre-trial conference” where significant issues would be resolved prior to the utility writing and filing its plan. A similar concept was included in the following e21 phase I recommendation:

To ensure appropriate stakeholder and regulatory evaluation of the [utility resource plan], a utility that opts in to this framework would be required to engage a broad group of stakeholders up front, prior to filing the [plan], so that all interested parties have the opportunity to inform and shape the analysis.¹⁷

This pre-filing process involving the utility, regulatory staff, and other stakeholders could be facilitated either by a lead commissioner (see box below) if the PUC opted to designate one for that particular resource planning docket, by staff from the PUC or Department of Commerce Division of Energy Resources if workload permitted, or by a third party with regulatory expertise.

Minnesota statutes, section 216A.03, subdivision 9, authorizes the Minnesota PUC to designate one of its five members to be the lead commissioner for “a docket, a type of docket, or for a particular subject area.” That subdivision continues:

The commission shall allow interested persons to be heard on a proposed designation prior to making the designation. The lead commissioner is authorized to exercise the commission’s authority to develop an evidentiary record for a proceeding, including holding hearings and requesting written or oral comments. At the request of the commission, the lead commissioner shall provide the commission and the service list for the proceeding with a written summary of the evidentiary record developed by the lead commissioner for the case, including any recommendations of the commissioner. Any findings of fact, conclusions of law, or recommendations of the lead commissioner are advisory only and are not binding on the commission. The commission may delegate its authority to designate lead commissioners to the chair. Nothing in this subdivision affects a person’s opportunity to request a contested case proceeding under chapter 14.

e21 participants raised concerns that the adversarial nature of the current process can sometimes seem to pit stakeholders against one another’s interests, for example, customer interests versus environmental interests versus utility shareholders. As one participant said, “customer advocates are not lobbying for increased carbon, and environmentalists are not lobbying for increased rates.” It is important to be able to find and recognize common ground when possible, ensuring that precious time before the PUC is reserved for making decisions about the most important issues raised in the planning process.

Another participant suggested that resource planning is more complicated than it needs to be. The pre-filing process could help identify and highlight the few variables and scenarios that have significant impact on planning options, then let those impacts inform the decisions the PUC makes about the utility’s resource needs. If the evaluation were to be kept at this higher level, it is possible that resource plans would not be as adversarial or contentious.

¹⁷ *e21 Initiative Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota* (Minneapolis, MN: Great Plains Institute (2014), 14.

Other possible modifications to the resource planning process that might address concerns raised by e21 participants included

- a. the development of standardized naming conventions for what constitutes a “base case,” a “reference case,” or a “preferred plan,” and other terms commonly used in resource plans
- b. the identification of best practices used by utilities in Minnesota from plan to plan, to be shared on a regular basis
- c. the standardization of modeling techniques to be used by Minnesota utilities and intervenors, such as how energy efficiency and distributed generation should be modeled

These concepts could be developed and shared via an annual or biennial resource planning workshop. Minnesota PUC staff convened such a workshop early in 2015 to discuss with utility resource planners how best to address the question of which peak demand Minnesota utilities should be planning to meet for resource adequacy purposes, their own or that of MISO.

In addition to these ideas, e21 participants discussed how a more integrated, synchronized process of resource planning and rate cases would be helpful—with resource planning informing and helping set budgets for the rate case. Coordinating the two could increase efficiency by allowing for reliance on common models, data, and other information to inform both processes. This concept was embedded in e21’s phase I recommendations for a five-year comprehensive utility business plan, including the goal of reducing the frequency of resource planning from its current two-year cycle to five years, which would reduce the overall regulatory burden.

Some participants felt that perhaps an incremental step toward this business plan concept would be to allow the PUC to set the schedule for utility rate cases like it does utility resource plans, or otherwise coordinate the two filings for those utilities that opt to file multi-year rate plans. Doing so would likely require legislative action, but could allow these dockets to be synced and could potentially reduce the overall burden on regulators, staff, and intervenors. On the other hand, synchronizing two massively complex proceedings such as a rate case and a resource plan would need to be done carefully and with significant awareness of possible pitfalls so as to not overwhelm the regulatory capacity to review both cases that the public interest requires. Additionally, utilities that are not contemplating opting into a multi-year rate plan regime would oppose giving up their current ability to decide when their revenue conditions warrant the filing of a new rate case.

Another thought along these lines would be to pick a date—for example, 2020—to develop the full scope of the utility business plan concept and establish the regulatory structure for those utilities that might opt in to such a regime.¹⁸

¹⁸ e21 participants recognize that there are practical issues associated with such a proposal for both utilities and regulators that will require careful thought and planning to prevent unintended consequences.

Area 2: Expand the scope of the planning process to take more of an end-to-end systems approach (from the bulk transmission level to the distribution grid)

Discussion. As we've discussed, the resource plan is already a major proceeding, involving a great deal of time and energy for utilities, intervenors, and regulatory staff. Resource plans generally take more than a year to complete and are occasionally updated by utilities while they are still pending, which lengthens the proceedings. In addition, the resource plan does not actually select new resources for the utility; therefore, once it is approved or modified there are typically additional proceedings to fully implement the action plan. These, too, can prove to be lengthy and they sometimes revisit ground that the resource plan already has covered.

e21 participants recognize that a key consideration in expanding resource planning to become more of a systems approach is that, currently, distributed and demand-side resources (such as distributed generation, demand response, energy efficiency, and customer-driven storage) may not be adequately considered in the process. Demand response is treated in the plan modeling as a reduction to capacity needs based primarily on the number of customers enrolled in utility programs in the recent past and some assessment of the resource potential.

Similarly, energy efficiency is generally treated in the modeling as a reduction to the energy and demand forecast, based primarily on expectations of achievable potential relative to the utility's avoided costs.¹⁹ The possibility of a growth in customer-owned generation is not explicitly considered in the model; instead, it is implicitly included at the historical rate in the demand forecast. As a result, the cost of these distributed resources is generally not compared with other supply options to optimize the combination of supply- and demand-side resources in an apples-to-apples, resource-to-resource kind of way. By omitting this type of analysis, important and cost-saving opportunities to proactively develop non-traditional solutions to meeting expected demand for electricity and other grid services may be overlooked (e.g., altering rates or rate design to encourage demand management or more optimal siting of customer-owned resources).

The increasing cost-effectiveness of distributed energy resource alternatives available to the customer will likely make this evaluation important in the future. Resource planning currently does not incorporate the elasticity of customer demand and will need to. This evaluation should be qualitative to start with, until Minnesota has more experience with distributed energy resources, but the analysis will need to become more quantitative as the magnitude of distributed energy resource adoption increases. The e21 participants note that this is not an evaluation of choices the utility might make in a resource-acquisition proceeding; rather, it is an assessment of choices that customers may make on their own to serve their own electricity needs, which could impact the size, type, and timing of resources evaluated in a utility's planning process.

Strategist, the capacity expansion model used by most utilities in Minnesota and the Minnesota Department of Commerce, has the capability of allowing a demand response resource to be an option in addition to generation options. As a general rule, though, demand-side resources such as energy efficiency and demand response are currently reflected in utility demand forecasts as reductions in demand (measured in megawatts) and electricity (measured in megawatt hours) which are used to define the needs utilities must meet. There are limited modeling runs allowing the model to select demand-side resources along with supply-side resources.

¹⁹ The calculation for utility avoided cost is based primarily on avoidance of the need to add the next generating unit on the utility's system, usually a combustion turbine.

With regard to energy storage, the method or methods for modeling and evaluating these opportunities in a resource plan have not yet been developed in Minnesota, given the state's limited adoption of storage technologies to date. However, utilities, regulators and others in the state have long been evaluating various storage technologies and their potential to address utility system and customer needs. Activity on energy storage in Minnesota has increased significantly in recent years, evidenced by the recent formation of the Minnesota Energy Storage Alliance, deployment of Great River Energy's community energy storage program, and other utility, regulator, and stakeholder efforts.

e21 participants also discussed concerns that extending the resource planning process to include more information about transmission- and distribution-level planning could bog down the planning process, exacerbating concerns about the length and complexity of resource planning dockets. As a general rule, e21 participants agreed that while distribution planning is essential, expanding the resource plan to become a system plan is not the same as incorporating a detailed distribution plan in with the resource plan, and they do not recommend incorporating detailed distribution planning into resource planning.

The system plan could be envisioned more as a look at all of the electricity needs in the utility service area and how those needs will be addressed—whether through utility-owned and contracted supply, demand-side management, or customer-managed generation. Just as the current resource planning process informs a subsequent detailed resource-acquisition process, a system-planning process would be a platform from which information is developed to advise other, more detailed distribution and transmission planning processes. Incorporating consideration of *all* load and *all* forms of serving it would bring a system focus to the plan.

To a large extent, this is consistent with how Minnesota utilities approach resource planning currently. For example, Xcel Energy reports that it does address all known load and power supply options, either by reflecting these in its demand/energy forecast or as a resource option (generation options, demand response, incremental demand-side management, small solar installations, and potential storage technologies). However, it may be useful, as Minnesota's experience with customer adoption of distributed resources grows, for utilities to consider developing comprehensive long-range forecasts of customer adoption of distributed energy resources. A forecast of this type could help identify the net load the utility will need to serve, as well as provide potentially useful information about its customers and how the distribution system could evolve to meet customer needs. The Sacramento Municipal Utilities District is reported to have recently completed such a forecast.²⁰

Potential modifications. In the same way that the resource plan becomes a template for eventual resource acquisition, the integrated systems plan could inform more detailed distribution planning and grid improvement processes (and vice versa), and consideration of a wider range of options (including non-traditional solutions) for meeting any particular system need.

²⁰ See Erika Myers and Obadiah Bartholomy, "Leveraging Customer-side DERs to Benefit All Utility Customers," *Smart Electric Power Alliance* (blog), June 2, 2016, <https://www.solarelectricpower.org/utility-solar-blog/2016/june/leveraging-customer-side-ders-to-benefit-all-utility-customers.aspx>.

Among other things, an integrated systems plan should cover

- a. the utility's demand forecast with and without adjustments for additional load-reducing opportunities
- b. an inventory and forecast of aggregated customer-owned generation and other customer-controlled resources
- c. an inventory and forecast of distributed energy resources, including both utility- and customer-controlled resources. Customer-driven resources are not yet sufficient in scale and magnitude to be of significance in the big picture of utility resource planning
- d. an inventory of utility-owned generation and forecasted retirements
- e. an inventory of contracted supply
- f. a general description of known/planned transmission and distribution-system upgrades and how these are considered within the development of the proposed resource plan
- g. an assessment of potential energy storage applications and the technology performance and economics benchmarks used for this assessment

To accomplish the above, e21 sees value in exploring the use of other models to supplement the existing Strategist model since Strategist may not be well suited for the detailed evaluation of distributed resource options, or of the interactivity of load and supply at a more granular timescale (although it is very useful in other aspects of the planning process). This could be done by an independent third party with experience and expertise in resource modeling, like the Electric Power Research Institute or the Regulatory Assistance Project, which could be asked to provide an evaluation of potential modeling platforms that could be used to supplement Strategist.

The pre-filing process described in the previous section, where the utility, regulators, and stakeholders convene to discuss assumptions prior to filing a resource plan, could be an opportunity to find consensus assumptions for a wide variety of aspects of system planning including the family of assumptions that will be used in the modeling.²¹ The pre-filing process allows parties to focus their comments on the outcomes of the planning work, avoiding discovery of and fights over the assumptions and other inputs that went into the modeling. Explicit responsibilities added to this pre-filing process could include determining how to forecast the potential for customer-driven supply- and demand-side resources in a planning period, and how to evaluate these resources against traditional supply resources available to the utility.

The idea of getting the utility, its regulators, and likely intervenors together to discuss and agree to assumptions, scenarios, and sensitivities that will be used in the utility's resource plan is similar to the process used by the Northwest Power and Conservation Council, as described to the e21 participants by Jim Lazar of the Regulatory Assistance Project. Lazar described how the council forms a number of advisory, collaborative task forces of experts to develop and make recommendations to be used by the council in its resource planning process for the Pacific

²¹ This list of assumptions could include load forecast, resource option costs/performance, natural gas forecast, market capacity and energy price forecast, coal price forecast, wind and solar forecast, sensitivities, demand-side resource cost and performance, and the number and description of scenarios that will be run.

Northwest. Stakeholders in these proceedings collaborate on assumptions, scenarios, and sensitivities regarding

- load forecast
- generating resources
- conservation resources
- demand response
- direct use of natural gas
- quantifiable environmental costs

This process is highly collaborative and successful, and leads to significant consensus on many plan components, isolating key differences that can be resolved only by the council.

e21 also discussed the possibility that certain resource planning requirements that were necessary in the past may now be redundant or unnecessary. Two, in particular, that participants discussed were:

- a. the requirement in Minnesota statute section 216B.2422, subdivision 2 that a utility include a scenario in its resource plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources
- b. the requirement in Minnesota statute section 216B.1612 that a utility include in its resource plan a description of its efforts to purchase electricity from community-based energy development projects, including a list of the projects under contract and the amount of community-based energy purchased

Since the 50%/75% scenario requirement was enacted, the state has established many other ways to encourage or require the deployment of renewable energy and energy efficiency, which some e21 participants agreed rendered this requirement arguably unnecessary. Others disagreed, finding that the planning requirement was a useful tool for resource planning. With regard to the community-based energy development requirement, intensive efforts to establish these projects have resulted in only a modest number of operating projects, and over the past few years, efforts have shifted to other methods to promote community involvement in energy development. The Minnesota legislature repealed the requirement for community-based energy development in the 2016 legislative session, while this white paper was being prepared.

While the elimination of either or both of the above requirements will likely not shorten plan preparation or processing significantly, they are an example of possibly superfluous requirements that unnecessarily add to the scope and complexity of a resource-plan proceeding. Identifying and evaluating requirements like these could be made a part of the annual or biennial resource planning conference discussed above.

Addressing how a utility's resource decisions might affect compliance with the newly issued but recently stayed federal Clean Power Plan rule should also be incorporated into the resource planning process (or future regulation depending on what happens with the Clean Power Plan). Doing so would likely require an evaluation of numerous compliance options, including location and timing decisions to maximize the compliance value of a given action. In this period where the Clean Power Plan rule has been stayed by the U.S. Supreme Court, the focus of this evaluation could be placed on identifying "few or no regrets" strategies for sensible resource

options that could ease compliance should the Clean Power Plan or some future greenhouse gas regulation be implemented.

Area 3: Include more timely information about utility costs and customer impacts from various approaches to the resource mix, infrastructure investments, and delivery mechanisms

Discussion. e21 participants discussed the concern that there is insufficient analysis devoted to understanding the relationship between the costs of various resource plan options and their potential customer impacts. Strategist modeling may show only a small difference between the revenue requirements of different scenarios on a system-wide basis (expressed in calculations of their present value). But a heavy reliance on comparing the present value of alternatives can mask or downplay important potential rate impacts of different resource plan options on customers. It is important to e21 participants that these customer rate impacts be more clearly highlighted and evaluated.

Potential modifications. The e21 group discussed the possibility of regulators and stakeholders working with the utility, perhaps in the pre-filing process discussed above, to identify a small number of scenarios and key sensitivities for the utility to evaluate. As part of that evaluation, the utility would conduct a five-year rate impact analysis of up to five alternative plan scenarios, in addition to the overall rate impact of the preferred plan and the comparisons among revenue requirements of various sensitivities that are currently provided (again, expressed in present value terms).

Strategist can provide information that can be used to develop annual revenue requirements of these planning scenarios, such as the magnitude and timing of annual incremental costs of a given scenario over the planning period. Scenario rate impacts would be made a part of the overall evaluation of scenarios presented to the PUC and would help inform its policy decisions on the utility's resource plan. In the group's discussions, e21 participants commented that the Minnesota PUC may not be interested in picking a single plan, but rather on weighing factors among several possible plans and adopting a course of action that takes the best of what has been presented and compiles those as the approved integrated systems plan for the utility.

Further, participants believe that the Commission should consider, in addition to these scenario and plan rate analyses, an evaluation of innovative options that potentially increase system efficiencies or defer investments and therefore potentially reduce overall costs—such as value-of-solar pricing, time-of-use electricity rates, dynamic pricing, system efficiencies that could be captured by grid modernization, and improved utilization of existing generation through demand response.

Area 4: Improve the balance in the plan review process between reliance on modeling versus a discussion of policy and strategic considerations

Discussion. As can be seen from the foregoing discussion, the e21 group spent a good deal of time discussing the impact of a heavy reliance on the Strategist model on resource planning overall. Strategist has provided significant value to utilities, regulators, and intervenors, allowing parties to more easily make the economic case for their positions or decisions. However, while system modeling is highly informative and allows the comparison of alternative resource options with relative ease, over-reliance on modeling can lead to contention and add to the length of a proceeding without informative discussions by parties regarding important considerations, such as comparing potential customer impacts, utility costs, policy outcomes, and MISO market

interactions (sales and purchases) between the proposed plan and various alternative scenarios.

Because modeling can be too often seen as providing “the answer” in a resource plan, parties engaged in the planning docket can spend a lot of time and resources fighting over the proper inputs, leaving less time to focus on significant issues of policy and strategy and recognition of market and regulatory environment considerations that cannot be addressed with modeling. A sampling of comments made by e21 participants can provide a sense of their concerns:

- a. There may be too great a focus on modeling and data and insufficient consideration of judgment and experience—much of resource planning is policy-based and needs to reflect interaction with the MISO market and key aspects of the known and projected planning environment.
- b. Calculations of the present value of revenue requirements associated with different resource plans results in a number that implies precision where it does not exist.
- c. The options available to meet customer needs are increasingly complex, and the changes that are happening are ones that increase the speed of system interactions. As we get to higher penetrations of variable renewable resources, all parties will be participating in a system that changes moment to moment—it will be difficult for long-range models like Strategist to deal with this.
- d. The fact that most stakeholders lack Strategist modeling capability can be a significant disadvantage when participating in a resource-plan process.
- e. In recent years, there has been an increased emphasis on modeling over policy. System modeling is informative but doesn’t always address the broader issues in meeting state and federal policy goals or customer needs and expectations.
- f. Generic resources and options considered in modeling can be very different from the actual resources that are offered in a resource acquisition process.

Potential modifications. e21 participants discussed the potential for increased stakeholder collaboration, perhaps including the pre-filing process identified earlier, to address these concerns with Strategist. As with the discussion of customer impacts, e21 suggests identifying a small number of scenarios and key sensitivities that “matter”—those that impact the evaluation of resource plan options in significant ways—then evaluating each for their rate impacts on customers, system reliability impacts, impacts on the environment, the ability of the utility to comply with evolving state and federal goals and increasing customer expectations, and doing so in collaboration with regulators and stakeholders. This process improvement would help to maximize the benefits of modeling while minimizing the difficulties of over-reliance on modeling.

Section III:

Potential Modifications to Resource Planning

While e21 did not attempt to reach consensus on recommendations, participants did agree that there were a number of potential modifications that would achieve the goals the subgroup set for this work:

- a. transitioning resource planning to a more complete end-to-end look at the utility system that can inform planning and alternatives
- b. reducing overall regulatory burden and the cost of resource planning, for utilities, regulators, and intervenors
- c. tying resource planning more directly to rates charged to customers by examining decisions establishing the costs (both direct and societal) of providing service to utility customers and achieving the agreed-upon performance outcomes and
- d. increasing awareness and consideration of the potential for distributed generation and non-traditional resource alternatives in the provision of service to utility customers.

We believe each of these potential modifications deserve further study and consideration by the Minnesota PUC and the greater resource-planning community. These potential modifications are summarized in Table 2.

Table 2: Potential Modifications to Resource Planning

Number	Potential Modification	Description	Notes	Impact	Page
1	Facilitate pre-filing collaboration	Hold a pre-filing collaboration to create understanding and potential agreement among parties around modeling assumptions, resource costs, planning scenarios, and sensitivities	Could be led by a lead commissioner, regulatory staff, or the utility preparing the plan	Reduces post-filing disputes over these issues that can increase time needed for plan evaluation, comments, reply comments, and preparation for PUC hearing on plan	55-56, 60

Number	Potential Modification	Description	Notes	Impact	Page
2	Standardize naming conventions	Develop standardized naming conventions for what constitutes a “base case,” a “reference case,” a “preferred plan,” and other terms commonly used in plans	Should be included as a topic in an annual/biennial systems planning workshop (see potential modification #5)	Is part of continuing process improvement of Minnesota resource planning and improves quality, consistency, clarity, and ease of understanding across utility resource plans	57
3	Identify best practices	Identify best practices used by utilities in Minnesota from plan to plan, to be shared on a regular basis	Should be included as a topic in an annual/biennial systems planning workshop (see potential modification #5)	Is part of continuing process improvement of Minnesota resource planning and improves quality, consistency, clarity, and ease of understanding across utility resource plans	57
4	Standardize modeling techniques	Standardize modeling techniques to be used by Minnesota utilities and intervenors, such as how variable and distributed resources, demand response, and energy efficiency resources should be modeled	Should be included as a topic in an annual/biennial systems planning workshop (see potential modification #5)	Is part of continuing process improvement of Minnesota resource planning and improves quality, consistency, clarity, and ease of understanding across utility resource plans	57

Number	Potential Modification	Description	Notes	Impact	Page
5	Hold annual or biennial systems planning workshops	Hold annual or biennial systems planning workshops to discuss planning, modeling, and forecasting issues and share best practices, as well as to consider new policies and planning requirements and MISO market impacts	Led by regulatory staff with the assistance and participation of resource planners and intervenors, or by the utility resource planners themselves	Is part of continuing process improvement of Minnesota resource planning and improves quality, consistency, clarity, and ease of understanding across utility resource plans	57
6	Minnesota PUC to coordinate rate cases and resource plans	Allow the Minnesota PUC to set the schedule for utility rate cases and resource plans, or otherwise coordinate the two, as a precursor to a utility business plan for those utilities that opt to file a multi-year rate plan	Would likely take legislative action to authorize	Allows for better alignment between multi-year rate plans and resource plans	57
7	Put utility business plans in place by 2020	Develop the full scope of the utility business plan concept and establish the regulatory structure for those utilities that might opt in to such a regime	Would likely be done by another group of e21 participants	Allows for implementation of e21 phase I recommendation	57
8	Evaluate supplemental modeling platforms	Explore alternative planning modeling platforms that could provide better near-term integration of demand-side resources and customer-owned generation with supply-side resources	Could be done by an independent third party with experience and expertise in resource modeling (Regulatory Assistance Project, the Electric Power Research Institute, etc.)	Is part of a continuing process improvement policy for Minnesota resource planning	60

Number	Potential Modification	Description	Notes	Impact	Page
9	Include more information about demand-side resources and capabilities	Include more information about the opportunities around demand-side resources and capabilities on a utility system, including better forecasting of those resources over the planning period and potential interactivity with utility resources	Additional information needed as the distributed resource becomes significant enough to affect planning Distributed energy resource forecasts, however, could provide useful information about customer preferences	Allows for better understanding of the resources customers will acquire on their own, to better understand resources the utility will need to acquire	58-60
10	Evaluate the repeal of outdated planning requirements	Evaluate, for example, the continued usefulness of the requirement for 50/75% renewable capacity scenario	Could be included as a topic in an annual/biennial systems planning workshop (see potential modification #5)	Is part of a continuing process improvement policy for Minnesota's resource planning	61
11	Ensure compliance with Clean Power Plan (or future greenhouse gas regulation)	Address how a utility's resource decisions might affect compliance with the Clean Power Plan (if it is implemented) or future greenhouse gas regulation	To be provided by the utility preparing a resource plan	Ensures that Minnesota is well prepared for any future greenhouse gas regulation	61-62
12	Do five-year rate impact of key scenarios	Include a five-year rate impact analysis of up to five key scenarios identified in pre-filing collaboration, in addition to the preferred plan overall rate impact and present value revenue requirements comparisons currently provided	To be provided by the utility preparing a resource plan	Informs resource planning choices and decisions	62

Number	Potential Modification	Description	Notes	Impact	Page
13	Evaluate innovative options to increase system efficiencies	Provide an evaluation of innovative options that increase system efficiencies, defer investments, smooth rate impacts over time, and therefore reduce overall costs, such as value-of-solar pricing, time-of-use rates, dynamic pricing, and system efficiencies that could be captured by grid modernization	To be provided by the utility preparing a resource plan	Expands the scope of options that could be deployed to serve load, potentially decreasing costs	62

Section IV: Conclusion

The resource planning process has served Minnesota very well since its implementation in 1991. For the most part, the process has ensured the availability of cost-effective, reliable, and environmentally compliant resources for customers; helped avoid the construction of unneeded and higher-cost resources; met state electricity requirements; and either met or is making good progress toward meeting Minnesota's energy policy goals. Through the years, the process has evolved to address changes in the industry such as the introduction of wholesale competition, the use of environmental costs, the emergence of renewable energy standards, and introduction of the MISO regional electricity market. As the industry continues to evolve, additional adjustments to the process will likely be needed.

The considerations discussed in this white paper are directed toward creating additional collaboration around utility resource plans that could help streamline Minnesota's resource planning process, while at the same time incorporating emerging resource options and new issues facing utilities as they plan for the future. Recognizing these new trends and transitioning to Integrated Systems Planning will help improve utility plans and continue the tradition of open and forward-thinking planning in Minnesota driven by continuing efforts to ensure a safe, reliable, affordable, and environmentally sound electricity supply to meet all utility customers' needs.

White Paper: Grid Modernization

Introduction

The basic design of the electric grid has remained largely the same since the first commercial power plant in the U.S. went into service in 1882. Electricity has been mostly generated remotely at large central stations, transmitted long distances with high-voltage transmission lines, and then reduced in voltage for local distribution and delivery to customers.

Today, one might think of the shift we are experiencing in the electricity sector as being similar to the shift from large, centralized mainframe computers that once filled entire rooms to the highly distributed system of laptops and smart phones that have now put computers quite literally in nearly everyone's hands. With the emergence of distributed energy resources (DERs) of many kinds, the electricity sector is going through much the same decentralizing transformation.²² This trend toward a more distributed electric system is not to the exclusion of central power plants but in addition. Indeed, the vertically integrated electric system has been evolving for years to be cleaner and more efficient, and has integrated more renewable resources in a cost-effective manner. To effectively manage this paradigm shift toward a more decentralized system will require a modernized electric grid. According to the U.S. Department of Energy's *Quadrennial Energy Review*,²³

A revolution in information and communication technology is changing the nature of the power system. The smart grid²⁴ is designed to monitor, protect, and automatically optimize the operation of its interconnected elements, including central and distributed generation; transmission and distribution systems; commercial and industrial users; buildings; energy storage; electric vehicles; and thermostats, appliances, and consumer devices.

In other words, we are headed for a more networked grid that is able to respond and adapt to rapidly changing technologies being deployed by customers at the so-called grid edge and that can function in new and untraditional ways.

The Minnesota Public Utilities Commission's (PUC's) working definition of a modern grid was put forth in a March 2016 staff report on grid modernization.²⁵

²² Distributed energy resources are supply- and demand-side sources of electricity that can be used throughout an electric distribution system (i.e., on either the customer side of the customer's meter or the utility side) to meet electricity and reliability needs of customers. Distributed energy resources include end-use efficiency, distributed generation (solar photovoltaics, combined heat and power, small wind), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (communications and control technologies).

²³ *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure* (U.S. Department of Energy, 2015).

²⁴ Smart grid technologies include: distribution system management systems, energy efficiency, combined heat and power, fuel cells, gas turbines, rooftop solar photovoltaics, distributed wind, plug-in hybrid and all-electric vehicles, distributed storage, demand response, and so-called transactive building controls.

²⁵ *Minnesota Public Utilities Commission Staff Report on Grid Modernization*, St. Paul, MN (2016).

http://morethansmart.org/wp-content/uploads/2015/06/MNPUC_Staff_Report_on_Grid_Modernization_March2016.pdf.

The PUC defined an integrated modernized grid as one that

- a. ensures continued safe, reliable, and resilient utility network operations
- b. enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and DERs
- c. provides for greater system efficiency and greater utilization of grid assets
- d. enables the development of new products and services
- e. provides customers with necessary information and tools to enable more informed control and choice regarding their energy use
- f. supports a standards-based and interoperable utility network

Benefits of a Modernized Grid

For Customers

- a. gives customers the information they need to manage their electricity use and help control or contain costs
- b. gives customers more electricity options (renewable energy, time-of-use rates, etc.)
- c. allows utilities to pinpoint outages rapidly, and sometimes in advance
- d. enables customers to use demand response products and services (where customers are paid to use electricity at specific time intervals or in response to grid conditions and needs)
- e. optimizes the efficient use of the existing electric system while maintaining its resilience (e.g., meets demands for electricity drawing on both supply-side and demand-side resources in ways that minimize the need to build new “peaking” plants and help keep costs down for all by potentially deferring infrastructure investment)
- f. provides very high-quality power to those customers who need it in an increasingly digital economy (electricity with few sags in voltage or frequency)
- g. coordinates the use of all types of electricity resources, from central power plants to DERs (e.g., solar, electric vehicles, and other forms of energy storage), allowing interested customers to interact effortlessly with the electric system
- h. enables the mass deployment of electric vehicles

For the Utility and Grid Operator

- a. has lower costs for repair and replacement of equipment because it alerts utilities about equipment predicted to fail (asset performance management) rather replacing old equipment on a set schedule whether it needs it or not
- b. can “heal” itself after a disturbance (e.g., from storms)²⁶
- c. provides greater visibility about what’s happening at the grid edge
- d. provides people with price information and signals that provide economic incentives to utilize electricity in a manner that optimizes system operations, leading to lower costs for all
- e. enables more distributed, clean energy technologies paired with energy storage devices that make the grid more resilient

²⁶ This requires a system of sensors, automated controls, and advanced software that relies on real-time data to detect and isolate faults and to reconfigure the distribution network to minimize affected customers.

In the e21 Initiative's consensus phase I report, participants agreed that the rapid improvement and declining costs of distributed energy technologies, such as solar, along with new customer demands and public policy requirements are driving the need for a modern grid that is cleaner and more intelligent, efficient, reliable, resilient, safe, and secure; and a grid that is more flexible in its ability to integrate a wide diversity of DERs and that enables customers to manage (and potentially reduce) their electricity costs.

To achieve such a system, the e21 Initiative's phase I report recommended that Minnesota

- develop a transparent, forward-looking process for modernizing the grid (which the Minnesota PUC now has underway)
- identify ways to achieve a more flexible distribution system that can efficiently and reliably integrate cost-effective DERs (e.g., efficiency, demand response, distributed generation, energy storage, electric vehicles, distributed intelligence)
- pursue opportunities to reduce customer and system costs by improving overall grid efficiency and better utilizing existing system assets (i.e., improving the grid's load factor).

Charge of the Grid Modernization Subgroup

The grid modernization subgroup aimed to contribute to the implementation of the above three recommendations by

- a. proposing a set of objectives for grid modernization in Minnesota and outlining the functions and technologies a modern grid will need
- b. suggesting an overall approach to grid modernization
- c. offering next steps and recommendations that can usefully complement the Minnesota PUC's ongoing grid modernization process.

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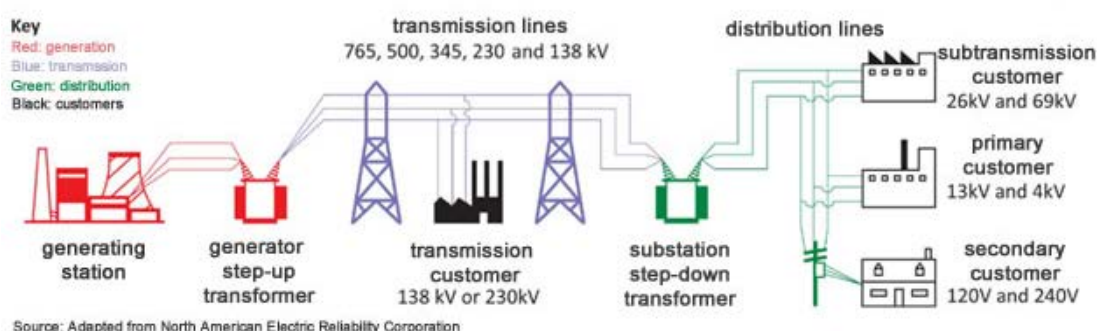
** An asterisk indicates they are no longer at their organization and are no longer participants in e21. Also note that participants that have changed organizations since the start of e21's phase II have their new position and organization in parentheses.*

Section I:

Why Modernize the Electric Distribution Grid?

The electric distribution system that we all rely upon daily has had a relatively simple design for more than 100 years (see Figure 1), and its job was straightforward: to take electricity produced at large centralized power plants, send it long distances over bulk transmission lines, and then, in one direction, send it through distribution lines to end users such as factories, businesses, and homes.

Figure 1. The Electric Grid: Generation, Transmission, and Distribution



Our electric system has worked so well that most of us take it for granted. However, today it faces a long list of pressures including aging infrastructure (much of it was built in the 1960s and 1970s), demands from some customers for greater reliability and cleaner energy, and the emergence of a wide range of new distributed technologies that the traditional electric grid was not designed to accommodate (see the box below for a list of the key drivers for grid modernization).

Drivers Spurring the Need to Modernize the Grid

Changes in Customer Preferences and Behavior

- Customer preferences are growing for increasingly clean electricity and the option to produce it themselves, purchase Renewable Energy Credits, and/or buy it directly from a renewable energy facility that either a utility or third party owns and operates.
- Customers are increasingly interested in better understanding their electricity use and costs, and therefore are increasingly interested in easy access to their real-time, detailed electricity use data.
- Customers are becoming more energy efficient. This reduction in electricity sales calls for reexamination of how best to cover the cost of maintaining and reinvesting in the grid.
- Some customers desire even higher quality and more reliable power supply, due to the greater reliance on electricity in our more digital economy.

Changes in Energy and Information Technology

- e. Rapidly emerging DERs, declining in cost, need to be integrated into the grid. While DER penetration differs significantly by state and by utility, according to the Institute of Electrical and Electronics Engineers, “the vast majority of new generation currently being connected to the grid is through the distribution system.”
- f. The emergence of the “internet of things” means that a growing number of appliances have the ability for two-way communication with the electric grid and can be controlled remotely. This “distributed intelligence,” in the form of communications and control technologies, enables nearly every grid element to send and receive information, and begs for a much more robust, interoperable communications network and cyber-security strategy than currently exists.

Changes in Public Policy

- g. Existing public policy calls for more renewable energy and significant reduction in greenhouse gases.
- h. Recent policies and programs are being implemented to encourage DERs and help overcome market and regulatory barriers to implementation.
- i. There is constant pressure to reduce overall costs while improving the electric grid’s resiliency, reliability, and security.

Among these drivers of change, perhaps the most influential is the emergence of DERs, including generation resources such as solar. As the penetration of DERs increases on the distribution grid, we are moving from a highly controlled, centralized system—where the independent system operator coordinated which power plants to switch on and when—to a much more decentralized system in which distribution grid operators may need to coordinate the dispatch of DERs. e21 participants recognized that there is also substantial opportunity for adoption of DERs (such as demand response) for large customers that may connect directly to the transmission system as opposed to the distribution system. While many principles discussed below may apply to these larger-scale DER opportunities, for focus and clarity this white paper deals with the distribution system.

The emergence of distributed energy technologies also means that the grid—which was originally designed to carry electricity in only one direction—must now operate more dynamically in a multi-directional manner: electricity now flows not only from the transmission system down to the distribution system, but also sometimes flows back into the transmission system from generation technologies connected to the distribution system. The impacts of this decentralization of electricity production are most acute on the distribution system due to the nature of DERs, which are sometimes controlled by someone other than the utility.

The local distribution system for electricity is, itself, undergoing changes too. The distribution system has traditionally operated as a collection of independent radial feeders with all of the power coming from one source, the transmission grid. Increasingly, though, the hub-and-spoke system is being reshaped by customer density and the interconnection of new distributed resources throughout the distribution system. These new DERs include customer-driven generation, load management, energy efficiency, and advanced monitoring, and their diverse placement throughout the distribution system creates a very complex and dynamic distribution grid.

While connecting more electricity resources to the distribution grid may sound simple, a large number of factors determine the characteristics of a given location on a distribution system feeder. A key motivator for modernizing the grid is to allow distribution planners and operators to more proactively address some of these considerations, which include:

Maintaining power quality within a more dynamic system. DERs and loads must interact with each other so as to not cause nuisance or damaging impacts, as may happen if harmful voltage levels, harmonic content, or flicker are allowed to develop. Thus, it is important to develop and implement tools and systems to help enable the desired interconnections and maintain required frequency and voltage.

Designing distribution circuits to accommodate DERs. Considerations here include: How the size of electrical loads are matched with the size of DERs (what amount of generation will be put back on the grid). The size and type of the distribution transformer supplying that location (generally, smaller transformers can be overloaded by distributed generation systems back-feeding the distribution grid). The size and length of the wires supplying that location (generally, smaller wires have less capacity and more dynamic voltage swings).

Ensuring that transmission and substation characteristics can accommodate DER. This includes paying attention to

- the distance between the DER and the substation (the farther the interconnection location the greater the voltage swings can be)
- the capacity of the substation (larger substations can typically support larger distributed generation systems)
- the “stiffness” of the transmission system supplying the distribution substation (a stiffer transmission system reduces voltage dynamics)²⁷
- the capacity of the substation, and whether there is hosting capacity available for DERs. Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system²⁸
- the electric protection system—causes of trips and equipment failure in that section of the feeder (i.e., size and type of the fuse or breaker)

This is just a partial list and does not include customer-driven solutions such as smart inverters. While none of these considerations are deal-breakers for moving to a more decentralized system of electricity generation, they do illustrate the non-trivial factors that grid planners must take into account if we are to maintain a safe, reliable, and cost-effective electric system going forward. Utilities are, and will continue to, evolve the electric grid to meet the needs of users.

The original job that electric distribution systems were asked to do—move electricity in one direction from the transmission grid to the end user—is changing dramatically; and the way we plan, design, and operate the system will need to be modernized to match the new demands of the day.

²⁷ In rural areas, transmission systems are typically weaker than urban areas, and the electric grid cannot always support larger distributed generation systems due to larger voltage swings.

²⁸ *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* (Palo Alto, CA: Electric Power Research Institute, 2016).

Section II:

An Approach to Modernizing the Electric Grid

Having established the reasons why Minnesota should modernize its electric grid, in this section we outline an approach for doing so. Its five basic elements are the following:

- a. **Set clear objectives.** An essential first step toward grid modernization is for Minnesota to be clear about its objectives for doing so. In other words, what do we want a modern electric grid to do besides deliver the electricity that it always has? Early clarity on objectives is critical since they will inform how all other issues are handled.
- b. **Identify the key functions the grid must have to achieve each objective.** Much discussion around grid modernization to date has focused on individual technologies, such as advanced metering or distributed solar photovoltaics. The approach presented here explicitly elevates the *functions* that various technologies can fulfill (i.e., what problems can they solve) above the individual technologies themselves. Which functions are needed, and when, will differ based on the penetration of DERs on the distribution system, the nature of the customer base in a given utility service territory, and other factors. But the salient point is simply that each function should contribute to one or more grid modernization objectives (see ‘a’ above).
- c. **Identify and invest in those foundational technologies that enable the desired grid functions, and assess technology performance over time to ensure the technologies are being harnessed to meet explicit objectives and functions.** Here, too, which technologies are needed, and in what order, will depend largely on the degree of DER penetration on a given distribution grid and how complex the market and operational characteristics of the distribution grid have become (see Fig. 1 below).
- d. **Facilitate comprehensive, coordinated, transparent scenario-based distribution system planning.** Distribution system planners are currently faced with the challenge of planning for the pace and location of DER growth, which to date has been treated as an external condition to react to, rather than a resource to be planned for and harnessed. Yet ever-more accurate forecasts of DER growth can be developed, similar to how forecasting of wind resources has improved. There is also an opportunity to use probabilistic scenario planning and a standard set of DER growth scenarios (much the way transmission planners have done) to create long-term plans for accommodating the scale and location of DERs on the distribution system. Such scenario planning works best at a scale where a significant diversity of DERs is present and will be less accurate for smaller systems. Unlike transmission planners, who have the benefit of long lead times planning for transmission investments, most distribution planners must react more rapidly to local changes on the distribution system, such as the addition of new businesses and housing developments.

In addition to better forecasts and scenarios, utilities will need to perform systematic hosting capacity analysis of each distribution feeder and substation—as a screening tool—to quantify the level of DERs possible on the distribution grid. Utilities will also need to conduct locational value mapping to determine where DERs can help solve problems on the grid, where they may cause problems, and/or where adding them may prompt the need for additional investment (such as upgrading a transformer or substation).

Lastly, in addition to developing longer-term scenarios that attempt to capture the likely range of potential DER penetration on the distribution grid, utilities may also need to conduct periodic—perhaps annual—hosting capacity reviews to avoid operating with out-of-date information (or providing out-of-date information to interested third parties), given that conditions on the ground are always changing.

- e. **Identify the current stage of grid evolution and decide on an appropriate operational model for the distribution grid, including how it will interact with the bulk transmission system and the regional electricity market, and how it will handle market transactions if/when necessary.** In their paper for Lawrence Berkeley National Laboratory, *Distribution Systems in a High DER Future: Planning, Market Design, Operation and Oversight*, Paul De Martini (California Institute of Technology) and Lorenzo Kristov (California Independent System Operator) offer a useful way of conceptualizing the evolution of the distribution system as customer adoption of DERs grows (Figure 1). The stages of DER penetration may not be neatly sequential, nor does

Figure 1 suggest that stage 3 is the inevitable or desired destination. The point is for states to understand where on this continuum they are (most are at stage 1) and then choose where they wish to be and prepare accordingly. The authors lay out several different models for who could be made responsible for

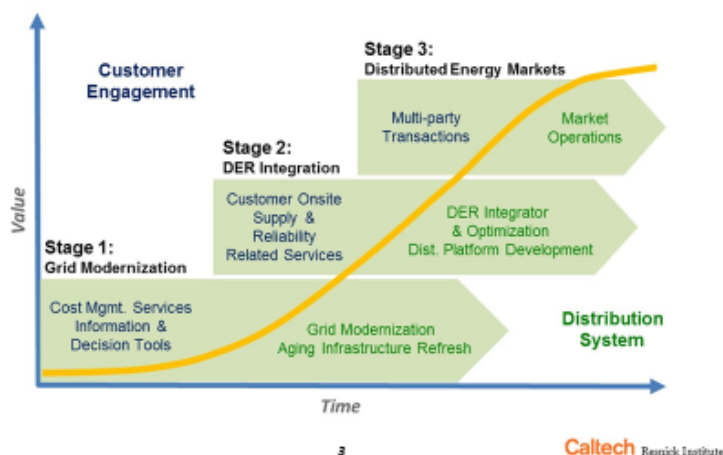
managing grid operations, market transactions among utilities, customers, and third parties, and interactions with the transmission system operator. The options range from the transmission system operator managing all transactions for both the transmission and distribution system, to a model in which the operator of the distribution system manages all operations for its distribution service territory and coordinates a single

Figure 1.

Evolution of Customer & Distribution Grid

3 Stages of Evolution as DER Adoption Grows & Market Opportunities Expand

Utility functions will evolve over time as customer adoption of DER grows and the opportunity to enable the net value created in this transition



aggregate of all DERs at each point where the distribution system connects with the transmission system (the transmission/distribution interface).

Finally, the authors usefully identify two key ways that states can prepare for higher penetrations of DERs. States can

- use the replacement of aging infrastructure and investments needed for electricity reliability reasons to increase the distribution grid's ability to accommodate more DERs (for example, standardizing on fewer, but slightly larger, equipment/wire sizes when replacing old ones)
- make prudent investments that can lay the foundation for the future as well as provide immediate benefits. These potential investments include
 - advanced metering infrastructure
 - advanced distribution management systems
 - distribution sensing, visualization, and analytics
 - field switch/device automation
 - higher bandwidth/lower latency operational communications networks

Objectives for Grid Modernization in Minnesota. After careful thought and discussion, e21 participants propose the following objectives for grid modernization in Minnesota:

- Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed
- Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers
- Objective 3: Enhance the system's ability to integrate DERs and other new products and services in a cost-effective and timely way
- Objective 4: Improve the environmental performance of electricity services
- Objective 5: Promote optimized and cost-effective utilization of grid assets

The remainder of this section takes each of these objectives in turn and briefly outlines the grid functions and technologies needed to achieve them.

Objective 1: Maintain and enhance the reliability, safety, security, and resilience of a more distributed, dynamic, and complex electric grid, as and where needed.

Background. This first objective is largely about identifying the features of the existing electric distribution system that we value and still need while accommodating DERs. To achieve this objective, utilities will need efficient, cost-effective, real-time ways to anticipate infrastructure repair and replacement needs, detect and repair faults and outages on the distribution system, and reduce the impact of prolonged outages by improving their speed in restoring service after extreme events (for example, weather or cyberattacks). Per the discussion in section I, meeting this first objective will also require utilities to map where on the system DERs can provide the greatest benefit (sometimes called locational value mapping) and will require regulators to establish a compensation framework that encourages DERs to locate in those places. Channeling DERs to the best locations will contribute to several aspects of this objective, including safety and reliability.

As for achieving a grid that is both resilient and secure, the shift toward more DERs is double-edged. On one hand, such resources, almost by definition, make the electric grid more resilient by virtue of being distributed and therefore less susceptible to any single disruption (the parts of New York that were still illuminated after Superstorm Sandy were generally those served by DERs). On the other hand, managing a more complex, more highly distributed system will require a new communication system linking its many elements. Such an extensive communication system will, by design, create thousands (or millions) of potential access points for cyberattack (much as we already see on the internet).

While we recognize the fundamental importance of ensuring cybersecurity, this white paper will not address it in any depth. e21's discussion and recommendations presuppose that all parties interconnecting with the grid will employ and maintain robust cybersecurity measures, and we recognize the Minnesota PUC's role in supporting such requirements.

Lastly, it is important to note that different types of electricity customers desire different levels of reliability, security, and resilience. For example, the level of power quality and reliability that a homeowner finds acceptable will be quite different from the level acceptable to a data center, for which even small fluctuations in voltage can cause problems. Therefore, achieving objective 1—and the additional investments it will require—should be tempered by what different customer classes need and are willing to pay for.

Key functions that a modern grid must have in order to achieve objective 1 include utilities having the following capabilities and conditions

- a. incipient fault detection
- b. automated fault detection
- c. fault location and isolation, and service restoration
- d. operational standards, including how the distribution system will interact with the bulk electricity market managed by the Midcontinent Independent System Operator (MISO)
- e. workforce optimization (e.g., having the right people in the right place at the right time)
- f. situational awareness for field crews
- g. remote preventive maintenance inspection (will be different by utility)

Foundational technologies that enable these functions include

- a. intelligent field devices (e.g., digital relays and controls)
- b. field area networks
- c. distribution management systems
- d. better information from global information systems
- e. field mobility tools (e.g., a tablet that shows real-time state of the system on power flows and location of field crews)

Objective 2: Enable greater customer engagement, empowerment, and options, including the ability to manage and potentially reduce electricity costs for all customers.

Background. A modernized grid must enable customers to gain greater insight into the sources of their electricity and understand their electricity use profiles and costs. Making more information easily accessible and understandable will facilitate customers' ability to understand and manage their costs, reduce their environmental impact, take advantage of new technologies, and generally manage their individual electricity preferences.²⁹

Two interrelated prerequisites for accomplishing this objective are advanced meters and improved customer access to their electricity usage data. Today's advanced digital meters are able to collect electricity usage information at hourly or 15-minute intervals, whereas current metering infrastructure for most customers is only able to provide data once a month or once a day. An integral part of customer engagement and empowerment is giving customers easy access to their electricity usage data since without the necessary information it is impossible for them to make informed decisions about their electricity use. The Minnesota PUC's recent proceeding³⁰ on the use and availability of customer electricity usage data addressed fundamental questions about how the data could be made available, while safeguarding customer privacy and the anonymity of that data.

The proliferation of new technologies and devices is making it easier to manage electricity use in near real-time, and they are increasingly available directly to customers, at declining costs. Smart thermostats and home area networks can help customers manage their electricity use and provide automated control and convenience by connecting to and communicating with the digital devices throughout the person's home—from lights and appliances, to the heating and cooling system—to optimize their efficient use. Pairing these programmable energy management technologies with time-of-use rates could enable customers to effortlessly control their electricity costs, while helping to optimize grid operations.

Other enabling technology, such as advanced metering infrastructure, can communicate cost and pricing information to a customer's automation and control systems at their home or business, again making more transparent the utility's costs of providing electricity service at any given time. The promise of these technologies is that they will allow customers to manage their electricity use and their interaction with the grid without thinking about it. A customer can automatically charge an electric vehicle or cycle a refrigerator off and on (without affecting the inside temperature) on a schedule that reduces demand on the electric system or shifts it to a more optimal time, dramatically improving the efficiency of the entire system and reducing costs

²⁹ Or the ability of a customer's authorized third party who may be assisting them.

³⁰ See *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities*, Minnesota Public Utilities Commission Docket No. E,G-999/CI-12-1344 (Order based on December 1, 2016 hearing is forthcoming).

for all customers. While not everyone may want, or be able to afford, some of these technologies and services, making them available to people at all income levels would make it both possible and easy for customers to use electricity at the most affordable times and operate their homes or businesses as efficiently as possible.

Many customers will be happy to stick with conventional grid electricity produced with an evolving mix of fuels—increasingly natural gas, wind and solar, some remaining coal and nuclear—and other customers will want to invest in producing their own power (for example, from solar, either directly on their roof or through shares in a community solar project), and a modernized grid must accommodate them all.

Finally, achieving the customer engagement called for in objective 2 will require utilities to develop an even more nuanced understanding of what their various customers want, develop more sophisticated ways of meeting those needs, and educate their customers about changes to electricity services and the grid.

Key functions that a modern grid must have in order to achieve objective 2 include

- a. the ability to handle two-way flows of information among the actors and connected devices on the system. Examples of relevant information are real-time prices and electricity use, control parameters such as voltage and power factor, and information designed to educate and inform customers of their options and opportunities for savings and reduced environmental impact
- b. the ability to effectively manage two-way flows of electricity

Foundational technologies that enable these functions include

- a. user-friendly customer portal/hub that displays relevant electricity and price information
- b. home area network at the customer's site
- c. advanced metering infrastructure and communication networks including field area networks
- d. a secure protocol via the internet or cellular option

Objective 3: Enhance the system's ability to integrate DERs and other new products and services in a cost-effective and timely way.

Background. We are evolving from an electric system with relatively few actors on it, characterized by large centralized power plants sending electricity in one direction to the end user, toward a system with potentially thousands of “prosumers” participating in it (sometimes acting as *consumers*, using electricity from the grid and sometimes acting as *producers*, making their own and selling the excess back to the grid). In this more complex, highly distributed system there will be increased need for a real-time orchestra conductor to coordinate activities on the system minute-to-minute and ensure that it operates efficiently, safely, reliably, cost-effectively, and securely. In Minnesota, that function is provided by the local utilities.³¹

In any case, achieving objective 3 will require changes in how we operate the grid, compensate DER providers (e.g., solar), determine who has access to information about the best locations for DERs on the grid, institute changes to the interconnection process and tariffs charged for

³¹ As distribution systems evolve, some states may choose to establish a separate entity to manage distribution grid operations.

connecting to the distribution grid, and modify the interoperability standards that allow different elements of the electric system to talk with one another seamlessly.

Taking these in turn, the way we operate the electric grid is already changing. Since there are many sources of variability on the system—level of demand, net imports and exports of electricity, distributed generation such as wind and solar, etc.—system operators use a variety of supply- and demand-side resources to meet the net load at any given time of day (the amount of electricity demand that still needs to be met by centralized generation after accounting for all of these variables). In the future, system operators won't only match generation to meet the load, but will increasingly manage the load to match available electricity generation. In other words, the legacy terms of “baseload,” “intermediate,” and “peaking” no longer reflect how grid operators think of balancing supply and demand.

Today's large, liquid electricity markets can re-match net demand with net supply every five minutes across the entire MISO region. On the distribution grid, this reconciliation between supply and demand will be done by the operator of the distribution system. Information from the distribution operator will need to flow up to the transmission operator and vice versa.³² A more integrated, networked, and intelligent electric grid makes this kind of coordination possible, and it paves the way for energy resources at the customer and distribution grid level to contribute to the reliability of the regional electric system. The goal will increasingly be to find ways to optimize and extract value from one end of the electric system to the other, from end-use customers through distribution systems, regional transmission systems, and centralized power plants.

Next, achieving objective 3 will require accurately compensating DER providers for the full value they deliver to the grid and charging them fairly for the costs they impose from being connected to it. The current net energy metering model of reimbursing providers of DERs, such as solar, at the retail electricity price by crediting against a customer's electricity consumption is leading to heated debates about whether DER providers are paying their fair share of grid infrastructure costs and whether there are unfair cross-subsidies taking place. These debates are a symptom of stakeholders in the electric system not yet having worked out what the appropriate rate design and compensation methodology should be between DER providers and utilities.

Current net energy metering programs focus solely on the total production of a DER without taking into consideration the location of the asset or what the grid's needs are at any given time (for energy, capacity, voltage support, frequency regulation, etc.). Minnesota's value-of-solar tariff is an example of trying to capture solar's full range of costs and benefits in the price solar providers get. Minnesota will need to determine whether to implement a suite of technology-specific tariffs for each form of DER or identify a set of services necessary to maintain the distribution grid and then allow DERs to compete to provide those services. Minnesota will need to determine the tradeoffs and benefits of each option in order to meet this objective.

Next, data about the distribution grid itself will also be essential to optimally integrating more DERs, including where the best locations are for adding DERs and when the system is likely to need energy, capacity, demand response, or ancillary services such as voltage support and frequency regulation. When customers, developers, and other third parties have access to relevant grid-level information they will more naturally locate DERs in the best places on the grid if there are tariffs that reward them financially for doing so and penalize them for locating in

³² See Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future, Future Electric Utility Regulation, Report No. 2* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015).

places where more DERs would impose net costs on the system. When relevant transparent information is paired with accurate prices, an efficient market can start to function.

Minnesota could also benefit from updating its interconnection standards and tariffs for DERs. A more open, streamlined, and transparent interconnection process utilizing more information about the state of the grid can alleviate delays and complaints and result in savings to the customer and the grid. As for updating current tariffs, efforts such as California's Rule 21 and the Federal Energy Regulatory Commission's small generator interconnection procedures tariffs provide Minnesota examples to draw from.³³

Along with updating the tariffs, adding new grid functionalities that are now mainstream can enable additional benefits to the utility and the customer. For example, smart inverters can enable two-way communications between grid operators and DERs, and they can provide low-voltage and low-frequency ride-through, volt-VAR support, black-start capability, and islanding that will allow microgrids to function alone or connected to the larger grid. Given their wide range of functions, smart inverters are increasingly seen as a de facto part of any customer-sited resource.³⁴

Finally, since the electricity sector is a standards-driven industry, having open and transparent standards must be a bedrock principle of grid modernization. These standards support interoperability of devices, on both the utility and customer side of the electric meter.

Interoperability and use of open standards help utilities avoid being locked into a single vendor for a given technology, which ensures an open, innovative, and competitive market for utility- and customer-focused products. When utilities, regulators, and other stakeholders identify and agree upon these foundational standards early, such as IEEE 1547, UL 1741, and IEC 61850, this can lower barriers to entry for new products and services, and lower overall costs to the utility by allowing for competition among vendors. Cost savings can then be passed through to customers.

³³ California's rule concerns the technical requirements for interconnecting solar to the grid. On the Federal Energy Regulatory Commission's tariffs, see <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>.

³⁴ The current standards supporting the interconnection tariffs IEEE 1547 and UL 1741 have been updated or are currently being updated to allow for the advanced functionality from smart inverters. Work continues on communication standards (DNP 3 and IEC 61850) that can help ensure that the utility is in communication with its equipment as DERs begin to impact the distribution grid.

Microgrids as Another Feature of a More Distributed Electric Grid

One might think of microgrids as a larger distributed energy resource. Microgrids are collections of electricity users (loads) and distributed energy resources to serve them (think university campus). Microgrids operate to provide electricity during storms, at times of peak load, or when equipment in the area fails or is out for maintenance. Their key features are that they

- are locally controlled
- can function in two modes, connected to the traditional grid or as an electrical island

This “islanding” function can be especially beneficial in situations when severe weather or other disruptions have caused the main grid to lose power. That said, disconnecting and reconnecting to the main grid requires special planning and sophisticated software to ensure that it is done safely and without compromising the functioning of either the microgrid or the main distribution system.

The main barrier to greater microgrid deployment is simply the cost to implement the distributed generation and required storage, but as the costs of both fall, microgrids will likely become even more common. For example, Dakota Electric in Minnesota has roughly a dozen microgrids in places where a member’s campus is isolated from the rest of the Dakota Electric system.

Lawrence Berkeley National Laboratory cites the many benefits of microgrids for both utilities and customers, including “improved energy efficiency; minimization of overall energy consumption; reduced environmental impact; improvement of reliability of supply; network operational benefits such as loss reduction, congestion relief, voltage control, or security of supply; and more cost-efficient electricity infrastructure replacement.”

For more information, see:

- Lawrence Berkeley National Laboratory: <https://building-microgrid.lbl.gov/about-microgrids>
- “Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance.” 2013. Prepared by the Microgrid Institute for the Minnesota Department of Commerce. http://mn.gov/commerce-stat/pdfs/CHP_pdfs/MN-Microgrid-WP-FINAL-amended.pdf
- California Public Utilities Commission. 2014. “Microgrids: A Regulatory Perspective.” http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDMicrogridPaper414.pdf

Key functions that a modern grid must have in order to achieve objective 3 include

- a. real-time, model-based control systems for grid operators
- b. additional work on uniform standards (e.g., smart inverter and communications standards)
- c. interoperability among components connected to the grid
- d. the evolution of market rules in ways that improve system flexibility including:
 - improved system scheduling and dispatch
 - improved procurement
 - payment for ancillary services
 - incentives for load following and ramp management
- e. hosting capacity assessment
- f. development of distribution-level locational marginal prices

Foundational technologies that enable these functions include

- a. advanced metering infrastructure
- b. demand response mechanisms such as automated load control/response and real-time pricing
- c. DER management system
- d. energy storage
- e. field area networks
- f. smart inverters

Objective 4: Improve the environmental performance of electricity services.

Background. Minnesota has established ambitious statutory goals for reducing greenhouse gas emissions to 15 percent below 2005 levels by 2015, 30 percent below those levels by 2025, and 80 percent below by 2050.³⁵ In addition, as cited in the *Minnesota PUC Staff Report on Grid Modernization*, “the ‘reasonable rate’ statute requires the [Minnesota Public Utilities] Commission to set rates to encourage energy conservation and renewable energy ‘to the maximum reasonable extent’; 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.’”³⁶

Grid modernization can help achieve these policy goals by creating a platform for optimizing the environmental performance of the electric system as a whole. This includes better integrating distributed renewable generation technologies, increasing the responsiveness of customer loads, and giving customers new tools to save electricity, as well as optimizing the use of large-scale renewable energy assets and doing better forecasting and planning to integrate more renewable and low-carbon resources.

Grid modernization technologies also facilitate more accurate measurement of energy savings from efficiency improvements, and these can help verify the consistency and persistence of those energy savings over time. The new data collection and communication capabilities of a modern grid may also help identify specific new energy efficiency opportunities and ways of operating at the systems level that improve the efficiency and environmental performance of the electric grid overall.

This objective poses an important policy question for Minnesota about the role of DERs in achieving the state’s environmental goals. Most DERs, such as energy efficiency, solar, or demand response, reduce greenhouse gas emissions.³⁷ Yet when it comes to generation technologies, economies of scale still often favor utility-scale renewable energy facilities over smaller, more decentralized distributed generation in terms of cost and integration with the grid. However, if only the avoided cost of DERs is taken into consideration, this may not appropriately identify and allocate the non-generation, time- and location-specific benefits they can provide, such as peak reduction, voltage, and frequency regulation or grid resilience. Clarifying the environmental objective of grid modernization allows policymakers to assess which distribution grid technologies will have the highest environmental benefit from a systems perspective.

³⁵ Minnesota statute §216H.02

³⁶ Additional quotations are taken from Minnesota statute. See *Minnesota PUC Staff Report on Grid Modernization* (p. 11) for details.

³⁷ However, the use of diesel-fired back-up generation may have local impacts.

Achieving objective 4 is about increasing and optimizing the mix of cost-effective energy efficiency and zero- or low-carbon electricity resources on the electric system, including customer-driven and community-scale DERs. The essence of this objective is for Minnesota's electric system to provide safe, reliable, affordable, and secure electricity service with a declining environmental footprint that, at a minimum, achieves the state's statutory goals.

Key functions that a modern grid must have in order to achieve this objective include

- a. the ability for loads that are flexible (i.e., loads that don't care when they receive electricity) to take advantage of renewable energy generation by receiving signals telling them when there is excess renewable energy available or, more generically, low market prices. Examples of flexible loads include water heating, electric vehicle charging, large appliances (e.g., refrigeration including defrost), limited scheduling of heating and cooling, and energy storage.
- b. distribution grid operators are able to “see” the distribution-level-connected resources on the system (end-to-end visibility)
- c. dynamic voltage control
- d. load management, including demand response, that reduces overall electricity used or shifts supply to lower-carbon electricity sources
- e. new communications, metering, and control technologies that open up new market segments for intelligent and systems-based energy efficiency
- f. the ability to maximize reliable penetration of renewable distributed generation and accelerate interconnection of those technologies
- g. the ability to monitor and verify the performance of energy saving and renewable production technologies

Foundational technologies that enable these functions include

- a. advanced metering infrastructure
- b. field area networks
- c. home area networks
- d. model-based control systems
- e. more intelligent energy management systems that better match up renewable generation resources with load

Objective 5: Promote optimized and cost-effective utilization of grid assets.

Background. Utilities have planned and operated the electric system to meet the peak demand in any given year and to handle the instantaneous demand of customers—plus a little extra (the reserve margin) to make sure there is always enough electricity available, including when there are unexpected power plant and/or transmission line outages.

This means that most of the time there is significant excess electricity-generating capacity—though much of that capacity is composed of peaking units that are not meant to run full time—a bit like building a parking lot big enough to accommodate a few weeks of holiday shopping per year. If peak demand (e.g., when everyone is flipping on their air conditioning in the summer) could be reduced and/or shifted, it would save both utilities and customers money because we could avoid building additional generating capacity to meet that peak demand.

Therefore, objective 5 is about (1) optimizing the alignment between generation and load to better utilize the existing system, and (2) continuing the evolution toward more fully using both

customer-driven resources (such as distributed generation, energy storage, and demand response) and the utility's resources to meet demand at any given time. This will improve the electric system's load factor so that power usage is relatively constant (with fewer peaks) and thus help avoid needing to build additional power plants.

Another potentially cost-effective opportunity for meeting customer load is demand response. Traditionally, this involves paying some customers to reduce their electricity use during the most expensive times, for the utility, of peak demand. The simplest form of demand response, particularly from a resource planning perspective, may be to compensate large load customers (>10 megawatts) to reduce their electricity usage during system peaks. Many large customers are interconnected to the transmission grid as opposed to the distribution grid and, therefore, were not the focus of e21's phase II deliberations. Another form of demand response with a similar outcome would be for many smaller customers to aggregate their load, but this may require changes in rules or regulations in Minnesota to allow for load aggregation that, for example, could be bid into MISO.³⁸ Implementing either kind of demand response could reduce greenhouse gas emissions and minimize the costs of the system for everyone by meeting peak demand via conservation rather than generation of more coal- or natural gas-fueled electricity.

Demand response, however, is not limited only to peak-time reductions in electricity use. As demand response becomes even more integrated into utility operations,³⁹ it can serve a wide variety of other uses, including automatically *increasing* consumption if there is excess renewable electricity available. Certain kinds of commercial and industrial loads, for example, may be well suited to particular renewable generation (e.g., nighttime operations when wind generation is high). It is worth noting that Minnesota already leads the nation in load management, with many utilities having had significant load management for 30 or 40 years, and some since the 1950s.

In addition to avoiding the building of underused or unneeded power plants, Minnesota has an opportunity to further right-size its electric distribution system. Doing so could avoid costly system upgrades and reduce system losses,⁴⁰ as generating and moving electricity inevitably

³⁸ Minnesota Public Utilities Commission Docket No. E-999/CI-09-1449, "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into the MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A" (April 16, 2013); Minnesota Public Utilities Commission Docket No. E-999/CI-09-1449, "Order Accepting Filings, Requiring Expanded Cost-Effective Demand Response Investments, and Soliciting Further Comments" (August 31, 2012).

³⁹ This discussion is largely limited to utility demand response programs. As identified in the *Minnesota PUC Staff Report on Grid Modernization*, the potential role of third-party demand response providers may also enable greater demand response potential. Although Minnesota PUC policy currently prohibits third-party demand response providers, stakeholders in the Minnesota PUC grid modernization proceeding noted that it may be time to reconsider that decision.

⁴⁰ See the following presentations at the Minnesota PUC Grid Modernization Meeting, October 30, 2015 (<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F39616C8-E8F7-4F4C-B704-80D9C84B7101}&documentTitle=201510-115146-01>): Chris Neme and Rich Sedano, "U.S. Experience with Efficiency as a Transmission and Distribution System Resource" (Hinesburg, VT: Energy Futures Group; Montpelier, VT: Regulatory Assistance Project; 2012), <http://www.raponline.org/wp-content/uploads/2016/05/rap-neme-efficiencyasatanddresource-2012-feb-14.pdf>; Damian Sciano, "Reforming the Energy Vision and its Implications for Distribution System Planning" (ConEd presentation on Brooklyn-Queens Demand Management Program, 2015); and Jeff Smith, "An Integrated Approach to Distribution Planning" (Electric Power Research Institute presentation on the Tennessee Valley Authority and other projects, 2015). Further examples are listed in GreenTech Media, "Demand-Side Resources Can Be Cheaper than Large Infrastructure Upgrades" (2014), <http://www.greentechmedia.com/articles/read/distributed-resources-gain-traction-to-avoid-grid-upgrades>.

means some losses at each transition step, given the laws of physics. Building only as much distribution infrastructure as necessary, and in the right places, will save everyone money and make the system work most reliably. This is why it is so important to understand where DERs are most beneficial on the distribution system and encourage them—through price signals—to locate there.

Finally, while outside the scope of this white paper, achieving objective 5 will likely require some form of time-variant pricing that gives customers accurate information about the cost of using electricity at any given time of day. Electricity is one of the few products that consumers use without knowing the price at the time of use. If applied fairly and with some advance notice, time-of-use rates can optimize the alignment between generation and load to better utilize the existing system, shift electricity use to less expensive times of the day, and avoid the need for new power plants.

Key functions that a modern grid must have in order to achieve this objective include

- a. the ability to optimize the alignment between generation and load using rates and technologies that can reduce the costs of the system for everyone
- b. the ability to effectively forecast DERs at the distribution level

Foundational technologies that enable these functions include

- a. advanced metering infrastructure
- b. dynamic voltage/VAR control
- c. more intelligent energy management systems that better match up renewable generation resources with load
- d. the labor and big data tools (meter data management) with which to analyze the huge amounts of data utilities have—and will have more of) —in order to find ways to optimize the system (e.g., loss analysis on a feeder)

Evolving the Planning of the Electricity Distribution Grid to Meet these Objectives

Achieving the five grid modernization objectives outlined above will require comprehensive, coordinated, and transparent scenario-based distribution system planning. Utilities are already taking steps to plan for a more decentralized electric system. Cost-effectively modernizing Minnesota's electric grid will require additional changes to the way utilities plan for the expected growth in DERs. This planning approach will need to include the following:

- a. proactive, scenario-based, probabilistic distribution engineering analysis that is better able to anticipate the inherently hard-to-predict location, size, and operational characteristics of a wide range of DERs
- b. DER interconnection studies with new criteria, including hosting capacity and locational value
- c. DER hosting capacity analysis
- d. DER locational value analysis
- e. integrated transmission and distribution planning so that both ends of the system understand the implications of DER penetration on the distribution grid

While scenario-based planning would be new for the distribution system, planners have long used it to plan a transmission system capable of serving the most probable future conditions. Transmission planning today is done by considering a number of highly likely system states. Since there is a potentially limitless number of such system states, transmission planners chose “bookends” to reasonably limit the study scope and identify the most important factors to plan

around, and this approach could be adopted for the distribution system as well. That said, there are important differences in the nature of transmission and distribution systems, including the fact that individual distribution systems can be quite different from one another, potentially making the establishment of the bookends of a distribution system somewhat more challenging. Nevertheless, a scenario-based approach to planning may offer the best hope of accommodating the inherently unpredictable growth of DERs.

It's also important to note that the evolution of distribution planning cannot just be about changes in the behavior of utilities. New protocols must also stipulate how all actors on the system will need to behave differently as more DERs connect to the distribution grid. For example, DERs interconnecting to the distribution grid will need to have new responsibilities for ensuring that the operation of their DER contributes to a reliable, affordable, economically efficient system for ratepayers, and regulators will need to clearly establish what those responsibilities are, as conditions of interconnection to the grid.

To speed learning and knowledge transfer it would be valuable to establish a regular opportunity for utilities to share their DER integration experiences with one another and with other stakeholders. This could be part of the annual/biennial systems planning workshop proposed in the *e21 Integrated Systems Planning White Paper*. While utilities are often required to sign nondisclosure agreements with DER providers to protect proprietary information, having a regular forum for exchanging experiences and lessons learned could enable regulators, utilities, intervenors, and other interested parties to develop a shared understanding of the opportunities and challenges that grid modernization presents.

Key functions that a modern grid must have to achieve this evolution toward modernization include

- a. an updated distribution planning process that anticipates and accounts for rapid changes on the distribution system, not all of which are controllable by the utility (e.g., where on the system DERs are deployed)
- b. a comprehensive, scenario-driven, multi-stakeholder process that standardizes data and methodologies to address locational benefits and costs of DERs (this will require the development of standard scenarios as we have for the transmission system)
- c. a thorough assessment of DER hosting capacity by substation, perhaps down to the individual feeder (understanding what the true load is behind the meter and for each feeder)
- d. better forecasting of DERs, including
 - distributed generation—location, quantity, and dependability
 - storage—power and electricity availability, and ancillary services
 - demand response—load control availability
 - conservation and time-shifting
 - adoption and impacts of electric vehicles
 - moving from peak-only forecasting to 24/7 forecasting
- e. clarity on the value of various DERs and how to compensate them, as well as ways to encourage them to locate on the grid where they are most beneficial to the system as a whole
- f. ways of calculating the optimal investment in both wires and non-wires options for meeting system needs

- g. decisions on whether and how DERs will participate in wholesale markets and resource adequacy

Foundational technologies that enable these functions include

- a. planning tools and an agreed-upon planning process that takes into account all the functions outlined in this white paper
- b. intelligent tools to increase hosting capacity
- c. accepted industry practices for identifying hosting capacity and interconnection requirements (as they currently differ considerably by utility)

Section III: Recommendations

As evidenced by this white paper, grid modernization is a sprawling and complex topic. To help manage this complexity, we have organized our recommendations into three categories: planning, customer services and engagement, and operations of the physical system.

Planning

- A. **The Minnesota PUC should provide guidance for utilities on developing standard information sets and platforms for the sharing of hosting capacity.**⁴¹ We ask the Minnesota PUC to issue guidance on providing this information via the web (balanced with security concerns) and determining how frequently the information should be updated (balancing cost and value, as more static systems may require less frequent analysis). We recommend that the more detailed hosting capacity information, beyond that which is available through the publicly available methods, be provided through the interconnection process.
- B. **The Minnesota PUC should review and update Minnesota’s interconnection standards**⁴² **and processes to make the interconnection process more predictable, transparent, timely, and consistent.** As noted by PUC staff in their March 2016 grid modernization report, considerable work has been done on best practices for interconnection of distributed generation upon which to build an updated interconnection approach in Minnesota.⁴³
- C. **Distribution planners should employ scenario-based planning, where beneficial, to plan for and manage the inherent uncertainty of the size, scale, and location of DERs on the distribution system.** In addition to the current set of considerations, distribution planning scenarios should include the implications and opportunities of location-specific siting and operation of DERs (such as electric vehicles, energy storage, distributed generation, demand response, and others). Planning for the addition of DERs on some distribution systems will require moving from peak-only forecasting to detailed forecasting—potentially hourly—to model the net load characteristics on the different parts of a feeder. The Minnesota PUC should require utilities to develop or acquire appropriate tools and processes to enable such planning.⁴⁴

Customer Services and Engagement

- D. **The Minnesota PUC should use a multi-interest stakeholder process to determine the services and benefits that DERs receive from the grid and can provide (including environmental benefits) to meet the electric grid’s needs, recognizing that the**

⁴¹ Among the issues for consideration is how best to allocate hosting capacity among DER providers in a transparent way.

⁴² Minnesota Public Utilities Commission Docket No. E-999/CI-16-521, “In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611” (June 21, 2016).

⁴³ See reports by the Interstate Renewable Energy Council and the Electric Power Research Institute, as well as the Federal Energy Regulatory Commission’s small generator interconnection process.

⁴⁴ Since scenario planning requires the use of sensitive information, the PUC will need to decide which types of information should be made available to the public and which should remain non-public.

services and benefits will differ by DER type, location on the grid, and time of day.

This is a prerequisite to assigning value to the grid services that DERs may provide to the grid and to grid services that DER providers benefit from by virtue of being connected to it. Developing a clearer and fuller understanding of the types of services and values DERs can provide will enable the grid operator to extract greater benefits from DERs and potentially mitigate increased costs to the distribution grid. Clarity on the services and values DERs can provide will allow the grid operator to better optimize the system's operation and design and plan future upgrades to the distribution grid.

- E. **Utilities should establish price signals and payment options that direct DERs to optimal locations on the grid and that provide customers signals for optimal times of electricity use.** The goal should be to strike a balance among objectives that are inherently in tension, including economic efficiency, reliability, simplicity, and fairness.
- F. **Utilities should provide customers with convenient and timely access to as much of their own data as possible, in a consistent format, to enable them to make informed decisions about the timing and amount of their electricity use.**
- G. **The Minnesota PUC should take steps it deems necessary to make sure that utilities implement best practices in all areas of cybersecurity to ensure the availability and confidentiality of information, and the integrity and security of the system.**
- H. **The Minnesota PUC should allow utilities to establish a specific budget to conduct research and development, rather than relying solely on pilot programs to innovate.** As noted in the PUC staff paper on grid modernization:

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.⁴⁵

Minnesota's Statewide Conservation Applied Research and Development (CARD) grant program is a useful example of how research and development can identify new markets, technologies, and savings. Approving a specific research and development budget for some level of experimentation would fit well with the outcome-focus of multi-year rate plans.

Operations

- I. **The Minnesota PUC should ask utilities to adopt cost-effective voltage and volt-ampere reactive optimization appropriate for each utility's system** (often called volt-VAR optimization, or VVO). Volt-VAR optimization is an energy efficiency measure that can lower electricity use without any change in customer behavior. Volt-VAR optimization

⁴⁵ *Minnesota PUC Staff Report on Grid Modernization.*

technologies offer more precise voltage regulation and more efficient power flow than used to be possible or practical.⁴⁶

- J. **Utilities should draw on the existing body of regulation and experience to develop a strategy to utilize smart inverters.**⁴⁷ Smart inverters and new high-speed voltage-regulating systems can continuously monitor and quickly respond to voltage deviations, allowing the effective management of inherently variable DERs and contribute to system stability.
- K. **The Minnesota PUC should establish procedures and tariffs for how and when a distribution grid operator may dispatch and curtail DERs to enable the near real-time matching of generation and load using both supply-side and demand-side resources.** This would include how aggregated demand response will be accomplished and dispatched. The goal should be reliable operation of the distribution system and economically efficient dispatch of DERs for the benefit of all customers.
- L. **The Minnesota PUC should enable utilities to implement appropriate and cost-effective enabling technologies that are prerequisites to achieving grid modernization objectives.** Such systems may include supervisory control and data acquisition (SCADA); advanced metering infrastructure; high-speed and high-capacity communication systems to collect, sensor, and send metering data from the field and communicate control actions to DERs; planning tools; and advanced distribution management systems that use real-time modeling to allow grid operators to effectively manage the dynamic operating conditions that the integration of DERs will create.
- M. **The Minnesota PUC should ensure the use of national standards necessary for effective integration of DERs and interoperability of the grid's communication systems.** These standards include interoperability standards to ensure that devices connected to distribution systems can talk to one another; advanced inverter operational standards; control center-to-control center communication protocols; and utility-to-home area network communication standards. Common standards can reduce total costs and facilitate cybersecurity across the electric system while allowing utilities to implement technologies at different paces based on the technologies' particular characteristics.
- N. **Utilities should use digital and automated communication and monitoring technologies to more accurately evaluate the environmental impact and effectiveness of efficiency and clean energy programs.**

⁴⁶ *Minnesota PUC Staff Report on Grid Modernization*, 24–25.

⁴⁷ For certain types of electricity generation, such as solar photovoltaics, that produce direct current, inverters change it to alternating current to allow the electricity to travel over the distribution grid. Smart inverters have bidirectional communications capability and are able to provide the grid with other ancillary services such as volt-VAR support and islanding. According to the Electric Power Research Institute, smart inverters can double the amount of DER that can be reliably integrated onto the grid, depending on the location; see *Minnesota PUC Staff Report on Grid Modernization*, 17.

Section IV:

Conclusion and Next Steps

The Minnesota PUC has launched a process to explore grid modernization in Minnesota, in part inspired by the early work of the e21 Initiative and its diverse stakeholders. With this white paper and the initiative's ongoing work, e21 aspires to complement—and continue to inform—that PUC process.

To date, the Minnesota PUC has held a series of grid modernization workshops to answer some key questions, including:

- a. What objectives and principles should guide grid modernization in Minnesota and an integrated distribution planning process?
- b. What pathways, both procedural and substantive, are necessary for the PUC to take?
- c. What are the benefits and costs that could result from grid modernization? Are there regulatory steps the PUC should take to balance the costs and benefits for the public interest?
- d. What specific regulatory barriers exist for utilities, customers, or other participants?

In March 2016, PUC staff issued a report summarizing feedback from these workshops and comments submitted from a wide range of interests. The report proposed that the PUC take the following three-phased approach to addressing grid modernization:

Phase 1	Adopt a definition, principles, and objectives for grid modernization
Phase 2	Prioritize potential action items
Phase 3	Adopt a long-term vision for grid modernization

On March 29, 2016, Minnesota PUC staff presented their grid modernization report to the Commission, after which the commissioners adopted the report's recommended working definition and principles for grid modernization and generally accepted the staff report as a helpful foundation for its on-going work on the topic. **The Commission also agreed to:**

- a. **Organize and host additional stakeholder engagement and comment opportunities in the fall of 2016 to foster a distribution-grid planning framework and process well-tailored to Minnesota.**
- b. **Draw on outside technical expertise and best practices to inform Minnesota's approach to grid modernization and distribution grid planning.** For example, thanks to Minnesota's early leadership on regulatory reform, at the request of the MN PUC the U.S. Department of Energy contracted with ICF International to prepare a report on how Minnesota might conduct integrated distribution planning⁴⁸. The Department of Energy views Minnesota as being enough like many other states that what we learn here can be useful to those similar states. Minnesota also has commitments from Lawrence Berkeley National Laboratory to help inform a distribution planning process in Minnesota (the

⁴⁸ ICF International. *Integrated Distribution Planning*. Prepared for the Minnesota Public Utilities Commission. August 2016.

laboratory has produced a Future Electric Utility Regulation Series of white papers, and Minnesota Public Utilities Commissioner Nancy Lange serves on the series' advisory group).⁴⁹

- c. **Issue a guidance document on distribution planning in 2017.** This guidance document will not necessarily be a commitment to rule-making or other formal action, but should be helpful in clarifying Minnesota's grid modernization approach.

As an ongoing multi-interest learning and sharing platform, the e21 Initiative would like to continue supporting the Minnesota PUC's grid modernization efforts, and toward that end e21 proposes to

- a. identify opportunities in upcoming dockets to begin to address foundational and no-regrets actions
- b. take up issues that PUC technical workshops won't be well equipped to foster an on-going conversation about and feed the results back into the PUC process
- c. take up issues just beyond the PUC's current focus with the aim of offering definition and depth on topics likely to be next up for consideration (this will obviously require close coordination and communication with the PUC and regulatory staff)

⁴⁹ <https://emp.lbl.gov/future-electric-utility-regulation-series>

Appendix A: Principles for Modernizing the U.S. Electric Grid

As listed in the U.S. Department of Energy Quadrennial Energy Review, April 2015

1. **The future grid should encourage and enable energy efficiency and demand response to cost-effectively displace new and existing electric supply infrastructure, whether centralized or distributed.** The policies, financial tools, and pricing signals that enable customers to save money and energy while enhancing economic growth should be preserved and strengthened as business models evolve.
2. **The future grid should provide balanced support for both decentralized power sources and the central grid.** As the costs of decentralized power sources and storage continue to fall, there will be increased opportunities for end users to partially or completely supply their own electricity. At the same time, the vast majority of American homes and businesses will continue to rely on the power grid for some or all of their electricity. It is essential, then, that investment in both centralized and decentralized systems occur in a balanced manner, preserving high-quality service for all Americans while simultaneously enabling new options and services that may reduce energy costs or climate impacts. Similarly, access to renewable energy, energy efficiency improvements, and new energy-related services should not be limited to isolated customer groups, but rather become an integral part of the universal service that both decentralized and centralized grid customers enjoy.
3. **In the future grid, new business and regulatory models must respect the great regional diversity in power systems across the United States, as well as the critical roles played by state, local, tribal, and regional authorities, including state public service commissions and regional grid operators.** The drivers of change in the power system cut across the traditional boundaries of state and federal regulation and thereby introduce new challenges in designing and overseeing new business and regulatory models. An unprecedented amount of consultation and collaboration will be necessary to ensure that national objectives are met alongside complementary state policies in power systems that are inherently regional in their scope and technology.
4. **Planning for the future grid must recognize the importance of the transmission and distribution systems in linking central station generation—which will remain an essential part of the U.S. energy supply for many years to come—to electricity customers.** Transmission and generation both benefit from joint, coordinated planning. Transmission can allow distant generation—where there may be excess capacity—to supplement local supply and avoid the need to build new plants. New generation sometimes requires new transmission, especially remotely sited renewables or new nuclear plants. Utility and regional transmission organization planning processes and tools should continue to evolve to evaluate transmission, generation (both central and distributed), and demand-side resources holistically.
5. **Finally, the careful combination of markets, pricing, and regulation will undoubtedly be necessary in all business and regulatory models of the future grid.** While the precise nature and scope of the market structures in the future grid may vary considerably, there is little doubt that markets in one form or another will be an important means of providing access to new technologies and services. Even in settings where prices are regulated, novel approaches can allow beneficial new pricing and service structures.

Moreover, both new and traditional financing options provided by capital markets will be an important element in the future industry landscape.

Appendix B: The Federal Grid Modernization Multi-Year Program Plan

Grid Modernization Multi-Year Program Plan. In January 2016, the U.S. Department of Energy announced the release of its Grid Modernization Multi-Year Program Plan, a blueprint for modernizing the U.S. grid and solving the challenges of integrating conventional and renewable sources with energy storage and smart buildings, while ensuring the grid is resilient and secure to withstand growing cybersecurity and climate challenges. The plan aims to support critical research and development in advanced storage systems, clean energy integration, standards and test procedures, electric vehicles, solar systems, and a number of other key grid modernization areas. Available research and development funding will fall under the Grid Modernization Laboratory Consortium, which includes 14 Department of Energy labs and dozens of industry, academic, and state- and local-government partners across the country.⁵⁰ Expected outcomes of the effort include:

- a national network of laboratory facilities for use in testing and validation of emerging grid-related technologies and systems
- new common standards and test procedures to ensure that emerging grid technologies can communicate with one another and work together to provide energy services to customers
- new decision-support tools for integrated planning and operation of distributed energy technologies, such as solar, demand response, and smart consumer appliances
- advances in grid design and planning tools to take into account the increasing number of emerging technologies being deployed on the grid in homes, businesses, and communities
- optimal approaches for integration of wind turbines, solar photovoltaic systems, smart buildings, electric and fuel cell vehicles, and hydrogen technologies into a modernized grid
- a new testbed for development of advanced distribution management systems that will allow grid operators to more effectively utilize grid assets, increase resilience and reliability, and enable a wider choice of energy services for customers

⁵⁰ <http://energy.gov/articles/launch-grid-modernization-laboratory-consortium>