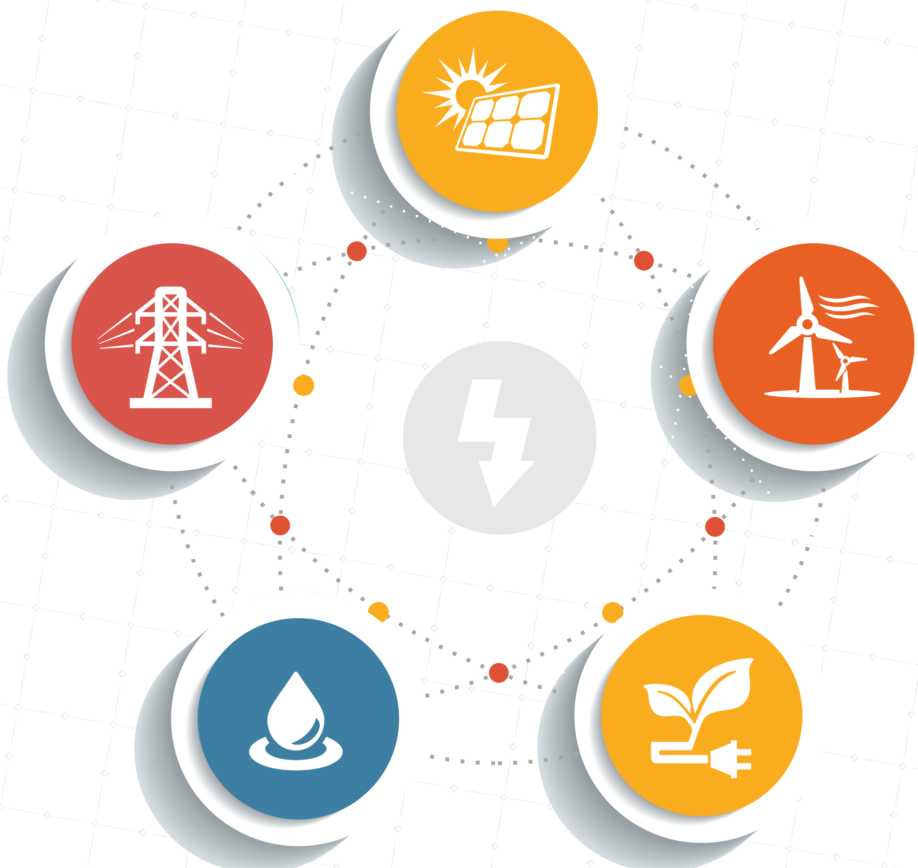
POWERING TOMORROW

PHASE 2 - FINAL REPORT



New Utility Industry Structures and Regulatory Packages in an Era of Increasing Energy Decentralization

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EXECUTIVE SUMMARY

This report describes the goals, process, and results of Phase 2 of the Powering Tomorrow project, and outlines the next steps to be taken. Powering Tomorrow is a collaborative effort originally organized by four former state utility commissioners (Kris Mayes, Arizona; Darrell Hanson, Iowa; Lauren Azar, Wisconsin and Scott Weiner, New Jersey). The project has been funded with contributions from members of a diverse Stakeholders Group. The Stakeholders Group also provided valuable information and feedback that helped inform Powering Tomorrow's work.

I. GOALS:

The overarching objective of the Powering Tomorrow Project is to define the industry structures and regulatory packages that will allow a smooth transition from the more unitary, centralized system of energy provision of today, to a more decentralized system involving a cast of numerous market participants, while simultaneously securing the vitality of the nation's utilities and a fair playing field for the new energy-market entrants. A detailed list of the project's First Principles can be found in section I of the report.

II. PHASE 2 PROCESS:

Phase 2 began with a series of conference calls between the Commissioners and the Stakeholders Group members to give the Commissioners an opportunity to learn more about the range of opinions and interests among the members. Face-to-face meetings were held in Newark, NJ in October, 2014 and in Tempe, AZ in March, 2015. A small number of consultants were retained to assist with the project and participated in these calls and meetings when appropriate.

Before developing the alternative regulatory options for the electric industry, we first needed to define the context in which those regulatory measures would be employed. The industry continues to change, with jurisdictions moving in somewhat different directions. Future regulatory contexts can be seen as differing along two dimensions: the general structure of the electric utility industry, and the business models of utilities operating within those industry structures.

Along the industry structure dimension, jurisdictions will be differentiated by the degree to which non-utility competitors and customers may plan, implement, own, or operate the infrastructure and services on the grid edge, which we define as anything on the customer's side of the meter. Using the input received from the Stakeholders and consultants, the Commissioners developed outlines of two alternative industry structures that could develop in the near future through a combination of political decisions and natural evolution of the industry, as well as a general description of an industry structure that might arise in the more distant future.[1]

Along the utility business model dimension, utilities will be differentiated by the degree to which they are vertically integrated or deregulated, and whether they operate inside or outside of a centralized energy market. We considered three different state and regional utility business models:

- Retail choice in centralized energy market[2] with utility distribution companies (UDCs);
- Vertically integrated electric utilities (VIEUs) in a centralized energy market;
- VIEUs located outside of a centralized energy market.

Examples of regulatory packages were constructed that might be appropriate for different combinations of potential industry structures and utility business models.

In addition, two single-issue frameworks were crafted to target issues relating to low-income customers and interstate transmission. A preliminary draft of this report was circulated to the Stakeholders Group and an Advisory Board for their comment and suggestions, which were taken into account in the drafting of the final Phase 2 report.

III. INDUSTRY STRUCTURES:

As described above, we first set out to define alternative structures of this changing industry that are differentiated by the degree to which non-utility competitors and customers may plan, implement, own, or operate the infrastructure and services on the grid edge, which we define as anything on the customer's side of the meter. We defined the following two potential future industry structures:

Industry Structure 1: Competition on the Grid Edge ("Competitive Structure") The Competitive Structure assumes transformational changes on the distribution grid, but it also assumes that the distribution grid will continue to exist for the foreseeable future and utilities will continue to own and operate the basic distribution system (BDS). The BDS includes infrastructure from (and including) the distribution substation up to the customer's meter and basic meters including advanced metering infrastructure. In limited circumstances it could also include microgrids, community renewable energy connected to the BDS but not located on customer premises, or storage not located on customer

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[1] [1] These two alternative industry structures and the accompanying regulatory packages are meant to be examples of possible outcomes rather than recommendations or predictions of what will necessarily occur.

[2] A centralized energy market would include Regional Transmission Organizations (RTO's) and Independent System Operators (ISO's).

premises. Also, the Public Utility Commission (PUC) would facilitate an in-depth and transparent BDS planning process; implementation of those plans would involve an RFP process with the constructed assets being rate-based by the utilities.

For the most part, the grid edge would be open territory for competition among non-utility entities. Competitors, individual customers and utility affiliates would be permitted to sell, install, own, or operate any component located on customer premises as well as advanced meters requested by customers and approved by the PUC). In most circumstances the competitive world of the grid edge would include microgrids and community renewable energy. In some circumstances it could also include storage connected to the BDS but not located on customer premises.

Industry Structure 2: Utility Partnerships and Ownership on the Grid Edge ("Partnership Structure") The Partnership Structure takes the industry structure of today as it currently exists, and envisions a series of incremental changes being adopted by utilities and states designed to advance state energy goals as they evolve over time. Compared to structure 1, utilities would have a greater ability to own and operate components on the Grid Edge, and more responsibility to plan and implement BDS improvements. States would implement desired regulatory changes in a more graduated and less comprehensive fashion. We assume that the grid edge will develop and diversify under both industry structures, but we do not envision the grid edge developing as rapidly under structure 2.

IV. EXAMPLES OF REGULATORY APPROACHES:

Section V.B of the report outlines regulatory packages consisting of combinations of these industry structures and ratemaking options. These are merely examples of packages that would be appropriate for each industry structure. All of the ratemaking options could be used in either structure. Section V.C suggests some regulatory options that might be appropriate in the long-term future. Figure 1 below indicates the pages of this report that deal specifically with each combination of industry structure and utility business model, as well as possible approaches in the long-term future. Those packages are summarized following Figure 1, and a more detailed description of each package is presented in the report.

		Near-Term Industry Structure		Long-Term Future
		1. Competitive Structure	2. Partnership Structure	
Utility Business Model	VIEU in Centralized Energy Market	pp. 4-5; pp. 15-24; pp. 28-29	pp. 4-5; pp. 24-26; pp. 31-32	p. 6; pp. 32-33
	UDC	pp. 5; pp. 15-24 pp. 29-31	pp. 5-6; pp. 24-26; pp. 32	
	VIEU Outside of Centralized Energy Market	pp. 4-5; pp. 15-24; pp. 28-29	pp. 4-5; pp. 24-26; pp. 31-33	

Figure 1

Vertically Integrated Utilities in the Competitive Structure (industry structure 1): With some exceptions, utilities would be prohibited from competing on the grid edge in the Competitive Structure. As a result, VIEU revenues and net cash flows in structure 1 will likely be lower than in structure 2, all else being equal. For example, increasing deployment of distributed generation and energy efficiency improvements will create a challenge for utilities whose revenues depend on energy sales. Accordingly, the regulatory packages for industry structure 1 must be more responsive than structure 2 to declining VIEU revenues and ratebase where adding to ratebase would increase investor value.[3]

An appropriate regulatory approach for VIEUs in the Competitive Structure could establish a multiyear rate plan covering four or more years to cushion the utility from falling revenues, combined with an indexed attrition relief mechanism to protect the utility from losses due to unexpected economic downturns.[4] Since the utility's estimates of future costs and revenues would be used to help design the multiyear rate plan, an

[3] A growing ratebase benefits investors only if the utility earns returns on capital that exceed the cost of capital. See Myron Gordon, *The Cost of Capital to a Public Utility*, Michigan State University Press (1974).

[4] Multi-year rate plans, attrition relief mechanisms, and other ratemaking tools are described in the body of the report and defined in greater detail in Appendix A.

earnings-sharing mechanism would allow ratepayers to share any unexpected surpluses, thus reducing the gains to the utility associated with any given over-estimate of costs or a given underestimate of revenues. The rate plan would include a system of rewards and penalties to provide the utility with incentives to address system maintenance, meet reliability targets, and achieve other important goals as determined by the PUC.

Utility Distribution Companies in the Competitive Structure (industry structure 1): UDCs are already prohibited from owning generation, and presumably they would also be prohibited from owning large-scale storage that could be bid into the market like a generator. Unlike the VIEUs, therefore, the UDCs' revenue streams under industry structure 1 would be relatively unchanged from the today's *status quo*. The primary revenue challenge for UDCs would the same as it is today, namely the loss of load from energy efficiency and distributed generation, and demand response efforts.

An appropriate regulatory approach for UDCs would also include multiyear rate plans with performance incentives as described above, but with the addition of "adaptive decoupling" to reduce the utility's incentive to maximize energy sales. Under this decoupling approach, any revenue shortfall or overage during the plan period is reconciled by raising or lowering the customer charge. For example, if enough customers install distributed generation to cause the utility's revenue to fall below the level where the utility has enough resources to maintain the system and earn a reasonable return, the customer charge would increase to restore adequate revenue. This would also prevent the utility from using unreasonably high customer charges as a tactic to discourage customers from installing their own generation, because the customer charge would only be increased when necessary.

Vertically Integrated Utilities in the Partnership Structure (industry structure 2): Industry structure 2 represents a more traditional approach. Accordingly, so will the attendant ratemaking. General rate cases based on cost of service will continue at current intervals but will use forward-looking test years. Cost trackers will be used for fuel, purchased power costs and changes in policy that cause large unpredictable costs. Traditional decoupling will be applied based on a revenue-per-customer approach to reduce the utility's incentive to increase earned returns. As with the other regulatory packages, award/penalty mechanisms will be used to align utility incentives with customer interest and public policy priorities. As with the package for VIEUs in industry structure 1, this package includes an earnings-sharing mechanism. However, in this case the earnings-sharing mechanism would be designed to promote operational efficiency and partnerships with third-party vendors, by allowing the utility shareholders to retain a portion of any cost savings.

Utility Distribution Companies in the Partnership Structure (industry structure 2): Under both industry structures, UDCs are prohibited from participating in grid edge endeavors such as distributed generation, community renewable energy, and large-scale storage. The major difference in terms of UDC revenue is that they are free to develop microgrids under structure 2. Since this is not a sufficient difference to warrant a separate regulatory package, the regulatory package for UDCs under industry structure 1 would also be suitable for structure 2.

Regulatory Package for the Long-Term Future: The previous regulatory packages are based on the assumption that there will be no radical departures from the status quo in the near term. Long-term changes could be much more dramatic. Many of the functions currently performed by utilities could be opened to competitive markets. This would expose utilities to the same type of competitive pressures that railroads and telecom utilities have faced, and generate many of the same types of issues. For example, a competitive market for distributed generation would raise utility concerns about stranded assets and "cream skimming" by private competitors, who in turn would be concerned about utilities cross-subsidizing affiliates and using non-economic pricing to stifle competition.

Traditional cost-of-service regulation is incompatible with competitive entry into the utility's market. An approach that would make sense in this hypothetical scenario would be similar to the systems used to regulate incumbent local telecom exchange carriers. Possible components of such a system are discussed beginning on page 30 of this report.

V. STAND-ALONE ISSUES:

The former Commissioners and stakeholders of this Project agreed that it would be beneficial to separately address two distinct areas – the provision of electric service to low income customers, and transmission policy in a time of energy transition – because of their importance and unique characteristics. The low-income framework attempts to assist policymakers in ensuring that the technologies associated with decentralization remain available to all income segments, while also ensuring that low income customers are not burdened by rate changes associated with the energy transition. The transmission framework is aimed at streamlining the siting of multi-state transmission lines, as certain regions of the nation continue to build out their renewable energy potential and seek to access clean energy from remoter areas. Both of these subjects will remain important regardless of the industry structure that exists.

VI. DISCLAIMER:

The results of the Powering Tomorrow Project identified in this report, including the industry structures and associated regulatory packages, are the work of the four former Commissioners who led this effort, Lauren Azar, Darrell Hanson, Kris Mayes and Scott Weiner.[5] [6] This report and the options contained in it were drafted with the valuable

[5] Lauren Azar served as a member of the Wisconsin Public Service Commission from 2007 to 2011; Darrell Hanson served on the Iowa Utilities Board from 2007 to 2013; Kris Mayes served on the Arizona Corporation Commission from 2003 to 2010 and was its Chairman from 2009-2010; and Scott Weiner served as President of the New Jersey Board of Public Utilities from 1990 to 1991. The former Commissioners serving on Powering Tomorrow were evenly divided politically – two Republicans, and two Democrats.

input of the following companies: Duke Energy, General Electric, NRG, PG&E, PSEG, Sun Edison and Xcel Energy (the Stakeholders Group). However, these companies do not necessarily endorse any particular industry structure or regulatory package designed as part of this Project. Indeed, given the difficulty of the topic, even the Commissioners could not reach consensus on some issues. As a result, some of the components of this report represent majority decisions rather than unanimous endorsements.

CONTACT INFORMATION:

For questions or comments, please contact Kris Mayes at kris.mayes@asu.edu or Darrell Hanson at darrellhanson2@gmail.com.

[6] Former Commissioner Lauren Azar participated in Powering Tomorrow from its beginning up through July 2015. She helped to prepare the initial draft of this Phase 2 – Final Report that was released to stakeholders in July. Lauren left this initiative to work on another project addressing some of the same issues as Powering Tomorrow; she could not participate in both. Former Commissioner Scott Weiner worked on the Powering Tomorrow Project in 2014 and for the first two months of 2015. However, after he become heavily involved with New York's Reforming the Energy Vision (REV) initiative that deals with similar issues, Scott stepped down from the Powering Tomorrow executive team. He remains involved in Powering Tomorrow as a member of the Advisory Group.

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I. INITIATIVE GOALS

In recent years it has become increasingly clear that America's energy sources are becoming more diverse, leading to a growing focus on how best to facilitate a smooth transition from the more unitary, centralized system of energy provision of today, to what would appear to be a more decentralized system involving a cast of numerous market participants. The overarching objective of the Powering Tomorrow Project is to define the industry structures and regulatory packages[7] that will allow regulators and other policymakers to make this transition, while simultaneously securing the vitality of the nation's utilities and a fair playing field for the new energy market entrants. More specifically, the Powering Tomorrow Project aims to:

1. Ensure U.S. electricity consumers have a **safe and reliable source of electricity at a reasonable cost**. The historic criteria that has been used to evaluate whether an electric utility has met these obligations has become outdated. Technology, economics and other aspects of the electric industry have and continue to change and so too must our tools to ensure utilities are responsive to this changing environment. For example, "safe and reliable" must now accommodate the new physical (including extreme weather) and cyber challenges.
2. Allow **investor-owned public utilities to adopt long-term sustainable business models** (or if in a holding company structure, the parent corporation) while also assuring financial stability during any transition to new regulatory and/or business models; all to the end that the utility is afforded a reasonable opportunity to earn a fair return and the utility or a related enterprise is able to attract capital by adequately rewarding investors;
3. Allow a **fair opportunity for new technologies and providers** to enter and compete in the market through the recognition of the value provided to the grid, customers and society at large while also assuring that customers and enterprises deploying the technologies pay an equitable share of costs associated with their net impact to the grid. In addition to traditional electric infrastructure, the technologies that must be accommodated will include, but not be limited to, the following
    - storage
    - distributed generation
    - load shifting through customer initiatives including demand response and other forms of responsive load
    - microgrids
    - electric vehicles
    - load reduction including energy efficiency
    - combined heat and power

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[7] The Powering Tomorrow executive team initially began this Project using "Frameworks" to describe a combination of industry structures and new regulatory models, but moved eventually into separating the industry structures from the ratemaking models.

- transmission development that addresses regional and interregional needs
- technologies that increase efficient use of existing assets, e.g. reducing losses, and
- flexible reserves for integration of variable energy resources such as wind and solar.

4. Ensure the building of **electric infrastructure and the efficient operation of the electric industry** that is necessary for our nation's prosperity. Historically, the state incentivized utilities to build new infrastructure through the return on equity for rate-based assets. In the new energy economy, removing market barriers may be sufficient to prompt investment in new infrastructure. However, given the importance of new infrastructure, all options must provide a mechanism that ensures building infrastructure that is necessary for the nation's economy.
5. Promote achievement of environmental goals, laws and regulations.

After identifying potential industry structures and an associated menu of generic regulatory options, the Project will then take a state-by-state approach in a subsequent phase to tailor the menu to state-specific needs. The former Commissioners will not advocate for a particular solution, but instead, will offer the menu to state legislatures and state commissions and encourage them to choose which options are best suited for their needs.

In addition to assisting states in addressing the ongoing energy transformation, we hope that the Powering Tomorrow regulatory options will be helpful to states as they craft their compliance plans for the Clean Power Plan, the EPA's carbon reduction requirements being promulgated pursuant to Rule 111(d) of the Clean Air Act.[8]

II. PROCESS USED IN PHASE 2

Beginning in July, 2014, the former Commissioners began preparing for Phase 2 by holding a series of conference calls with the Stakeholders Group. The purpose of these calls was to learn more about the range of opinions and interests among the members and to make sure each participant was comfortable with the First Principles of the Powering Tomorrow initiative. During this period the effort to recruit additional stakeholders continued, with the goal of securing sufficient funding for Phase 2 while including the broadest possible spectrum of viewpoints among the stakeholders.

[8] In August 2015, the EPA released its final rule under Rule 111(d) of the Clean Air Act, known as the Clean Power Plan. According to the rule, states will have until September 2016 to develop State Implementation Plans (SIP) detailing how they will bring their carbon emissions down to the established goals set for that state. The states have a wide variety of options for meeting these goals., including additional renewable energy, distributed generation, energy efficiency and demand response. The former Commissioners believe that the regulatory options outlined in this report could support a given state's SIP, and at the very least, would assist states in implementing their SIPs.

Newark Meeting, Oct. 12-13, 2014

Phase 2 of the Powering Tomorrow initiative was formally launched on September 5, 2014. Telephone discussions continued with the Stakeholders Group while preparations were made for the first face-to-face meeting to be held October 12-13 in Newark, New Jersey.

The group that assembled in Newark on October 12 included the four former Commissioners, consultants Steve Kihm of the Energy Center of Wisconsin and Robert Gurman of Pocono Manor Investors, and representatives of the following stakeholder companies:

- Duke Energy
- GE
- NRG Energy
- PG&E
- PSEG
- SunEdison
- Xcel Energy

During two days of lively discussion the members of the Stakeholders Group expressed their views on fundamental questions facing the electric utility sector and presented their visions for the future. As expected, there was disagreement among the group members about the ideal direction that should be taken by the industry and regulators. However, the goal of this meeting, and of Phase 2 as a whole, was not to achieve unanimity among the Stakeholders and former Commissioners. The goal of the meeting was to gain a richer understanding of each other's perspectives so that the former Commissioners' eventual decisions would be informed by the expertise and experience of the Stakeholders.

Framework Drafts & Committee Meetings

After the October meeting, the former Commissioners used what they had learned in Newark to help them draft alternative comprehensive regulatory frameworks and single-issue frameworks to be discussed with the Stakeholders at a second face-to-face meeting in Tempe, Arizona in early 2015. Initially, two comprehensive frameworks were drafted:

- **The Robust Distribution System:** utilities retain monopoly control of the basic distribution system, but the customer-facing edge of that system would be opened to competition; performance incentives would be added to cost-of-service ratemaking)

- **The Utility as Primary Resource Orchestrator:** utilities serve as primary orchestrator and integrator of emerging technologies, using grid services provided to the utility by third-party companies, and allowing competitive markets for services to customers at the edge of the distribution system accompanied by an advanced performance-based regulatory approach. This framework was ultimately replaced by the third approach described below.

Three single-issue frameworks were also drafted:

- **Low Income Customers: see page 34**
- **Multi-state Transmission: see page 37**
- **Energy Efficiency**

The framework drafts were shared with the Stakeholders Group. Committees were formed to discuss the drafts during conference calls and suggest revisions, and Stakeholders Group members were asked to serve on one or more of those committees.

During the committee process it became evident that there was interest in developing an alternative that is based on less significant changes in utilities' current business models. With the assistance of consultant Mark Lowry of Pacific Economics Research Group, the former Commissioners developed a third comprehensive framework in which incremental changes to utility operations would be encouraged through ratemaking changes that realigned utilities' incentives consistent with Powering Tomorrow's First Principles.

Stakeholder feedback indicated little support for further development of a single-issue energy efficiency regulatory framework, primarily because there has already been significant work done on that front. Accordingly, the energy efficiency framework was eliminated from further discussion.

Tempe Meeting, March 16-17, 2015

The second face-to-face meeting was held in Tempe, Arizona on March 16-17 to discuss the framework and single-issue drafts. In addition to the Commissioners[9] and consultants Steve Kihm and Mark Lowry, the following stakeholder companies[10] were represented at the meeting:

- GE

[9] Former Commissioner Scott Weiner did not participate in this meeting.

[10] Duke Energy and PG&E ended their participation in the Powering Tomorrow project prior to this meeting.

- NRG Energy
- PSEG
- SunEdison
- Xcel Energy

During this meeting it became clear that there was little interest in pursuing the framework that envisioned the utilities becoming the primary orchestrator of services provided by third-party companies in competitive markets. It was seen as somewhat similar to the current REV proceeding in New York, and the group agreed that Powering Tomorrow should focus its resources on the other proposed frameworks.

As a result of the input received at the Tempe meeting as well as the committee discussions, the executive team decided to separate the system-wide issues into two categories:

- Structure of the electric utility industry in a jurisdiction (such as which markets are open to competition and the utilities' ability to participate in activities on the edge of the distribution system).
- Ratemaking options in the jurisdiction (including incentives and penalties, cost-of-service, multi-year rate plans etc.)

The industry structure options are independent from the ratemaking options; jurisdictions can choose from among the options in each category and mix them as they see fit.

Based on the feedback received from Stakeholders, the executive team chose to fully develop the following proposals:

- Industry Structure 1: Competition on the Grid Edge
- Industry Structure 2: Utility Partnerships and Ownership on the Grid Edge
- Example Regulatory Packages for Industry Structure 1
- Example Regulatory Packages for Industry Structure 2
- Example Regulatory Package for the Long-Term Future
- Low Income Customers (single-issue framework)
- Interstate Transmission (single-issue framework)

The executive team then solicited additional review and feedback from several sources before finalizing this report. Those sources included the Stakeholders Group, the Advisory Committee[11], Steve Kihm, Mark Lowry and an additional consultant, Doug

[11] The Advisory Committee is made up of representatives of industry and non-governmental organizations, consumer advocates and former commissioners.

Scott of the Great Plains Institute.[12] After considering the input from these sources and making changes that seem warranted, the executive committee finalized this Phase 2 Report.

III. SPECIFIC GOALS FOR THE OPTIONS PRESENTED IN THIS REPORT

Historically, utilities were the sole provider of electric service and, as new technologies were developed, they were generally implemented by the utility in its role as sole provider of energy services. However, new technologies, public policy, and changing customer preferences and expectations are challenging the model of utility as sole provider. Indeed, emerging technologies are pulling the industry in directions that were unimaginable just ten years ago.

To develop the appropriate regulatory options for the electric industry, we must first define the structure of this changing industry. In this paper, we provide two industry structures that address such questions as the following:

- Who owns what infrastructure?
- Who operates what infrastructure?
- Who is responsible for planning for new infrastructure to ensure electricity customers have a safe and reliable source of electricity at a reasonable cost?
- Who is responsible for implementing those plans?
- Are there any restrictions on utilities and their affiliates?
- Are there any restrictions on non-utilities' participation in the electric industry?

After describing the two industry structures, the paper then attends to the ratemaking options that would be appropriate for those structures.

Because the electric industry differs on a state and regional level (and sometimes on a utility level), it is difficult to craft recommendations that work seamlessly with all models. This paper addresses the most common state and regional models, which are as follows:

- retail choice in centralized energy market with utility distribution companies (UDCs),
- vertically Integrated Electric Utilities (VIEUs) in a centralized energy market, and
- VIEUs located outside of a centralized energy market.

[12] Doug Scott is the former Chair of the Illinois Commerce Commission and currently works on regulatory issues affecting a variety of states.

There are, of course other models that can be addressed on a case-by-case basis.

IV. INDUSTRY STRUCTURES

A. INDUSTRY STRUCTURE 1: Competition on the Grid Edge (“Competitive Structure”)

The role of the electric industry in structure 1 will not change from the current industry structure as it relates to central station generation and the bulk electric system. While structure 1 assumes transformational changes in the industry will occur on the distribution grid, it also assumes that the distribution grid will continue to exist for the foreseeable future and utilities will continue to own and operate that grid.

1. Central station generation: Utility involvement in centrally located generation will remain at the discretion of state policymakers. VIEU’s will be expected to demonstrate the cost-effectiveness of any proposed new generation or power-purchase agreements.

2. Transmission: Utility involvement in transmission will remain at the discretion of state policymakers. However, the role of merchant owners and non-incumbent utilities is expected to increase due to the effects of Order 1000.[13]

3. Distribution: Structure 1 is designed around our legacy distribution infrastructure and emerging distributed energy technologies. For purposes of this whitepaper, the distribution system is separated into the following two categories:

a. The basic distribution system (BDS) that includes the following components:
   1) The electric and information technology (IT) infrastructure from (and including) the distribution substation up to the customer’s meter,
   2) Basic customer meters that could include advance metering infrastructure (AMI) (not enhanced customer meters which could be requested by the customer),
   3) In limited circumstances, microgrids,

[13] FERC’s Order 1000, issued in 2011, requires large-scale regional planning of the nation’s electric grid. One of the goals of Order 1000 is to encourage transmission development that opens the way to greater access to renewable energy.

4) In limited circumstances, renewable energy connected to the BDS but not located on customer premises ("Community Renewable Energy" or CRE), and
5) In some circumstances, storage connected to the BDS but not located on customer premises.

b. Edge of the Grid (Grid Edge) that includes the following components:
   1) Enhanced customer meters that are requested by the customer and approved by the public utility commission (PUC),
   2) Anything located on the customer's premises,
   3) In most circumstances microgrids,
   4) In most circumstances CRE, and
   5) In some circumstances storage connected to the BDS but not located on customer premises.

The existing distribution system and the likely continued use of that distribution system for at least the foreseeable future constitutes a natural monopoly, i.e. an industry where it is most efficient to have one supplier. Accordingly, the incumbent utility will remain the owner and operator of the BDS. In areas where the incumbent utility is a VIEU, the VIEU will be the BDS utility and, in retail choice areas, the UDC will be the BDS utility.

The largest change from the current BDS arises from how that system will be planned and new infrastructure constructed. Currently, the incumbent utilities alone decide what infrastructure is necessary and they propose changes to regulators. The utilities often hold all of the vital information concerning the existing BDS infrastructure and needs for improvement. This asymmetry of knowledge often results in the PUCs' inability to appropriately evaluate the needs and to consider alternative solutions.

Emerging technologies increasingly are providing the means to reduce losses and increase the efficiency of the BDS. While the regulatory options presented later in this paper attempt to align utility and the public's interests, such alignment may never be perfect. Accordingly, structure 1, increases the transparency of BDS planning, increases the robustness of BDS planning, and opens the implementation of those plans to competitive grid edge solutions.

4. BDS Planning: The utility's BDS planning would be transparent and open to competitive solutions: it would involve the utility, commission staff, and third-party stakeholders. Ultimately, the PUC would have final decision-making authority over the BDS Plans. To ensure that the PUC would have meaningful input into the process, the

PUC staff must have expertise in distribution planning, which would likely include training of existing staff or hiring of new staff or consultants.

BDS planning—state of the art integrated distribution planning—would include such things as:

a. Identifying aging infrastructure, including what infrastructure must be replaced within the next 5 years. (Through identifying aging infrastructure, the parties may be able to focus the planning efforts on those areas where rebuilding would be required anyway.)
b. Identifying where the distribution system is nearing its capacity and where it has excess capacity that would not be used in the foreseeable future.
c. Identifying areas where either shifting of load to reduce peak-demand or a reduction in load would obviate the need for upgrades; load shifting calculations would include, among other things, a cost-benefit analysis of storage.
d. Increasing the efficiency of the delivery system (with such things as volt-var controls and power controls).
e. Improving the performance of the delivery system (with such things as conservation voltage reduction).
f. Installing technologies that detect, localize and remedy load shedding;
g. Facilitating the installation of distributed generation (DG). (While DG is not part of the BDS, the utility has influence over how quickly and efficiently some DG can be installed.)
h. Facilitating usage of combined heat and power (CHP).
i. Predicting the locations and amounts of the following:
    1) heavy DG penetrations,
    2) demand response (DR) including aggregators,
    3) energy efficiency (EE), and
    4) electric vehicle (EV) charging stations and EV penetration (in urban areas).

While all of these components are on the Grid Edge, they must be considered when planning the BDS:

a. Developing Microgrids: as explained later, third parties would be the primary developer of microgrids. The BDS utility would need to include them in the BDS planning process. In limited circumstances, the BDS utility could propose microgrids with a narrow purpose, such as transportation systems.
b. Developing Community Renewable Energy – as explained later, third parties would largely develop CRE. Third-party proposals would need to

be included within the BDS planning process. The BDS utility, however, could propose small-scale CRE connected to the BDS for the sole purposes of solving a problem on the BDS, such as bolstering a feeder.

c. Developing IT systems that would, among other things, facilitate the installation of new behind-the-meter technologies.
d. Hardening of Infrastructure – identification of substations and other critical BDS infrastructure that are vulnerable to extreme weather events or other security threats.
e. Improving the efficiency of any load controlled by the BDS utility, such as public lighting.

Given the in-depth nature of these planning initiatives, full-scale BDS plans would be completed at least every five years and would cover a 20-year horizon. This long-term view would encourage planning and implementation of large-scale transformational improvements. Motions to re-open BDS plans would be required for unforeseen events, and could be filed by the utility, PUC, consumer advocates, and other intervenors. Outside of the formal planning process, third parties may propose to construct CRE, storage, or microgrids independently, which would be dealt with by the utility with oversight by the PUC.

Any improvements identified through this robust planning process would be *prima facia* prudent and the only issue for the PUC would be the reasonableness of the actual costs incurred. We are currently witnessing a drop in cost of many technologies, which would be considered by the PUC during its prudency review.

Utilities would propose solutions to needs within the BDS and utilities should be indifferent to whether those solutions are located on the BDS or the Grid Edge. To accomplish this, if the utility proposes a solution in an area where a market already exists – and therefore the utility is prohibited from implementing that solution – the utility should be financially rewarded if that solution is selected for implementation.

5. Implementation of the BDS Plans: Once the BDS Plan is developed, there are three options for choosing how the new infrastructure would be built. States would select which of the following they would prefer, or potentially apply different models for different types of infrastructure. Options include the following:

a. <u>Traditional Model</u>: The utility selects and hires the vendors for BDS improvements. The utility owns and operates those BDS assets and the costs are rate-based. The PUC conducts a prudency analysis on the costs.

b. Competitive Procurement Model: The BDS Plan would specify a standard or task to be met. The utility would develop and announce a proposal to meet that standard or task along with the proposed cost.

1) Independent Administrator Process: Third-party vendors would have the opportunity to propose a different (or the same) proposal and, if the cost is lower and the proposal meets the standard or task--as determined by an independent administrator[14]-- then the third party would be selected to construct that component of the BDS but would be required to sell it to the utility, at which time the costs would be rate-based.

2) Commission Process: The PUC (or its designee) would conduct a competitive bidding process for meeting that standard or task; the request for proposal would specify that the new BDS infrastructure would ultimately be owned by the utility. The utility and third parties could submit bids to the PUC. The PUC would select a winner. The utility would pay for and ratebase these improvements to the BDS. This would require Commissions to develop expertise and capacity to make well-informed decisions.

6. The Edge of the BDS: While the BDS would remain the protected domain of the incumbent utilities, the Grid Edge would be open to competition. Because there is already a market on the Edge, the incumbent utility (a monopoly) would be prohibited-- with three exceptions-- from competing on the Grid Edge. This is because utilities, with access to ratepayer-backed low-cost capital and other advantages, could dampen the competitiveness of the market. In sum, behind-the-meter infrastructure would not be owned and operated by the utility and, therefore, could *not* be ratebased – these services would be open to competition.

However, affiliates of utilities would be able to compete on the Grid Edge thereby allowing the parent corporation of the utility to develop new revenue streams. To ensure that the affiliates are not improperly advantaged in this market, safeguards must be created to ensure those affiliates do not coordinate with VIEUs. Specifically, the utility must treat its affiliates the same as third parties, which would include the following:

a. providing equal access to customer information,
b. providing non-preferential treatment for such things as interconnections and billing,

[14] Depending on the jurisdiction, independent administrators could be established by legislation or PUC order.

c. prohibiting advertisement of the relationship between the utility and its affiliates,[15] and
d. prohibiting cross-subsidies for its affiliates (such as shared joint and common costs).

While utilities may not compete on the Grid Edge, they would be allowed to provide financing programs for Grid Edge infrastructure.

The three exceptions to the no-utilities-on-the-Edge rule are demand response (DR), energy efficiency (EE), and where there are no competitive alternatives for a specific service.[16] In these situations, the utility may participate on the Grid Edge. Of course, for DR and EE, the utility would be competing with the private sector. Third-party aggregators of DR are permitted under Industry Structure #1. The utility may also install technologies on customer premises to help the utilities operate the BDS.

As to energy efficiency on customer premises, research has established that setting energy efficiency targets is an effective way to reduce overall load. The entity obligated to meet those targets depends on jurisdiction:

- Non-retail choice states - compliance with the targets rests with the BDS utility as the load-serving entity and the provider of last resort.
- Retail choice states – compliance rests with the UDC.

EE conducted by the utility can be ratebased.

Meters and customer information create special challenges in the emerging electricity industry. The BDS utility would install and own the basic meters on customer premises. (Basic meters can include AMI enabled meters.) However, a customer, or its third-party agent, may install enhanced meters[17] on the customer premises at which time the customer (or a third party) would own the meter. The PUC must pre-approve all enhanced meters to ensure that they will appropriately interface with the utilities' infrastructure.

Many believe that the information technologies available today are sufficient for facilitating full deployment of DER, which includes DG, DR and EE. In order to have a

[15] While customers may want to know whether a provider is affiliated with the utility, allowing the affiliate to use the imprimatur of the utility would significantly undermine the competitive market.

[16] Upon request by the utility, the PUC would conduct a proceeding to determine if there are competitive alternatives.

[17] Enhanced meters refers to any meter that contains features that go beyond the meter offered by the utility.

robust market on the Grid Edge, customer data must be available to DER providers as follows:

a. Protocols must be established to ensure the data is provided in a standard format.
b. Once an open platform and protocols are developed, utilities must promptly adopt them.
c. Data must be of a specified quality and provided to DER providers in near real-time.
d. Aggregated customer data, i.e. data that does not reveal a specific customer's information, would be available to certified third parties.
e. Individual customer data would be subject to opt-in/opt-out provisions. States would determine the default option: whether a customer has to provide explicit permission for his or her data to be shared with a third party or whether the customer has to explicitly prohibit such action.
f. The utility would provide raw data to certified third parties for free. If the utility is required to manipulate the data, it may charge a fee to the certified third party.
g. Certified third parties must prove to the PUC that their cyber security protections are sufficient.

Under Industry Structure 1, non-utilities will be conducting significant activity on the Grid Edge. Because those actions interface with the utility at the meter, the utility must have confidence in the competence of DER providers. Accordingly, the PUC will establish a certification for individuals installing technologies or providing services on the Grid Edge that could impact a utility's infrastructure or services. Among other things, this certification would involve safety and security:

a. DER providers must coordinate with utilities to ensure that the providers' activities do not harm the utilities' infrastructure or services, e.g. voltage and frequency.[18]
b. DER providers must provide information to utilities when it is required by the utility for proper operation of the BDS.
c. Contracts between DER providers and their customers must contain consumer protections that would be defined by the PUC.

7. Components That May be Part of the BDS or the Grid Edge: Microgrids, community renewable energy, and storage may either be part of the BDS or the Grid Edge.

[18] This is not meant to imply curtailment, which is a different matter.

MICROGRIDS: For purposes of this paper, "microgrids" are defined to include either of the following:

- a number of contiguous retail customers with a single meter connection to the BDS that would allow the microgrid to separate and island from the BDS while continuing to operate on DER within the microgrid, or
- a single large retail customer who has sufficient DER to be self-sustainable and who has the ability to separate and island from the BDS.

A single small retail customer should also be allowed to separate and island from the BDS, but for purposes of this document they are not included within the definition of a "microgrid."

a. Ownership and Operation of Microgrids:

Where markets for microgrids develop, utilities would normally be prohibited from developing and owning microgrids but may petition the PUC for a variance in special circumstances such as public transportation systems. In addition, utility affiliates could own and operate microgrids under the same conditions as infrastructure on the Grid Edge. Utilities could also provide financing programs for microgrids.

b. Responsibilities of the Microgrid Owner and Operator:

The owner and operator of the microgrid would be responsible for the following:

- coordinating with the utility during separation and isolation events to ensure safety of the BDS infrastructure and utility employees,
- complying with any safety standards set by the PUC,
- sub-metering within the microgrid for the microgrid participants, and
- complying with microgrid standards as they are developed.

c. Microgrids – the Obligation to Serve and Resource Adequacy:

The utility's obligation to serve the microgrid would differ from its obligation to other retail customers. The PUC would develop varying levels of obligations for microgrid owners and operators, each with differing levels of charges.

For example, if a microgrid owner and operator assumed all responsibilities, including the obligation to serve and resource adequacy, and only used the connection to the BDS for economic purchases of energy, then the charge to the microgrid would be minimal.[19]

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[19] Regulators would need to consider whether the microgrid should help pay for any stranded assets that occur as a result of the creation of the microgrid.

However, if the utility maintains the responsibilities of either the obligation to serve and/or resource adequacy, then the charges to the microgrid would be higher.

In establishing the charges to the microgrid, the PUC must ensure that charges are not proposed to create a market barrier. Also, the societal benefits (such as reduced need for new utility-scale generation) must be considered in addition to technical benefits (black-start assistance) when setting the charges to the microgrid.

COMMUNITY RENEWABLE ENERGY: Community renewable energy (CRE) is a generator or collection of renewable energy generators between 1 and 10 MWs (states would select a specific threshold) that are attached to the distribution grid. In retail choice states, retail customers may buy into the CRE and obtain a discount on their bills. In non-retail choice states, the CRE provider sells to the utility and is paid the wholesale price of electricity.[20]

Where markets develop for CRE, the utility would be prohibited from developing CRE unless the CRE is identified during the BDS planning process and is used for bolstering the BDS at a specific location. Utilities' affiliates may develop and own CRE. Utilities may provide financing programs for CRE.

STORAGE: Storage interconnected to the BDS can be used for multiple purposes. On the one hand, regulators should encourage utilities' development of storage as a tool in bolstering the BDS and for peak-load shaving. On the other hand, larger storage units can be bid into the formal energy markets and are therefore, part of a market.

Utilities subject to retail choice are not allowed to own generation. Accordingly, these utilities would be allowed to install and operate only smaller storage units and would be prohibited from installing larger units that could be bid into the energy market.[21] The threshold size for a larger unit would be dictated by the requirements of the pertinent energy market. Their affiliates could, of course, install larger units and the utilities themselves could provide a financing program for larger units.

Utilities not subject to retail choice could own and install any size storage unit within the BDS.

8. Conclusion on Industry Structure 1: Structure 1 is intended to maintain the *status quo* for generation and transmission. As to the distribution system, structure 1 is intended to:

[20] In some jurisdictions a different approach to setting the price may be taken.
[21] One exception to this is that utilities may own storage that can act like a generator.

- bolster the planning of the BDS to allow for long-term transformational changes that are prompted by new technologies,
- protect the utility as the sole provider of the BDS,
- recognize that the Grid Edge is expanding with competitive alternatives and that allowing a monopoly to compete on the Grid Edge would undermine those emerging markets, and
- allow utility affiliates to compete on the Grid Edge to create new revenues for the utility parent corporation.

B. INDUSTRY STRUCTURE 2: Utility Partnerships and Ownership on the Grid Edge ("Partnership Structure")

Industry structure 2 takes the industry structure of today as it currently exists, and envisions a series of incremental changes being adopted by utilities and states designed to advance state energy goals as they evolve over time. This industry structure would be characterized by utilities having a greater ability to own and operate on the Grid Edge than they would under structure 1 and it assumes that states would implement desired regulatory changes in a more graduated, and less comprehensive, fashion. (The difference between structure 1 and structure 2 is most pronounced for VIEUs. There are minimal differences between these structures for UDCs.) New rate designs and incentives will be the primary means by which the transition is accomplished, as regulators choose from a series of options that would encourage utilities to implement new energy services and engage in an increasing number of partnerships with third parties.

1. Differentiation from Industry Structure 1: In particular, structure 2 would differ in the following ways from Structure 1:

- Competition in the provision of DG services and miscellaneous other energy services is an important policy goal. For this reason, restrictions may be placed on utility involvement in DG on the Grid Edge. However, VIEUs will be permitted to invest in DG where doing so has been determined to be in the public interest. Partnerships between utilities and third-party energy providers will be encouraged for activities occurring on the Grid Edge.
- Utilities will be free to develop community renewable energy, microgrids, storage and facilities needed to accommodate DER penetration e.g. smart inverters. These developments may provide the basis for reliability-differentiated services. Such services will provide an option for customers with special requirements to pay for higher levels of reliability if that is important to them. An example of this would be a university that desired to add reliability protections in the distribution system on campus that would

bolster reliability and protect sensitive research, or that wanted to partner with a utility in the creation of a microgrid on campus.

- Customer data will be the subject of intense interest and debate, as distributed technologies continue to proliferate and as third parties seek to optimize customer data with new offerings. Under Structure 2, customer data will remain with the utility, though regulators will encourage the sharing of this data among utilities, their customers, and their designees, through rate designs and incentives.
- Unlike structure 1, under structure 2 utilities primarily will continue to determine which and under what timeframe, BDS improvements will be made. Some states may experiment with integrated BDS planning processes that include all stakeholders, but for the most part, this function will lie with the utility under structure 2.
- Unlike structure 1, third-party DR aggregators will be prohibited. Only the utility will be allowed to aggregate its customers in demand-side management programs.
- Because more DER is anticipated under the Competitive Structure, it is likely that more transmission will be required under the Partnership Structure.

2. Similarities with Industry Structure 1: Structure 2 would likely remain the same as Industry Structure 1 in the following respects:

- Utility-scale Generation: Utility involvement in centrally located generation will remain at the discretion of state policymakers. VIEU's will be expected to demonstrate the cost-effectiveness of any proposed new generation or power-purchase agreements.
- Transmission: For the most part, as in structure 1, the transmission system will continue to be owned by utilities and in some cases merchant providers. FERC Order 1000 will be implemented, likely fostering additional interstate transmission, and over time, the transmission system will evolve.
- The Basic Distribution System (BDS): The ownership and operation of the BDS under structure 2 will look very similar to structure 1. In most states, the provider of last resort will continue to operate the core functions of the BDS. Utilities will maintain their position as a natural monopoly under structure 2.
- The Grid Edge: As mentioned above, we do not envision the Grid Edge developing as rapidly under structure 2. VIEU ownership of some DG is allowed, along with partnerships between utilities and third party providers, to spur the evolution of the edge of the BDS.
- EE and DR: As with structure 1, utilities can participate in both EE and DR in structure 2. Utility involvement in EE programs will be at the discretion of

state policymakers. However, utilities will always have a major influence on DER through their control of rate designs.

3. Conclusion on Industry Structure 2: Where Structure 1 calls for greater competition on the Grid Edge, Structure 2 envisions that states and utilities will take a more gradual, incremental approach to change. In particular, it would facilitate a future in which utilities remain the operators and owners of the BDS, third-party energy providers continue to compete to provide services on the Grid Edge in those states that have determined that third-party providers can operate,[22] utilities are cautiously permitted to own and provide services on the Grid Edge, and utilities are encouraged to partner with third parties to build out the Grid Edge.

This industry structure would accomplish the following outcomes:

- The utility would have greater time to evolve its business models, by gaining experience owning and operating new energy services like DG, storage and microgrids.
- New energy entrants would be strengthened through a variety of facilitated partnerships with utilities, in such areas as residential and commercial solar, community storage and microgrids. Regulators will need to be cognizant of market structure issues, so that an appropriate level of competition is achieved.
- The BDS would maintain its vitality through the regulated ratemaking process and continued ownership by the utility.
- Consumers would continue to have options provided by both new market entrants,[23] and
- Change would be accomplished in the electricity sector, though over a longer timeframe and in a graduated fashion.

V. REGULATORY APPROACHES FOR ACHIEVING THE FIRST PRINCIPLES:

A. RATEMAKING: COST OF SERVICE VS. INCENTIVE REGULATION

Cost-of-service (COS) regulation has been the primary methodology used in the United States for setting utility revenues and electricity rates. Under COS, a PUC calculates a

[22] For example states such as Arizona and Iowa have explicitly declared that third-party leasing models for solar are allowed within utilities' service territories, while other states like Florida have declared the third-party ownership model off-limits.
[23] Subject to provisions in law in a given state. See footnote 12, supra.

utility's requirement for revenue based on the utility's operation and maintenance expenses, depreciation of capital assets and return on the rate base (net book value of assets). The PUC then allocates this revenue requirement to the various customer classes and utility services. The rates are established by predicting the amount of services that will be sold to each customer class.

Over the years, limitations to the COS have become apparent and, with the rise of DER, those limitations are amplified. The incentives embedded within a COS regime are not always aligned with the public good.[24] For example, COS can create perverse incentives for utilities, such as rewarding the building of capital assets when non-capital solutions--such as DER--would be more cost effective. Moreover, the utilities have become dissatisfied with the rigidity and regulatory lag that normally accompanies COS.

To address misaligned incentives and the rigidity of COS, several states and numerous countries have turned to incentive regulation as an alternative to COS. While incentive regulation can take many forms, the overall goal of incentive regulation is to align utility incentives with the public good, such as improving the efficiency of the utility and creating a market where competitive alternatives exist.

While COS and incentive regulation can be viewed as opposite ends of a continuum, rarely is either one applied in its pure form. Instead aspects of each are combined into a regulatory package that is customized for a jurisdiction's statutory authority, desired industry structure, and challenges such as increasing DG. For example, jurisdictions with a strong COS tradition could adopt a few performance incentives to address high priority concerns and to gain experience with the use of such incentives.

We have created example ratemaking options for the two industry structures defined above. Because industry structure 1 is less traditional than structure 2, the ratemaking options applied to structure 1 as set forth below are less traditional than structure 2. Specifically, a greater degree of incentive regulation is applied to industry structure 1 than 2. While incentive regulation is explained below, more expansive explanations can be found in Appendix A.

[24] As more and more electricity customers are looking for alternatives to traditional utility service, simply aligning the utility incentives with utility ratepayers' preferences may no longer be sufficient. Therefore, this paper seeks to align utility incentives with the "public good" rather than the ratepayer.

B. COMBINING INDUSTRY STRUCTURES WITH RATEMAKING OPTIONS:

Below we provide example combinations of industry structures and ratemaking options, which we call "regulatory packages." These are merely examples. All of the ratemaking options could apply to either industry structure.

1. Example Regulatory Packages for Industry Structure 1:

a. VIEU Example: Because utilities are prohibited from competing on the Grid Edge in industry structure 1,[25] we anticipate that utility revenues for VIEU's in structure 1 will be lower than in structure 2. Accordingly, for VIEUs, the regulatory packages for industry structure 1 must be more responsive to slow or declining revenues and ratebase than structure 2.

The flexibility of a multi-year rate plan (MRP) with an attrition relief mechanism (ARM)[26] is especially appealing for VIEUs who risk losing revenues from both DG and EE. A proper ARM will protect utilities from revenue losses caused by changes in the economy. Because the economy may be picking up steam but is still unpredictable, the ARM could be indexed.[27] The initial MRP will be a four-year MRP, with a mid-plan review and a new rate-case in the final year.

There will be two mechanisms for ensuring that the utility is accurately estimating its costs over the term of the MRP:

- The transparency of the BDS planning effort should encourage more accurate estimates.
- An earnings-sharing mechanism would be folded into the ratemaking mix. Specifically, the utility would be informed that, throughout the term of the MRP, if the utility's estimates for cost increases are overstated, the ratepayers would receive a larger percentage of the earnings sharing than the shareholders. The greater the discrepancy between estimate and reality, the more the ratepayers receive.

To ensure the utility appropriately addresses system maintenance and to promote efforts that reduce customer bills, targeted performance incentives (often called Award-Penalty Mechanisms or APMs) will be established for the following four metrics:

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[25] There are three exceptions to this prohibition: DR, EE, and where there are no competitive alternatives for a specific service.
[26] For more details on ARM, see Appendix A.
[27] An indexed ARM means that, within the term of the MRP, rates are automatically adjusted based on some index, such as the consumer price index.

- SAIFI, SAIDI and CAIDI
- Time-Sensitive Pricing in support of peak load shaving.
- Energy Efficiency Targets
- Reduction in losses. Each utility will be required to identify how they can reduce losses in their electricity system including generation, transmission and distribution.

Experience has demonstrated that tying executive compensation to the performance incentives is particularly effective.

Utility regulators with little or no previous experience with APMs may start by establishing performance metrics and incentives for a small number of high priority goals (or other goals selected by the regulator). Once a utility demonstrates success in these four metrics, the PUC may choose additional incentives in subsequent MRPs. Note that APMs are less important for controlling costs of capital and other base-rate inputs because MRPs themselves give utilities more incentive to contain these costs.

Cost trackers will be provided for fuel and purchased power costs and other large, unpredictable costs outside of the utility's control. The MRP would also have off-ramps, if significant changes occur, such as large changes in policy.

<u>b. UDC Example:</u> UDCs are currently prohibited from owning generation, which includes DG and CRE. Presumably, UDCs will also be prohibited from owning large storage that could be bid into the energy market like a generator. Unlike the VIEUs, then, the UDC's revenue streams under industry structure 1 are relatively unchanged from the today's *status quo*. The primary revenue challenge for UDCs today arises from the loss of load through DG and EE and the loss of peak load through DR. Accordingly, the regulatory package for UDCs in industry structure #1, must address those challenges.

A four or five-year MRP would also be applied to UDCs under structure 1. The plan would include "adaptive decoupling", to eliminate the utility's throughput incentive. Traditional revenue decoupling allows utilities to recover lost revenues through the use of surcharges or credits that are typically applied on a per kWh basis; this traditional approach can blunt the price signal to customers for energy efficiency.[28] Under adaptive decoupling, any revenue shortfall or overage is reconciled through the customer charge. In this way, if the utility loses a large

[28] The energy efficiency APM described below should help to increase EE regardless of the blunting of the price signal.

amount of sales load, it collects more fixed costs through the fixed charge. Conversely, if the loss of sales is less than expected or if sales actually grow, the fixed charge does not have to change very much or might even go down. By approaching recovery of lost revenues in this manner, the utility raises its fixed charge only if it needs to, and not as a preemptive strike against possible loss of sales. Adaptive decoupling also eliminates the ability of DER customers to bypass the decoupling mechanism.

The regulatory package for UDCs in structure 1 would also include performance incentives, including, but not limited to, the following:

- SAIFI and CAIDI – penalty only
- Time-Sensitive Pricing – reward and penalty
- Energy Efficiency Targets - reward and penalty
- Interconnection Times for DG – because the UDCs will be especially sensitive to DG penetration, an incentive mechanism is warranted here. This would be award and penalty.

c. For jurisdictions already using MRPs: Regulators with MRP experience who wish to move into advanced MRPs might consider the following innovations:

- Longer plan terms (e.g., 5-8 years)
- New approaches to the design of MRPs, such as incentive-compatible menus where a utility would select one option from a menu of combinations of incentive plan provisions designed so that the utility's choice would reveal its expectation of future costs. For example, when regulators establish the annual revenue growth for an MRP, they often use the following formula:

  growth Revenue = Inflation – X + growth Customers

  where X could represent any factors that would lower the revenue growth (such as technological change or increased efficiencies in utility management). If an earnings sharing mechanism is applied to X, a utility with confidence in its ability to significantly save costs would select an option with a higher X factor but a higher percentage of the saved earnings to go to shareholders, i.e. a lopsided earnings sharing mechanism, such as 70%-30%. In contrast, the utility who is unsure about cost estimates or is worried it will incur more costs than expected would likely select an option with a lower X factor but a 50%-50% earnings sharing mechanism.

- Cost trackers that incorporate incentives. Incentivized trackers relax the linkage between cost and revenue. For trackers that true up a forecast of the targeted cost to actuals, one common means of incentivizing is to make the true up less than 100%.

- Cost trackers for innovative pilot programs supporting new technologies that achieve public policies. An MRP's strong incentives for cost containment and concerns about prudence can make utilities reluctant to adopt new technologies; this cost tracker would counter-act that reluctance.
- APMs focused on costs covered by trackers where the utility is not incentivized to control costs.
- If not already addressed through an APM, ROE premium for facilitating DG development.
- Efficiency carryover mechanisms (ECM) that allow a utility in subsequent MRPs to benefit from its efficiency savings from prior MRPs through a higher ROE in the new MRP.[29]
- No earnings sharing requirement to facilitate greater marketing flexibility.[30]
- Additional marketing flexibility, in the form of light-handed regulation of optional rates and services, which can include rates calculated on the value of rather than the cost of services.
- Flexible regulation of optional tariffs for power purchases from DG customers. These tariffs could be used to encourage placement of DG where it has special value in distribution cost containment.

2. Example Regulatory Packages for Industry Structure 2:

a. VIEU Example: Industry structure 2 reflects a more traditional approach and accordingly, so will the attendant ratemaking. General rate cases – based on cost-of-service—will continue at current intervals but will use forward-looking test years. Cost trackers will be used for fuel, purchased power costs and changes in policy that cause large unpredictable costs. Traditional decoupling will be applied based on a revenue-per-customer approach.[31] However, EV services will be exempt from decoupling.[32]

[29] In the absence of an ECM, a utility's performance incentives weaken towards the end of an MRP since any upfront costs for improving long term efficiency reduces the utility's earnings, whereas expected efficiency gains are passed through to customers in future rate plans.

[30] The scope of the utilities' marketing flexibility under the Competitive Structure will be narrower than under the Partnership Structure.

[31] When rate cases are held at irregular and infrequent intervals, revenue decoupling is generally preferred for this purpose for most service classes. However, if rate cases are held on a regular basis, decoupling is less important.

[32] We propose to exclude EV charging loads from decoupling as a straightforward way to bolster utility incentives to promote EV loads, which can help to recover fixed costs, build loyalty to the grid, and improve the company's environmental footprint. Time of use rates could in principle be required for EV loads.

As with the other regulatory packages, performance incentives will be applied to align utility and customer interests. Specifically,

- SAIFI, SAIDI and CAIDI – penalty only
- Time-Sensitive Pricing – reward and penalty
- Energy Efficiency Targets - reward and penalty
- Interconnection Times for DG –penalty only.

Because APMs can augment revenue decoupling to reduce the utility's incentive to increase its sales, regulators may want to add metrics to achieve that goal.

To promote partnerships with third-party vendors, an earnings-sharing mechanism will be established that allows shareholders to share in cost-savings resulting from partnering with non-affiliate vendors. Earnings-sharing will also be applied to costs avoided by increasing the efficiency of utility operations.

b. UDC Example: Under industry structure 2, UDCs continue to be prohibited from participating in DG, community renewable energy and large storage on the Grid Edge. Consequently, as to revenue streams, the primary difference for UDCs between structure 1 and 2, is that UDCs are free to develop microgrids. Revenue increases arising from microgrids is not sufficiently different to warrant a separate regulatory package. Hence the regulatory packages for UDCs under industry structure 1 would be the same for structure 2.

Statutes and regulations should enable the PUC to create tailor-made packages for each of its utilities.

C. A REGULATORY PACKAGE FOR THE LONG-TERM FUTURE:

None of the regulatory packages presented above anticipate a radical departure from the *status quo* in the near term. However, the long-term future may look dramatically different than the near term. It is foreseeable that competitive markets for DG and other DER could flourish and begin to encroach on the utility's services within the BDS. While this scenario is unlikely for most U.S. electric utilities in the near term, economic trends justify at least a cursory consideration of a system where most of the functions currently provided by utilities would be open to the market. This would create competitive pressures that are similar to those which railroad and telecom utilities have faced.[33]

[33] Mounting competition in telecommunications gave rise to a significant body of literature on the regulation of utilities subject to competitive entry. See, for example, Toward Competition in Local Telephony, William J. Baumol and J. Gregory Sidak, MIT Press, 1994.

In situations where advanced DER competition is occurring, utilities would likely raise concerns about stranded assets, that entrants were "cream-skimming" the most lucrative customers, and that the current regime offers insufficient pricing flexibility for the utility and affiliated companies to respond to competitive alternatives. Entrants would raise concerns about cross-subsidization and predation that would allow non-economic pricing of the utility's services and thwart socially beneficial competition and innovation.

Traditional cost-of-service regulation is incompatible with competitive entry into the utility's market. An approach that would make sense in this hypothetical scenario would be closer to the incentive regulation end of the continuum, similar to the systems used to regulate incumbent local telecom exchange carriers. Such a system could include features such as the following:

- **MRPs with lengthy plan terms:** Rate cases could be deemphasized even further through efficiency carryover mechanisms and provisions for plan extensions.
- **ARMs unlinked from utility-specific cost forecasts:** ARM designs based on general industry cost trends or incentive compatible "menus" could be more attractive to many utilities due to slow rate-base growth.
- **Higher returns on equity (ROE) when rate cases occur:** Due to increased operating risk, utilities are likely to need higher ROEs to attract capital.[34]
- **APMs for a range of quality metrics:** Utilities will be under greater pressure to reduce operating costs due to the combined effects of lengthy MRPs and competition. A system of quality metrics would ensure that cost reductions are the result of efficiency improvements rather than unacceptable degradation of service quality.
- **Greater marketing flexibility:** Utilities could be allowed to offer significant discounts for services to competitive markets. To facilitate this flexibility, earnings sharing mechanisms could be phased out.
- **Independent administrators for energy efficiency and low-income subsidies.**
- **Reconsideration of utility obligation to serve:** As markets and technology evolve, it may no longer be necessary for the utility to be the provider of last resort.

VI. STAND-ALONE ISSUES:

The former Commissioners and stakeholders of this Project agreed that it would be beneficial to separately address two distinct areas – the provision of electric service to

[34] Due to increased operating risk, utilities are likely to see increases in their cost of capital and may need higher ROE's. However, if the rate of change is rapid and disruptive, regulators may need to balance the utilities' need for higher ROE's with their need to avoid price increases as they enter a competitive environment.

low income customers, and transmission policy in a time of energy transition – because of their importance and unique characteristics. The low-income framework attempts to assist policymakers in approaching how to ensure that the technologies associated with decentralization remain available to all income segments, while ensuring that low income customers are not negatively impacted by rate changes associated with the energy transition. The transmission framework details approaches to the siting of multi-state transmission lines, as certain regions of the nation continue to build out their renewable energy potential and seek to access clean energy from more remote areas.

A. LOW-INCOME CUSTOMERS

1. Basic Service Coverage by Providers of Last Resort in a Time of Increasing Decentralization

As the energy system changes over time and customers are increasingly served by a diverse set of companies, policymakers will have to determine how best to ensure that low-income consumers receive basic utility coverage. As DER technologies proliferate, policymakers will seek out ways to ensure that the energy system remains one in which all customers have access to cost saving technologies, and that as customers leave the grid, the low-income community is not saddled with a disproportionate share of fixed costs. This framework is designed to address the twin questions of how to allow access for all to new technologies and grid services while preserving universal service. In particular, it calls for the continuation of basic service coverage for low-income customers throughout the coming energy transition; envisions new programs designed to serve low-income customers that allow optionality and that can serve also as energy efficiency measures; allows for the implementation of CRE and storage and in some cases the rate-basing of DER in low-income communities; calls out the need for regulators to ensure that fixed costs do not disproportionately impact low-income customers; and suggests the designation of a subsidy that would shield low-income customers from fixed cost recovery by utilities associated with grid defection.

a. 24-7 Basic Service Coverage

- Low-income customers will continue to receive 24-7 basic service coverage under a subsidized rate, based on income level, as is the case in most states today. It will be particularly important in the early years of this energy transition to ensure that low-income customers have access to reasonably priced electricity, as early adopters of technology leave the system and others with fewer means to do so remain with providers of last resort.
- Length of subsidy: Low-income customers will continue to be subsidized for as long as they remain low income and for as long as there are providers of last resort. If at some point there are no longer providers of last resort, subsidized rates will be replaced with direct monetary subsidies.

a) Administration of subsidies: Low-income subsidies will continue to be administered by providers of last resort or the state, depending upon the determination of the jurisdiction.

b. Low-Income Pay-as-You-Go Service Systems
   - Regulators may look to in-home energy card-based systems as an approach to specific customer segments that may prefer this as an option, including low-income customers and others, who are more likely to prefer the optionality that pay as you go systems allow. Pay-As-You-Go programs have been successfully adopted in places like Arizona, where the Salt River Project deploys card readers in homes and allows any customer, whether low income or not, to pre-purchase their electricity for the month at local convenience stores or at utility locations.
   - This system is voluntary. The intent of such a program should be to expand low-income customers' options for affordable and reliable service rather than to reduce their options.

2. Energy Efficiency, Demand Response, On-Bill Financing, and DER

a. Energy Efficiency, Weatherization and Demand Response
   - States will target weatherization programs toward low-income homeowners who are receiving subsidized rates, to the extent that there are weatherization efforts in a given state.
   - Companies engaging in DR would interface with low-income customers as they would other customer segments.

b. On-Bill Financing: On-bill financing for EE measures and solar have been adopted in some states and could provide an additional avenue for ensuring that low-income customers are not left behind by early adopters of emerging technologies. It is likely that on-bill financing will be extended to all DER measures in those jurisdictions where it is adopted.

c. DER
   - Providers of last resort in areas where there is little current build-out of DER and little competition by DER companies could propose to rate base DER that is targeted at low-income communities, thus increasing the likelihood that these communities will have equal access to DER services in the near to mid-term.
   - Customers who receive low-income assistance would be eligible for DER so long as the DER in question poses benefits for the system as a whole. Once a form of DER is commoditized, it is envisioned that low-income customers will have widespread access to the technology.
   - Storage: Like solar, there may come a time when storage becomes commoditized and low-income customers will have equal access to this technology without the need for regulatory intervention.

- CRE/DER: Third-party financiers may elect to install solar, storage or other forms of DER in low-income communities. Several states are beginning to experiment with the idea of utilizing CRE as a method of deploying renewables in low-income communities. Under this approach, a utility or third party will build the system and allocate the output to multiple end users. From a finance perspective, CRE tends to vary risk by allowing for multiple payers on the system. As mentioned earlier, CRE would likely be limited to between 2 and 10 MWs.

3. Recovery of Stranded Costs

- If socialized to ratepayers, the pass-through of stranded costs may increase low-income customers' bills, such that the inability of low-income customers to afford electricity would be further exacerbated. Therefore, regulators will likely need to address the question of whether and how stranded costs are passed through to customers.
- Policymakers will need to determine whether to allow stranded costs associated with legacy utility systems to be passed on to low-income customers. In some jurisdictions, low-income customers are already shielded from paying such costs as riders for renewable energy and energy efficiency.
    a) Options: Regulators could choose to prevent the pass through of stranded costs entirely, allow a portion of stranded costs to be recovered from low-income customers, or allow stranded costs to be recovered on a commensurate basis with other residential customers.
    b) To the degree that regulators want to provide price signals to low-income customers, they may choose to include stranded costs in low-income customers' bills to provide a degree of price signals and visibility of the costs, but could choose to pull it back out of the bill via a subsidy.

4. Recovery of Fixed Costs

- As DER, storage, EE, and other emerging technologies continue to expand, utilities will likely request recovery of lost fixed costs that result from the exit of customers and load from their systems and the concomitant need to maintain the assets that were put in place at one time to serve them. The recovery of fixed costs could come in the form of fixed cost recovery adjustors and other mechanisms, to be implemented by regulators. However, the recovery of these costs will be most impactful – and controversial – where they concern low-income communities.
- Accurate grid access charges would be based on whether appropriate conditions existed at the time and based on accurate cost-benefit analyses.
- Low-income customers would be somewhat shielded from the recovery of fixed cost recovery by utilities, and subsidies would have to rise to accomplish this.

- Customers exiting the grid should pay into a "lock box" designed to increase the low-income subsidy. This "lock box", which would be created by regulators, would be set aside solely for this purpose, and is to ensure the money is reserved for low-income customers and not re-purposed for other issues. For those leaving the grid, it would address intergenerational inequities caused by defection.
- It will become important for regulators to determine how to accomplish these subsidies, and how to ensure that the subsidy itself does not become a market barrier. One option for policymakers to consider would be to implement the subsidy outside the utility system (e.g, through the tax code).

5. Microgrids and Storage

- To the degree that microgrids and storage are considered to provide value to the overall grid and society, regulators will likely encourage companies to consider deploying them in low-income communities. Regulators will want to ensure that communities do not experience "technological deserts" in which microgrids are not deployed in low-income communities. In those instances where there is reticence on the part of third parties to deploy in a given area or community, or where a market has failed to develop for microgrids, regulators should look to allow utilities to invest and ratebase microgrids.
- Cost recovery for micro-grids that are deployed as a result of regulatory intervention for low-income communities will be socialized across existing customers of the provider of last resort.

B. MULTI-STATE TRANSMISSION

The nation may be moving to more decentralized generation, but some regions of the country will continue to need access to remote sources of renewable energy for the foreseeable future. A major challenge for the development of remote renewable energy is the need for new interstate transmission infrastructure to deliver remote resources to high-load markets. Interstate transmission developers must navigate through a patchwork of overlapping and sometimes conflicting federal, state, and local jurisdictions, each with its own interest, political environment, legal precedents, and regulatory requirements. While our federalist system will always create some complications for the building of interstate infrastructure, there are ways to make the process more efficient and less time-consuming while still respecting states' sovereignty and property owners' rights.

This framework recognizes that the differences between the characteristics of DC and AC transmission lines are large enough to justify somewhat different regulatory approaches.

States will vary in the degree to which the following provisions will require statutory changes. Since the passage of legislation can be a lengthy and unpredictable process, some states may choose to focus first on the provisions that can be implemented by administrative rule.

1. Standards for state approval of projects:

- Need or necessity: In states that have not already done so, standards of approval will be broadened beyond "necessity" or "need," to include projects that serve a public interest to a degree that exceeds their public cost and inconvenience. The definition of "public interest" will explicitly include but not be limited to the following:
  a) reducing wholesale electricity prices,
  b) reducing economic constraints,
  c) facilitating energy exports and/or imports that benefit the economy of the state,
  d) improving reliability, and
  e) supporting public policy.

- Definition of public benefit: The state entity responsible for the approval of transmission lines will have authority to consider impacts beyond the border of its state when determining if a line serves the public interest. In some states this will require a statutory change. Examples of regional or national benefits that could be considered when approving new transmission lines include:
  a) development of competition in the wholesale electric market,
  b) lowering locational marginal prices,
  c) transmitting energy from remote locations to serve high-load markets,
  d) improving resource adequacy, reliability, and security of the regional electric grid,
  e) eliminating loop flows,
  f) international benefits (such as access to resources or markets in neighboring countries), and
  g) improved transfers between seams of distinct energy markets.

2. Process for approval and siting:

- Streamlined approval and siting process: Transmission projects can encounter significant time delays, which discourage some lines from being built and drive up the costs of those lines that do make it through the entire process. In some states, the routes of transmission lines must be approved by several different jurisdictions, magnifying the difficulties in planning and completing projects. The approval process should be transparent, consistent, and completed as quickly as possible without shortchanging the rights of property owners along the route.

a) The decision as to whether the line is needed or in the public interest would be made by one entity with statewide jurisdiction, preferably the state's economic utility regulator.
b) Where appropriate, states would establish a statewide board to make recommendations concerning the siting of transmission lines. Other public entities (such as cities and counties) that now control the siting of lines in their jurisdictions will instead be represented on the board when it makes siting decisions affecting those entities.

- Time limits for state approval of interstate and intrastate lines: If suitable deadlines do not already exist, deadlines for approval/disapproval decisions will be set.
    a) The entity responsible for approval must make a decision within 180 days after an application has been deemed complete.
    b) With the consent of the applicant, the decision period can be extended to 360 days.
    c) If the responsible entity has not rendered a decision before the deadline, the application will be automatically approved.

3. **Regional cooperation on approval and siting of interstate lines:**

Each state's regulations for interstate transmission are based on its particular mix of statutes, precedents, political culture, and land use. Differences in regulatory timelines, standards for approval, rules for crossing boundary rivers, and other policies can significantly complicate the process of building interstate transmission. By adding to the risk of interstate transmission development, these differences can lead to higher costs due to the higher returns on equity that FERC allows for such projects. Delays in developing transmission lines also increases the transactional costs for the lines and delays the delivery of the benefits that would be brought by the line. In the worst-case scenarios, delays in the approval process have forced the construction of less cost-effective "quick fixes," which then further reduces the likelihood that a line providing the most cost-effective solution can be approved.

While it may be difficult for states to give up their autonomy in this area, any steps that can be taken toward greater regional cooperation on approval and siting will help reduce the cost of interstate transmission development, and ultimately the costs to the ratepayer. Those steps can include:

- Interstate compacts: Sec. 216(i) of the Federal Power Act (FPA), 16 U.S.C. § 824p, authorizes three or more states to form a compact, subject to Congressional approval, to "facilitate siting of future electric energy transmission facilities." Some states have provided explicit statutory authority for their governors to enter into interstate compacts concerning transmission lines; others should follow suit.

- Commission-level regional cooperation: Some states allow their utility commissions to enter into non-binding memorandums of understanding with other commissions to facilitate coordinated action where it is feasible. Other states should adopt this policy.
- Concurrent state approval process: States will adopt legislation allowing them to coordinate the approval process with neighboring states along the proposed path of an interstate transmission line. This process will apply to both the determination of public interest or necessity and siting. Each state will make its public interest and necessity findings and approval decisions independently according to its own policies and procedures, but they will do so in coordination with the other states on a common timeline, with joint hearings to the extent possible. The governor will be authorized to enter into memoranda of understanding with adjacent states to authorize the relevant agencies in those states to do any of the following in the event a proposed route crosses their boundaries:
    (1) Meet jointly at the staff level with their counterpart agencies in adjacent states and transmission developers during the pre-application informational process;
    (2) Establish protocols for sharing information among states, taking into consideration the differences between states' open records laws and confidentiality practices;
    (3) Establish uniform criteria for applications, to provide a "one-stop" application process;
    (4) Adopt compatible standards for determining where lines can cross state boundaries, including boundary rivers or other geographic features.
    (5) Hold a joint evidentiary hearing for the final siting for the route. However, this will not preclude individual states from holding an additional evidentiary hearing within their state prior to the final hearing, to provide convenient locations for objectors to present their evidence and hear rebuttal witness responses.

For some of the items in the above list, it may be possible to work out arrangements between three or more states to harmonize their route approval process in one agreement. For others, it may be more practical to work toward bilateral agreements. Therefore, the statutory authorization for such agreements should allow for more than one agreement, establishing different concurrent processes or standards in each agreement. For example, it may be unrealistic to expect a group of states to all agree to the same standards for crossing boundary rivers or other geographic features along state boundaries. Instead, a state may enter into a separate agreement with each bordering state, or an agreement with one bordering state but not another. For example, the state of Illinois might reach an agreement with Iowa on the standards for crossing the Mississippi River along the Illinois-Iowa boundary, a separate agreement with Missouri with different standards for crossing the Mississippi River along the Illinois-Missouri border, a third agreement with Wisconsin for crossings along that border, and a fourth agreement with Indiana governing the crossing of the Illinois-Indiana border. Even though border crossing rules would still vary across the route of a large interstate project, transmission developers would know in advance the rules governing each border crossing and would not have to navigate between two conflicting sets of rules.

Harmonizing the route approval process in different states may require exceptions to some states' laws or rules concerning administrative rule adoption, open meetings, open records, and ex parte communications. Where procedures are governed by statute, the statutes would be amended to allow governors to issue waivers for the limited purpose of complying with an interstate agreement to conduct a concurrent route approval process.

4. **Federal-state cooperation relating to Federal Approvals:**

In 2005, Congress mandated that the federal government streamline federal approvals relating to multi-state transmission projects. The nine federal agencies most involved with transmission projects have been working together to implement this directive. A new federal rule will likely be released in 2015 that will specify methods for coordinating between federal and state entities with jurisdiction over proposed interstate transmission projects.

Regardless of any federal rule, states can adopt the following, which would enhance the state-federal-tribal coordination efforts:

- Any entity that has jurisdiction over the proposed project must meet with the applicant before the application is submitted to identify areas that are likely to slow or stop the siting process. It is important that jurisdictional entities meet together to discuss siting challenges so that the entities can understand how their concerns collectively impact the project;
- If the state has an environmental procedure act similar to NEPA, determine whether the state and the federal government can jointly draft an EIS that would comply with both state and federal laws;
- The state and the federal lead agency would sign a memorandum of understanding setting forth expectations and responsibilities including how the timelines for federal and state approvals would dovetail with one another.

5. Crossing railroad rights of way:

Railroads and abandoned railroad rights of way can cause unreasonable delays and cost increases for transmission projects when there is no way to avoid crossing the right of way and the right of way owner is willing to fully exploit that advantage. Standard procedures would be established within a state for approved transmission lines that cross rights of way owned by railroad companies or their successors in interest.

- Builders will have the right to string conductors across a railroad right of way after notifying the easement owner and paying standard damages per crossing, as long as proper heights and other safety standards are met.
- The easement owner may contest the standard crossing fee and receive a higher payment for damages if it can show additional damages due to unusual circumstances that do not apply to a typical railroad crossing.
- This "pay and go" provision will apply to all transmission lines built in or across the state, whether built by a utility or some other entity.[35]

6. Merchant projects:

- Merchant transmission developers will not be required to meet the state's definition of public utility to construct, own, or operate transmission lines within a state. In several states this will require statutory changes.
- If the developer of a merchant DC project is not requesting the power of eminent domain in a state, state approval will not be required. The state will retain jurisdiction over siting, construction standards, and safety.
- If the developer of a merchant DC project requests the power of eminent domain, the state will require a finding of need or public interest. In addition, the state may choose to require at least one converter station to be located within the state as a condition for granting eminent domain.
- If the developer of a merchant AC project is not requesting the power of eminent domain in a state, the state may require only a finding of no net public detriment for approval. The state will retain jurisdiction over siting, construction standards, and safety.

7. DC lines built by incumbent utilities:

If a state's incumbent utility proposes to build a DC line that will pass through the state but will not have a converter station affecting that state, the provisions of section VI.B will apply to that project if the costs or risks will not be shared by the utility's ratepayers in that state. However, if costs or risks will be shared by the state's ratepayers, a finding

[35] For example, the state of Iowa has had success with a similar pay and go provision.

of need or public interest will be required for approval even if the utility is not requesting the power of eminent domain.

VII. CONCLUSION and NEXT STEPS

Without doubt, the nation's energy system is undergoing significant changes in the sources of electricity, the methods by which it is delivered on the grid, and the diversification of the energy providers who will ultimately provide service to millions of American consumers. The Powering Tomorrow Initiative set out through a collaborative process led by four former Public Utility Commissioners and with the input of industry stakeholders to design regulatory packages that would be capable of assisting in this transition under varying industry structures.

Specifically, the Powering Tomorrow Initiative and its participants identified two distinct industry structures. The first Industry Structure, **Competition on the Grid Edge ("Competitive Structure")** describes an industry design in which utilities continue to own and operate the Basic Distributions System (BDS) but where competition would occur for the provision of energy services and products on the Grid Edge. The second Industry Structure, **Utility Partnership and Ownership on the Grid Edge, "Partnership Structure,"** describes a more graduated approach to change in the utility structure, one in which changes would occur more incrementally, and utilities would be allowed under certain conditions, to own and operate elements of the Grid Edge.

This report also details five separate regulatory packages that could accompany either of the two industry structures: Vertically Integrated Utilities in the Competitive Structure (industry structure 1); Utility Distribution Companies in the Competitive Structure (industry structure 1); Vertically Integrated Utilities in the Partnership Structure (industry structure 2); Utility Distribution Companies in the Partnership Structure (industry structure 2): and a Regulatory Package for the Long-Term Future.

Finally, we offered two stand-alone regulatory frameworks designed to address issues that will almost certainly become pertinent during any state's design of its regulatory system and industry structures: Low-income customers and Multi-state Transmission. The continued protection of low income customers will be particularly important for regulators and industry representatives, as they seek to ensure that this customer segment is able to access emerging technologies and does not shoulder unsupportable burdens related to the energy transition. Transmission will also evolve and present challenges to policymakers as they seek to institute more efficient and expedited approval processes while ensuring that the nation develops its access to renewables both close to load pockets and in locations far from population centers.

The Powering Tomorrow Initiative does not purport to present an exhaustive compilation of the universe of potential responses to the changes occurring in our energy system. However, we believe that regulators in a multitude of jurisdictions and regulatory traditions could seize upon these structures and packages and find within them an approach that would satisfy the twin goals of allowing providers of last resort to continue operating utility systems at a profit when well-run, while also preserving the ability of competitive energy providers to grow their presence in this evolving energy landscape.

Powering Tomorrow will continue with a third Phase, to occur in 2015 and 2016, in which we will convene key stakeholders, policymakers and thought leaders to refine these Industry Structures and Regulatory Packages into a Model Code of Regulation and Legislation that could then be tailored to legislation and regulatory proposals for specific states.

Appendix A: Tools for Incentive Ratemaking[36]

Attrition Relief Mechanism (ARM): ARMs give a utility an *allowance* for cost growth rather than reimbursement for its *actual* cost growth. Rate adjustments can either be made as stair-step increases at scheduled intervals based on cost forecasts, or by indexing rates to key variables such as customer growth, inflation, or other industry cost trends. These two methods can be combined into a hybrid approach. In the U.S., hybrid ARMs typically involve indexing for operating and maintenance (O&M) expenses and stair steps for capital costs.

ARMs can be used to protect utilities from revenue losses due to energy efficiency, distributed generation, and other changes that reduce energy sales. Instead of being incentivized to sell more energy, the utility is under pressure to keep its cost within the budget provided by the ARM.

One disadvantage shared by traditional ratemaking and ARMs is that utilities have much more information than regulators about present and future utility costs. However, regulators may be able to construct ARMs in a way that encourages the utility to reveal its expectations of future costs. A menu of options could be developed that combines various indexing formulas with corresponding rates of earnings sharing. As the allowable revenue growth increases, the required earnings sharing would decrease. By choosing from this menu of combinations, the utility would reveal its true expectation of cost growth over the next few years. There is precedent for this “incentive compatible” approach in telecommunications regulation.

Award/Penalty Mechanisms (APM): APMs adjust revenue automatically with awards and/or penalties based on utility performance. (See Performance Metric System)

Cost Trackers: Cost trackers (or riders) allow utilities to have faster recovery of certain costs. The costs are tracked and recovered between rate cases. A three-part test is traditionally used to determine costs eligible for trackers, with trackers limited to costs that are (a) large, (b) volatile, unpredictable, or rapidly rising, and (c) largely out of the control of the utility. Upon verification of the eligible costs, the utility is allowed to begin recovering those costs in rates. Cost trackers can reduce risk for utilities and increase the amount of time between rate cases. On the other hand, trackers can reduce the incentives for utilities to act prudently and control covered costs, especially if regulators are not given sufficient time to review those costs. Trackers can shift risk to ratepayers, and regulators can be under pressure from utilities to expand the use of trackers to costs that do not meet the three-part test.

Trackers are sometimes proposed as a way to reduce disincentives for utility expenditures on costs related to achieving important public policy goals even if those costs do not meet the three-part test. For example, trackers can be applied to the costs of energy efficiency programs, advanced metering infrastructure (AMI) deployment, demand response

[36] This appendix summarizes a wide variety of ratemaking tools, including some tools that are not discussed in the body of the report.

programs, distributed storage, microgrids, and other costs related to distributed energy resources (DER).

Earnings Sharing Mechanism (ESM): ESMs automatically adjust rates to share earnings surpluses that result when the utility's rate of return on equity (ROE) deviates from its regulated target. They can be used to share benefits of better utility performance with customers and can reduce the risk of excessive utility earnings. Some plans also contain "off-ramp" mechanisms that permit plan suspension when the ROE is unusually high or low.[37]

Lost Revenue Adjustment Mechanisms (LRAM): LRAMs are conceptually similar to revenue decoupling but are more targeted. Rather than completely separating the utility's revenue from its sales volume, LRAMs compensate utilities for revenue lost for specific reasons, such as energy efficiency or DER. For example, if growth in distributed generation causes a utility's sales to be lower than it would have been without the DG growth, an LRAM could allow the utility to recover those lost earnings through revised rates spread across its customer base. An advantage of LRAMs is that they can be used to target specific programs or goals when policymakers are uncomfortable with complete decoupling.

By themselves, LRAMs may eliminate the utility's disincentive to pursue energy efficiency or support DER, but they will not completely eliminate the utility's incentive to increase earnings by increasing sales. It can be difficult and expensive to conduct the analyses necessary for estimating lost revenue attributable to the measures targeted by an LRAM, and dueling estimates of lost revenue can trigger extensive litigation in rate cases.

Revenue Decoupling: Revenue decoupling mechanisms (RDMs) adjust rates periodically to correct for deviations of a utility's actual revenue from its revenue requirement. Revenues of services subject to decoupling then closely track the corresponding revenue requirements. The most common decoupling approach is to base the revenue requirement on the number of customers served rather than the volume of energy sales. Fluctuations in energy sales may cause a utility to temporarily over- or under-collect revenue, but that can be addressed by periodic true-ups to adjust rates for variances between actual and allowed revenue.

Revenue losses are typically recovered by raising volumetric charges, but fixed charges can also be raised. One drawback of using volumetric charges to recover lost revenues is that the higher per kWh charges can blunt the price signal to customers for energy efficiency. It also allows DER customers to bypass the decoupling mechanism.

[37] ESMs could also be structured so that customers would share the risk of excessive utility losses, with rates automatically increasing to help cover unusually large deficits caused by factors other than poor utility performance. However, assuming an ESM had an "off-ramp" clause, it is more likely that the utility would deal with excessive deficits by invoking that clause.

Under "adaptive decoupling," revenue shortfalls or overages are reconciled by adjusting the customer charge. If the utility loses a large amount of sales, it collects more revenue through the fixed customer charge. Conversely, if the loss of sales is smaller than expected or if sales actually grow, the fixed charge does not have to change very much and may even go down. By approaching lost sales in this manner rather than by raising the fixed charge in anticipation of lost sales, the utility raises its fixed charge only if it needs to, and not as a preemptive strike to discourage DER or other measures that might reduce sales.

By itself, an RDM does not allow growth in base revenue even if utility costs increase due to inflation, customer growth, or other changes in business conditions. RDMs are therefore typically combined with revenue adjustment mechanisms that provide automatic escalation of the revenue requirement.

Decoupling is one of the simpler mechanisms for removing the utility's disincentive for supporting energy efficiency programs or distributed energy resources (DER), because there is no need to calculate lost sales. It also makes utility earnings less volatile and reduces the need for frequent general rate cases. By reducing the utility's risk, DCMs may allow regulators to grant lower returns on equity without damaging the utility's ability to attract capital. One potential drawback of revenue decoupling is that with less incentive to increase sales, utilities may be slower to pursue opportunities such as expanded services for electric vehicles.

In addition to the approach described above, lost revenue adjustment mechanisms (LRAMs) and fixed/variable pricing can be viewed as variants of decoupling. (See LRAMs and Fixed/Variable Pricing above for details.)

Ideally, a decoupling mechanism should maintain the incentive for the utility to earn a profit through good performance, which prevents the shifting of risk from the utility to the customers. Rather than removing the risk of losses, decoupling should change the factors determining profitability so that utilities' financial success is determined by improved service, reliability, and meeting important public policy goals rather than by increasing energy sales.

One problem with decoupling is that it can eliminate the utility's short-run incentive to bolster revenue even where it is desirable, as in the provision of electric vehicles and green power services or special contracts to attract large load customers. This problem can be addressed by excluding such services from decoupling. These services can, alternatively, be accorded a "partial" decoupling treatment in which the utility is permitted to keep a percentage of the revenue variances that might result from aggressive promotion.

Multi-year Rate Plan (MRP): An MRP sets rates for a utility without frequent, full true-ups to its actual cost of service. General rate cases are suspended for several years (often 3 to 5 years). Adjustments to rates are instead based chiefly on an attrition relief mechanism (ARM) and selective use of cost trackers. An award/penalty mechanism linked to performance metrics can be used to make sure management pays attention to an array of goals that are important to customers and the public.

MRPs can be used to reduce the frequency of rate cases, make revenue more predictable for the utility, and facilitate greater marketing flexibility. . Utilities in MRPs can respond more quickly to changing circumstances, such as when fast-emerging needs or opportunities require new capital investment. The reduction in regulatory lag can reduce the cost of capital for some projects. Regulatory costs can be reduced for utilities, regulators, and consumer advocates. MRPs can be structured to give utilities a strong incentive to control costs and improve efficiency, while rewarding them for actions that are compatible with public policy goals.

Some MRPs feature a **rate freeze** in which the ARM provides no rate escalation during the plan term.[38] Revenue growth then depends on growth in billing determinants and the revenue from rate riders. Rapidly growing costs are often tracked.

One disadvantage of MRPs is that it can be difficult to accurately forecast sales and costs for several years into the future, which can cause utility profits to vary widely from intended targets. Earnings sharing mechanisms may be used to deal with excess or insufficient utility earnings without conducting a full rate case. An "off ramp" can be provided that allows for the plan to be ended ahead of schedule if the company either exceeds or falls short of its allowed return on equity by a predetermined margin. Another potential disadvantage is that utilities might respond to the incentives for cost containment by shortchanging investment on long-term needs such as reliability. This can be addressed through award/penalty mechanisms.

(See sections on ARMs, Cost Trackers, Earnings Sharing Mechanisms, Reward/Penalty Mechanisms, and Performance Metric Systems.)

Performance Metric System: As the name suggests, a performance metric system is based on measurable utility performance outputs. Performance metrics (aka "outputs") quantify utility activities that matter to customers and the public. A familiar example is the system average interruption duration index ("SAIDI"), which measures a dimension of reliability.

A typical approach is for a commission to determine the utility's base rates through a conventional cost of service rate case, and then add some performance-based incentives that allow the utility to earn more or less revenue based on its success in meeting measureable performance standards. Target or benchmark values are established for key metrics. The performance standards and incentives are clearly spelled out in advance rather than determined in an ad hoc, after-the-fact manner. Performance can then be measured by comparing the utility's results to the targets. Some metrics can become components of **award/penalty mechanisms** (**APMs**) that adjust revenue automatically

[38] In the context of revenue decoupling, an analogous concept would be a freeze on revenue *per customer*.

with awards and/or penalties based on utility performance. For example, utilities that demonstrate superior performance can be granted higher rates of return.

It is not unusual for states to employ performance incentives to some areas of utility performance. For example, according to a report by the Edison Foundation, in 2013 there were 28 states with performance incentives for energy efficiency.[39] However, there is significant variation among states in the use and scope of performance-based ratemaking incentives, and considerable room in many states to adopt or expand performance incentives. For many states, targeted performance-based incentives may be the most efficient and effective first step they can take toward realigning utility incentives to be more compatible with the goals outlined in the Powering Tomorrow First Principles.

APMs tied to performance metrics can encourage a utility to control costs when its incentive to contain cost would otherwise be especially weak, such as when cost trackers are employed. APMs with performance metrics can also encourage utilities to work toward goals that are not rewarded or encouraged through traditional cost of service regulation, such as energy efficiency, reduced interconnection times, distributed generation penetration, etc.

Areas where performance metrics may be useful include:
- Penetration rates for DER
- Environmental goals
- Reliability; CAIDI and SAIFI metrics
- Time sensitive pricing
- Integration of new technologies
- Penetration rates for energy efficiency, reaching energy savings targets, and the development of innovative energy efficiency programs that meet societal cost tests
- Deployment of micro-grids
- Integration of multiple microgrids and interconnection between microgrids
- Deployment of smart inverters
- Deployment of fuel cells where appropriate
- Conservation voltage reduction
- Customer satisfaction
- Reduction in line losses
- Penetration rates for residential, commercial and industrial storage
- Sharing of customer data with customers and their elected DER or EE providers
- Penetration rates for EV's and EV charging stations
- Deployment of utility-scale renewable energy projects and other clean energy projects, whether under PPA's or utility owned, that assist states in meeting carbon requirements like the EPA's Clean Power Plan or that can be utilized in carbon markets like RGGI or other regional markets developed in response to the Clean Power Plan

[39] The Edison Foundation, *State Electric Efficiency Regulatory Frameworks*, July 2013, p. 3

- Deployment of transmission that meets federal or state policy prescriptions, like regional or ISA planning requirements under FERC Order 1000
- Penetration rates for the deployment of combined heat and power
- Internal business cost reductions at the utility

States can choose among several general categories of mechanisms to reward or penalize companies on the basis of performance metrics, including:

- Return on Equity adjustments.
- Frequent true-up of costs and adjustments to revenue requirement when companies meet performance goals.
- Rebates to customers when companies fail to meet performance goals.

If APM provisions become out of date or lead to unintended consequences, commissions need to be able make changes without depending on legislatures to rewrite statutes. In addition, different utilities in the same state may face different challenges or have different capacities to meet performance goals. Therefore, statutory APM provisions should be limited to authorizing the state utility commission to implement performance metrics and incentives (if that authority does not already exist or is unclear), and possibly directing the commission to establish performance incentives for meeting certain goals deemed important enough to be codified. The details of design and implementation should be delegated to the commission, however. Unless a state has an unusually quick and flexible administrative rulemaking process, the commission should be allowed to establish and fine-tune the details of performance metrics and incentives through its ratemaking process rather than the administrative rules of its agency.

Pilot Projects: Special funding and reward packages may be granted to pilot or demonstration projects that encourage innovation. An example is the Brooklyn/Queens Demand Management project, under which Consolidated Edison of New York can earn a special return for aggressive demand management that postpones the need for a substation in an urban area with brisk load growth. Projects like this will often be considered in rate cases but can also be handled outside of the rate case context.

Straight Fixed Variable Pricing: Typically, electric utilities recover a portion of their fixed costs through the variable rates that apply to the volume of energy used by the customer. In contrast, straight fixed variable pricing is based on the principle that all fixed costs of providing access to electric utility service (such as the cost of building and maintaining the system) should be recovered with a fixed customer charge, while only the variable costs of generating and delivering energy should be recovered through per-kWh variable charges. If the volumetric rates are set to accurately reflect variable costs, straight fixed variable pricing can be viewed as a variant of decoupling because the utility’s profit does not depend on energy sales.

Some have argued there are significant conceptual problems with this pricing approach. Critics have asserted that there is no economic theory that suggests that a utility should recover fixed system costs through fixed charges.[40] Just as gasoline providers in competitive markets recover both fixed and variable costs exclusively through volumetric charges, in order to provide proper signals as to long-run marginal costs, the volumetric rate the utility charges must recover a substantial portion of system fixed costs to provide a signal as to long-run avoided costs.[41]

With higher fixed charges and lower usage charges, the utility has less incentive to resist energy efficiency or DER efforts, providing that the usage charges are not lower than the marginal cost of providing energy. Other advantages of straight fixed variable pricing include reduced fluctuation of customer bills between seasons and stabilization of utility earnings. Disadvantages can include customer resistance and adverse impacts on some low income customers. While utility companies may have more incentive to pursue energy efficiency and DER, customers may have less incentive to do so because their reduced usage will have less impact on their monthly bills.

[40] See Severin Borenstein, "What's so great about fixed charges?" Energy Institute at Haas, November 3, 2014.
[41] See Jim Lazar and Wilson Gonzalez, *Smart Rate Design For a Smart Future*, Regulatory Assistance Project, July 2015.

APPENDIX B

For another perspective on aligning ratemaking provisions with policy objectives and changing energy markets, see *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, April 2014. http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1