FUTURE ELECTRIC
Utility Regulation

Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in scale to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity on implications are common to both time periods. DOE played a useful role during the 1990s' discussion and debate by sponsoring a series of papers that illuminated and dug deeper on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues, with the aim to better inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of new and improved technologies, together with changing customer and societal desires and needs, both of which are coupled with possible structural changes in the electric industry and related changes in business organization and regulation. Some of the technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some of the technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To maintain effectiveness in providing reliable and affordable electricity and its services to the nation, power sector regulatory approaches may require reconsideration. Historically, major changes in the electricity industry came with changes in regulation at the local, state or federal levels.

The U.S. Department of Energy (DOE), through its Office of Electricity Delivery and Energy Reliability's Electricity Policy Technical Assistance Program, is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, work closely with DOE and LBNL to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Executive Summary

The emergence of distributed energy resources (DERs) that can generate, manage and store energy on the customer side of the electric meter is widely recognized as a transformative force in the power sector. This report focuses on two key aspects of that transformation: structural changes in the electric industry and related changes in business organization and regulation that are likely to result from them. Both industry structure and regulation are inextricably linked. History shows that the regulation of the power sector has responded primarily to innovation in technologies and business models that created significant structural changes in the sector's cost and organizational structure.

Our structural analysis suggests three major changes in the power sector and the regulation of utilities.

First, the emergence of competitive alternatives to energy and capacity supplied by the bulk power system—the "grid"—will dramatically increase customers' elasticity of demand for power, leading to downward pressure on both utility profitability and cost structures. After a century of utility concerns over whether rate increases will be high enough to allow full cost recovery, the emergence of elastic demand for electricity will shift the focus to whether utility costs are simply too high to be recoverable.

Second, while we see the bulk power system enduring, albeit with little growth, the natural monopoly of the distribution utility will be eroded. However, even as distribution utility economies of scale are undercut by new technologies capable of being offered by multiple firms, economies of scope and coordination among these technologies will become increasingly important. DERs will not only improve customers' energy costs, resilience and power quality, they can help utilities avoid risky capital expenditures and operate their systems more efficiently. By facilitating DERs, utilities can both lower their costs and increase the benefits they can offer customers who deploy DERs, providing an incentive to remain connected to the distribution system rather than defect from it.

Third, the fundamental role of the utility will evolve to support this lower cost, higher value service that can be provided when customer-facing DERs are coordinated to not only provide customer services, but to create value for the distribution utility and grid as well. However, that evolution may occur in different directions. One points towards a major utility presence in sourcing, financing and optimizing DERs for customers. The other points towards a major role for competitive firms in not only providing DERs through competitive channels, but also in competing to tailor DERs' performance and optimize the total value they can create in this emerging, three-sided market comprised of customers, distribution utilities and the grid itself.

The report begins with our analysis of the ongoing structural evolution of the power sector, from the invention of the integrated utility with strong natural monopoly characteristics in the 1890s, through the restructurings in the late 20th century brought about by the exhaustion of economies of scale in generation and the expansion of economies of scope in dispatch by regional transmission organizations beyond the borders of single utilities. We extend this structural analysis forward to a world in which DERs are competitive with grid power in price and performance to derive the conclusions summarized above. The report ends with two competing views of the future. In one, utilities successfully evolve to play the major role in using DERs to provide services to customers. In the other, these functions are increasingly performed by competitive firms using advanced and largely decentralized digital technologies, and the utility "sticks to its knitting" in terms of providing and maintaining infrastructure needed to deliver basic energy and capacity services, while depending on DERs to entice its customers to remain connected to the system and help the utility maintain sustainable cost levels.

I. Technology Systems, Market Characteristics and Regulatory Responses

A. History shows regulatory policy evolves in response to technologies and business models that create or change market structures.

This report addresses the fundamental question of the alternative types of industry structures, including regulatory and other institutional arrangements, that may be appropriate in response to high levels of distributed energy resources (DERs), assuming they reach price and performance characteristics that support such a scenario. In evaluating appropriate regulatory responses, we focus primarily on the impact of high levels of DERs on what are known as "market failures" associated with today's approaches to electric generation, transmission and delivery. We focus on these structural features because they have largely justified today's various forms of regulation. Primary among these market failures are natural monopolies associated with strong economies of scale and scope, a variety of externalities—both positive and negative—and certain "public good" characteristics of network service.

Basing business models and regulatory paradigms on the characteristics of new technology systems has a long history in the U.S. power sector. Indeed, that is how the current regulatory paradigm was itself established. The leading pioneer of both the integrated electric utility business model and its dominant regulatory paradigm was Samuel Insull, who served as Thomas Edison's personal secretary, and then as a leading executive of the General Electric Company, before moving to Chicago in 1890 to realize his vision of an integrated electric utility. In 1897, as the head of his 6-year-old Chicago Edison Company, Insull made this bold assertion to the 21st convention of the National Electric Light Association:

> The best [electric] service at the lowest possible price can only be obtained … by exclusive control of a given territory being placed in the hands of one undertaking. In order to protect the public, exclusive franchises should be coupled with the condition of public control requiring all charges for services fixed by public bodies to be based on cost, plus a reasonable profit.[1]

Insull's early advocacy for exclusive monopoly franchises coupled with price regulation was based on the success of his new business model over the previous six years. In that time, he had acquired 14 downtown Chicago micro-utilities, scrapped out their inefficiently small reciprocating steam engine generators and replaced them with much larger ones at his 6.4 MW Harrison Street station.[2] At the same time, he embarked on an aggressive marketing plan that included low off-peak electric rates to build a flatter and more economical load shape.[3] By 1898, these factors had driven average electric rates in Chicago down from 20 cents to 10 cents per kWh.

By 1910, Insull had installed the first steam turbine generators in the U.S. at Commonwealth Edison's Fisk Street Station, with double the energy efficiency of Harrison Street, and expanded his original 4,000-customer base to over 100,000. The combination of larger, more efficient generation and a larger, more diverse load allowed him to further drive down average electric rates to 5 cents per kWh. In 1913,

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[1] Robert Bradley, *Edison to Enron, Energy Markets and Political Strategies.* 2011. Scrivener Publishing.

[2] Insull's willingness to simply discard relatively new equipment that was rendered uneconomic by his innovations ran counter to accepted business practices, and he often claimed that "the junk pile is our most valuable asset." Bradley, *id.* at 125.

[3] Insull also invested heavily in batteries to store electricity near where it was needed, but found the lead acid technology of that era too expensive and difficult to maintain—and consigned them to his growing junk pile.

Insull replicated this unprecedented urban success story in the towns and farms of rural Lake County, Ill. There, replacing small, local generating companies with a single, large company interconnected with new, larger boilers and steam turbines lowered his utility's costs by 60 percent and customer rates by 18 percent—making consumers unambiguously better off, while significantly increasing profits for investors in his Commonwealth Edison affiliate North Shore Electric Company.[4]

Insull coupled his success in achieving these stunning economies of scale and scope with a relentless advocacy campaign for exclusive service territories coupled with cost-of-service regulation for utilities like his.[5] The success of both his business model and his policy advocacy can be seen in the architecture of today's grid, utilities and regulatory statutes. Insull's model was not, however, free from problems over the long history of the utility industry. In the latter part of the 20th century, exogenous shocks and utility cost overruns, coupled with the emergence of combustion turbine-based generation technologies, led many to question the fully integrated utility business model.

a) <u>Natural monopoly has been a key driver of the existing regulatory paradigm.</u>

The economies of scale in boilers and turbines, and of scope in load diversity, that Insull demonstrated 100 years ago are textbook examples of what economists today call "natural monopoly"—a characteristic of certain technologies that can make it significantly less costly for a single firm to serve an entire market than for multiple firms to do so.[6] As Insull himself noted, where such conditions exist, policies that award a legal monopoly to a single firm, and prevent it from pricing above cost, can materially improve on competitive market outcomes. Variants of this policy approach continue to be recommended by economists today for situations where there are strong natural monopolies.[7] It is sometimes hard, after 100 years of regulation, to distinguish legal monopolies from natural monopolies. However, history itself is clear that natural monopolies were demonstrated first, through much lower costs achieved by single, integrated firms, and legal monopolies were granted subsequently, in response to the consumer and investor benefits they could create using large coal boilers integrated with large distribution systems.[8] This pattern of regulation following changes in technologies and market structure did not end with Insull's family of Edison companies.

b) <u>Erosion of power sector natural monopolies due to innovation creates new regulatory paradigms.</u>

Despite the profound natural monopoly characteristics of large central-station power and an integrated grid Insull demonstrated over a century ago, subsequent waves of innovation have eroded that natural monopoly, leading to both new business models and new regulatory paradigms. In the 1980s and 90s, a

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[4] Edward Kahn, *Electric Utility Planning and Regulation.* 1988. ACEEE.

[5] Robert Bradley, *id.* at 154. Insull and his core investors owned a pyramid of controlling shares in many of these new regulated utility companies—a fact that was to have disastrous consequences for Insull and many small investors when stock prices collapsed in the Great Depression.

[6] The discussion of natural monopoly here and in Appendix B draws heavily on Sandford Berg and John Tschirhart, *Natural monopoly regulation: principles and practice.* 1989. Cambridge University Press. Natural monopolies may result from high levels of fixed costs needed to reach efficient scale. This can mean that only investments large enough to serve the entire market allow a firm to reach minimum cost, and once those costs have been invested, it is unprofitable for another firm to invest at either small or large scale.

[7] The Nobel Prize in Economics in 2014 was awarded to Jean Tirole, in large part because of his contributions to the economic theory of natural monopoly regulation.

[8] See Appendix B for a more thorough discussion of natural monopoly. It is especially important to understand that, while a legal monopoly may endure until the law is changed, a natural monopoly disappears as soon as new technologies and business models make it cheaper for multiple firms to serve a particular market than for a single firm to do so.

period of cost overruns at new central-station power plants plus the emergence of efficient, smaller-scale natural gas turbines made it not only possible, but in many states preferable, to decouple power plant development, finance and operation from the incumbent utility. The result was the practical demonstration that multiple, independent firms could develop, build and operate power plants at lower cost than vertically integrated utilities. This gave rise to the widespread conclusion that generation is no longer a natural monopoly. While several basic "power pools" had been in existence since the 1940s, in the final two decades of the 20th century new computer and data acquisition systems made it possible to coordinate power plant dispatch and transmission management across much larger multi-utility power pools, rather than within each vertically-integrated utility. This demonstrated that economies of scope in the electric industry—specifically, the coordination of power plant dispatch and transmission system operation with minute-by-minute changes in electricity demand—could be carried out more efficiently on a scale that exceeded that of individual vertically integrated firms.

As in Insull's day, new technologies and business models that could undercut the less efficient incumbent gave rise to new regulatory policies. These ranged from electric industry restructuring[9] in 16 states to the Federal Energy Regulatory Commission's requirements for all jurisdictional utilities to file open access transmission tariffs and to consider forming regional transmission operators (RTOs). The combination of new technologies and policies ultimately gave rise to today's Open Access Transmission Tariffs (OATTs), independent power producers (IPPs), independent system operators (ISOs) and RTOs and the large centralized wholesale power markets they manage.[10] While some criticize these new institutions, there is a significant body of evidence that they have increased the efficiency of both operations and of capital deployment relative to the earlier systems comprised almost entirely of price-regulated vertically integrated utilities with exclusive service territories.[11] Equally important, they have left most observers and scholars of the electric industry with the conclusion that the only real remaining natural monopoly in the industry is the transmission and distribution function.[12]

The current wave of innovation in DERs appears to be poised to further erode these remaining natural monopoly characteristics of Insull's business model. It may seem ironic that this wave consists of the evolutionary descendants of the reciprocating steam engines and lead acid batteries that his coal plants and transmission lines displaced over 100 years ago. But a century of innovation has produced small distributed technologies that have the clear potential to produce energy at homes and businesses at costs equal to or less than those of central-station power plants plus transmission and distribution systems; to manage both energy production and consumption in a much more decentralized way; and

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[9] By "restructuring" we mean the structural separation of generation asset ownership from the regulated utility and retail choice for consumers.

[10] ISOs and RTOs operate as nonprofit corporations and are legally classified as utilities under the Federal Power Act, except for the entirely intrastate ERCOT (Electric Reliability Council of Texas) ISO in Texas, a not-for-profit organization regulated by the Public Utility Commission of Texas. In regions without ISOs and RTOs, such as in much of the western and southeastern U.S., regional entities carry out reliability-related grid management duties without running wholesale markets and centralized dispatch of power plants.

[11] See, e.g., LW Davis and C Wolfram. 2012. Deregulation, Consolidation and Efficiency: Evidence from U.S. Nuclear Power. *American Economic Journal: Applied Economics*. 4:194-225; K Fabrizio, NL Rose and C Wolfram. 2007. Do markets reduce costs? Assessing the impact of regulatory restructuring on U.S. electric generation efficiency. *American Economic Review.* 97:1250-1277.

[12] More recently, we have seen trends towards the competitive or procurement-based provision of transmission service by specialized, stand-alone firms, again outside of Insull's vertically integrated, exclusive charter, cost-based paradigm. These trends are seen in both new business models such as specialized and merchant transmission companies, as well as in regulatory decisions such as FERC's Order 1000.

with the potential, at least, of also being able to store energy or produce it on demand in a cost-effective manner at a later time.

Today, new business models are flooding the marketplace, capitalizing on the early versions of a number of these technologies and betting on their ability to continue to reduce costs and increase their customer value propositions over time.[13] The erosion of natural monopolies by new business models deploying these new technologies will almost certainly induce additional pressure to shift regulatory policy in directions that will enable those business models. At the same time, regulators will likely seek to preserve cost efficiencies related to any remaining natural monopolies and economies of scope.

c) <u>Other concerns drive a variety of regulatory and policy responses.</u>

Important as natural monopoly is as a foundation for regulation, other market failures and market challenges are often present. Regulation has evolved to address many of them, as well.

For example, universal access to electric service at reasonable rates is widely thought to make society more productive and efficient, suggesting positive social externalities for broad-based access to electric service.[14] Negative environmental externalities due to electricity production are often addressed through both competitive and regulated investments in clean energy resources, many of which are ultimately financeable because of recovery of their costs by regulated utilities from the customers they are exclusively entitled to serve. Transmission and distribution networks have network economies associated with scope and complex coordination processes, with social benefits in terms of safety, reliability, cost effectiveness and universal service.

MARKET FAILURES AND JUSTIFICATION OF REGULATION

The economic policy literature identifies a variety of goods and services whose production entails features that can prevent markets from performing well. These "market failures" comprise four basic categories:

1) Natural monopoly
2) The existence of significant "external" costs and benefits (i.e., due to market transactions that accrue to other parties)
3) Products, goods or services for which it is difficult to define or enforce property rights and which can be accessed and consumed without paying full costs (so-called "public goods")
4) Situations where economic agents have significantly more or better information than the principals who hire them

The equitable treatment of individuals and communities also is a focus of the economic policy literature, although there are different views on whether equity is an economic policy concern or a broader social issue. There are strong arguments that equitable access to public goods and infrastructure networks has both economic and social benefits.

Both economic theory and practical experience have contributed to a relatively standard list of policy prescriptions for how to counteract these key market failures. For example, one authority suggests the primary policy approaches for externalities are to create incentives (e.g., through fees or prices for negative externalities, and through assigning property rights to create revenues for positive externalities) or alternatively, to create regulations limiting firms' ability to create externalities; for public goods, to ensure their non-market supply (e.g., by government action); and for principal/agent problems, to regulate eligibility and performance requirements for the problematic agents (e.g., professional accreditation of accountants and regulation of insurance companies). However, this same source notes that multiple policy solutions are likely and must "be tailored to the specifics of the situation and evaluated in terms of the relevant goals."[1] In the case of utility regulation, this tailoring has involved efforts to address multiple market failures.

Importantly, most policy authorities recognize that government policies, including regulation, are themselves not without costs, and that government action is fraught with inefficiencies associated with rent-seeking behavior, bureaucratic inefficiencies, and the "capture" of regulatory agencies by the very entities they were created to discipline.[1] The cost of these "government failures" should be weighed against the cost of market failures in identifying policy solutions, with the goal of minimizing them both.

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[13] The ability to have electric service independent of the grid does not mean that customers will choose to physically disconnect from it. Many customers may choose to remain connected, even if they have the capability to operate economically independent of the grid, just as many customers with mobile phones also retain their landline telephones. However, the mere ability of significant numbers of customers to disconnect would likely create a "soft" market-based cap on how much utilities can charge their customers for being connected to the grid.

[14] Positive externalities are benefits that accrue to persons outside of market transactions to which they are parties, such as the increased value of all houses on a block when one home's owners paint their house. Negative externalities are costs that accrue to persons outside of market transactions to which they are parties. Markets provide an inefficiently low level of goods and services with high levels of positive externalities, and an inefficiently high level of goods and services with high levels of negative externalities.

These have characteristics of both positive externalities and public goods.[15]

Power sector regulatory and engineering issues are typically complex in a way that exceeds the ability of customers to understand or influence, raising a variety of principal-agent concerns. And there are some aspects of the electric system—such as the reliability and market management activities of RTOs or other reliability authorities—which appear to have strong public good characteristics, in that multiple parties can and do benefit from their services simultaneously and cannot easily be excluded from doing so. As a result, the entities responsible for these activities may not be able to recover their costs in market transactions and indeed typically carry out their missions as not-for-profit organizations.

B. A Framework for Assessing Market Failure and Related Dynamics in the Power Sector and for Evaluating Possible Policy Responses

A broad variety of regulatory and policy approaches have evolved, at both the state and local level and in wholesale markets under federal authority, to address the diverse business models and technology systems in the sector and the variety of market structure and related challenges they create. To better understand how these diverse market structures and policy responses are likely to be affected by a high DER world, we have developed a simple framework that identifies market failure characteristics that are of most relevance in the power sector. This framework allows a relatively straightforward assessment of the degree and type of market failure in various business models and technology systems. It also offers a useful tool for evaluating appropriate regulatory and policy responses that can address changing market implications while continuing to ensure safety, reliability and equitable treatment of consumers.

a) Two main types of structural characteristics affect market behavior in the power sector.

Two key categories of structural characteristics stand out in the electric industry. The first is seen in the wide variety of business and organizational models, which range from heavily regulated monopolies to not-for-profit municipal utilities and RTOs. To us, the defining structural feature of this category is ***potential profitability***, with organizations having strong "public good" attributes (and no potential profitability) at one extreme and those with strong natural monopolies (with very high potential profitability) at the other extreme. Between these extremes are firms within the range of profitability expected in competitive markets.

The second category of structural characteristics can be seen in the equally broad range of degrees of coordination, from individual or small fleets of IPPs and highly competitive providers of distributed generation (with little coordination among them), to extremely large RTOs, vertically integrated utilities and regional reliability coordinators (with high degrees of internal and external coordination). We see the defining feature of this category as the total social benefits—i.e., business plus public benefits—that result, or could result, from enhanced coordination.[16] We call this the ***social benefit of coordination.***

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[15] "Public goods" are goods or services that can be consumed or used simultaneously by multiple people, and which are difficult to withhold or exclude people from consuming or using, such as national defense, the justice system, and roads and highways. This means they are over-consumed and under-supplied in markets, typically because people can be "free-riders"—use the goods and services without paying for them. Determining the right level to charge for a public good is not always easy. For example, it may be most efficient to set at zero the price for a pure public good with zero marginal cost (such as passage on an uncongested bridge), while funding the bridge through broad-based revenues such as highway taxes. Note a positive externality is, in many ways, similar to a public good. A key difference is that public goods can be intentionally supplied directly, while positive externalities are a side effect of activity carried out for some other purpose.

[16] For simplicity, we use the term "integration" both for the physical and financial integration of functions within a single firm, as well as the active coordination of activities among firms by entities such as standard-setting organizations, exchanges and special purpose entities.

Specifically, we consider it likely that firms facing profitable economies of scale and scope face incentives, under competitive pressure in the product and capital markets, will internalize these benefits through integration. Similarly, organizations that can provide more outcomes that are valued by policymakers through coordination will tend to receive policy support to develop such levels of coordination. Further, where profitability or social benefits can be enhanced more by coordination than by actual integration, institutions such as markets, exchanges and standards-setting bodies will tend to evolve to support such coordination through a process that we term *virtual integration*, which we discuss in subsection (d), below.[17]

b) The dimensions of potential profitability and the social benefits of coordination can characterize market dynamics and regulatory response.

We use the ranges of *potential profitability* and of the *social benefits of integration* as the two key dimensions in a simple framework (for simplicity, we will refer to it as the "PPSB" framework). This framework facilitates a two-stage process: first, identifying the underlying structure of market failure characteristics (or their absence) in an industry, and then evaluating appropriate policy or regulatory responses to them.

For example, as Figure 1 shows, businesses with the potential for very high levels of both profitability and social benefits of integration are likely to be strong natural monopolies, while those with very low potential to be profitable but with high social benefits from integration are likely to be large scale providers of public goods. Firms with medium levels of potential profitability and low levels of social benefits of integration are typical of competitive markets.

[17] This concept owes much to Ronald Coase, and in particular to his theory of the firm and its elegant insight that firms grow in scale and scope until the marginal benefits of internal coordination fall below the marginal costs of transacting for the same outcomes in markets. We simply extend this concept to include organizations that provide public goods, and in addition observe that the same logic applies to the evolution of organizations that can provide non-market coordination more efficiently than can be achieved internally through either larger, more complex firms or through pure market transactions. Coase, Ronald H. (1937). "The Nature of the Firm." Economica 4 (16): 386:40.

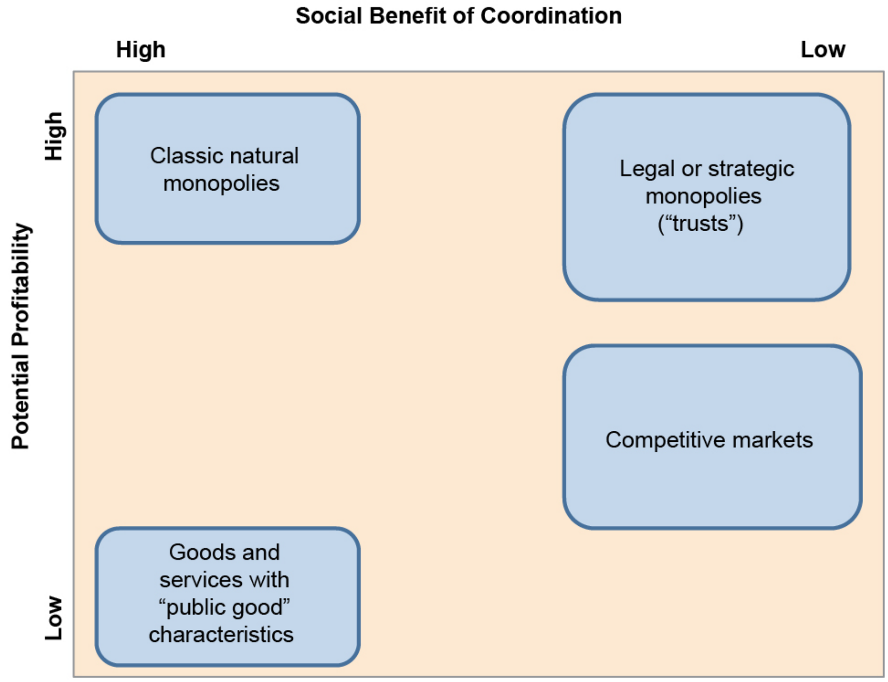

Figure 1. The PPSB Framework.
Potential profitability and the social benefits of coordination (the business and public benefits that result, or could result, from enhanced coordination) capture several key features of industry structure relevant to policy makers. Industry structures that rank high in both dimensions—natural monopolies—are in the upper left corner. Legal or strategic monopolies (e.g., the targets of antitrust laws), ranking high in potential profitability and low in social benefits of coordination, are in the upper right corner. Large-scale public goods are located in the low profitability, high social benefits of coordination space. Competitive markets are located in the medium profitability, low social benefits of coordination space.

Figure 2 shows examples of what we consider to be appropriate regulatory and institutional approaches to each of these basic market characteristics. For example, natural monopolies should be regulated to ensure their potential for low costs are achieved technically, without inefficient monopoly prices and resource use, while organizations that provide public goods should be developed outside of markets but with special attention to efficient operation. Businesses that have medium levels of potential profitability and low social benefits of integration include most competitive firms, and policies should allow free market forces to provide such goods and services.

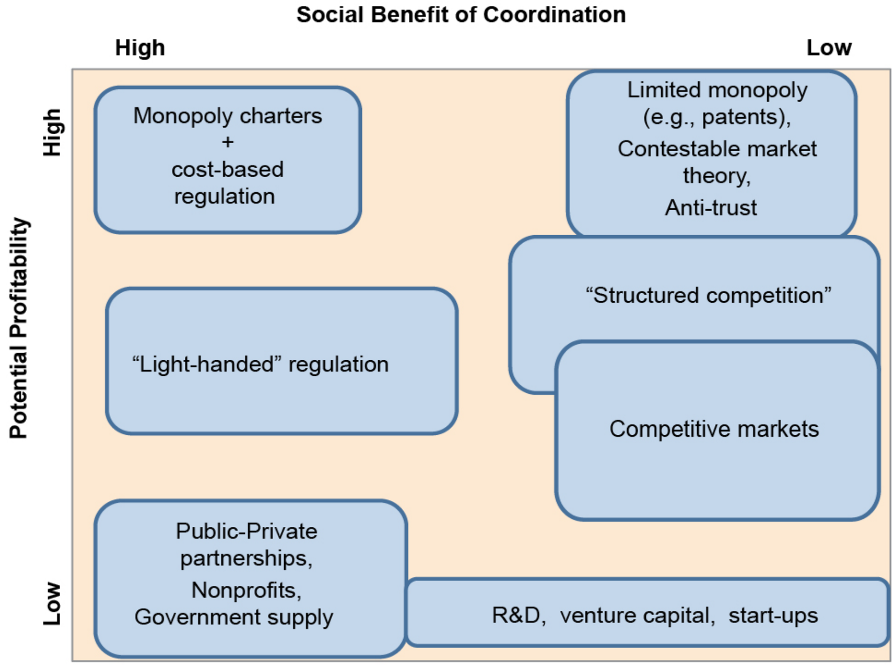

Figure 2. Policy and Institutional Responses in the PPSB Framework.
Policy prescriptions and institutional responses appropriate for various market failures also can be clearly framed using this framework. For example, exclusive charters plus cost of service regulation is often prescribed for classic natural monopolies, which are located in the upper left corner. The lower right hand corner holds various institutions that have evolved to help bring new technologies and new businesses to the level where they can be profitable in markets.[18]

c) Applying the framework to the power sector reveals clear structural shifts.

Figure 3 applies this PPSB framework to key sectors of today's electric industry. What is immediately striking is that utilities and related entities that own or operate transmission, distribution and power market networks are clustered on the left-hand side (with high social benefits of coordination), though with radically different levels of potential profitability. At the same time, the competitive entities in the industry that utilize or (in the case of DERs) could utilize those networks as competitive platforms are clustered on the right-hand side (low social benefit of coordination).

[18] We place institutions such as publicly funded R&D and private venture capital (VC) in the lower right corner because they have evolved to deal with the public good and high risk characteristics of research, innovation and business start-ups, which can combine to limit the commercial viability of new technologies and the business ecosystems that support them. While one could see VC as a sort of market institution itself, we prefer to think of it as an institutional response to the inability of many potentially profitable ideas and start-ups to compete in mature markets. For empirical research on VC profitability, see Diane Mulcahy, "Six Myths About Venture Capitalists," *Harvard Business Review*, September 2013.

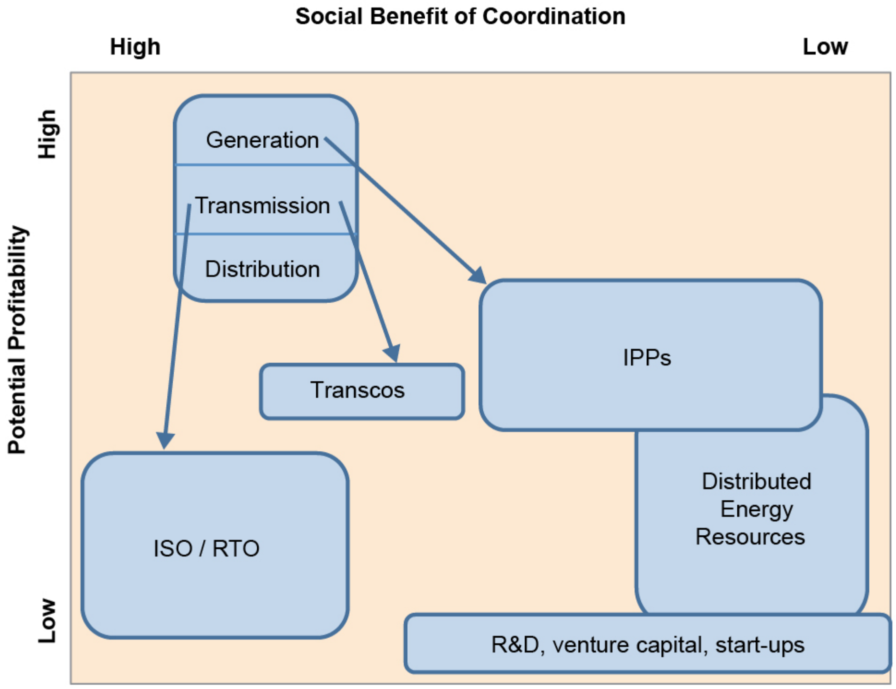

Figure 3. The PPSB Framework Applied to the Electric Sector.
We apply our potential profitability-social benefits of coordination framework to technological and institutional changes in the power sector. For example, the emergence of competitive generation, independent system operators (ISOs) or regional transmission organizations (RTOs) to manage dispatch across multiple control areas, and independent transmission companies and merchant transmission can be seen as responses to more efficient alternatives to strong, multi-product natural monopolies providing generation, dispatch and transmission within exclusive service territories. ISOs and RTOs, on the left, provide a market and operational platform for independent power producers (IPPs), on the right.

Further, the last several decades have seen a pronounced migration from the upper left-hand corner (high levels of both potential profitability and social benefit of coordination) downward and to the right (reduced levels of both of these characteristics), as competitive wholesale markets and lightly regulated transmission companies have attracted generation and transmission assets away from the vertically integrated, legal monopoly structures. Meantime, RTOs and related organizations with limited profit potential have taken over—and significantly expanded—much of the previous function of coordinating dispatch that had been carried out by vertically integrated utilities, as the blue arrows indicate.

d) <u>Virtual integration can serve as a consistent policy response in network industries.</u>

Extending the PPSB framework to other industries shows that it is not unusual for U.S. policies to organize network industries that create high levels of social benefits of coordination as regulated or publicly provided platforms on which competitive industries operate. Figure 4 shows this relationship for a number of other key U.S. network industries and their competitive users, such as transmission owners and independent transmission companies, internet providers and internet-based businesses, airports and airlines, roads and highways and the trucking industry, railroads and freight shippers, and gas pipelines and gas shippers.

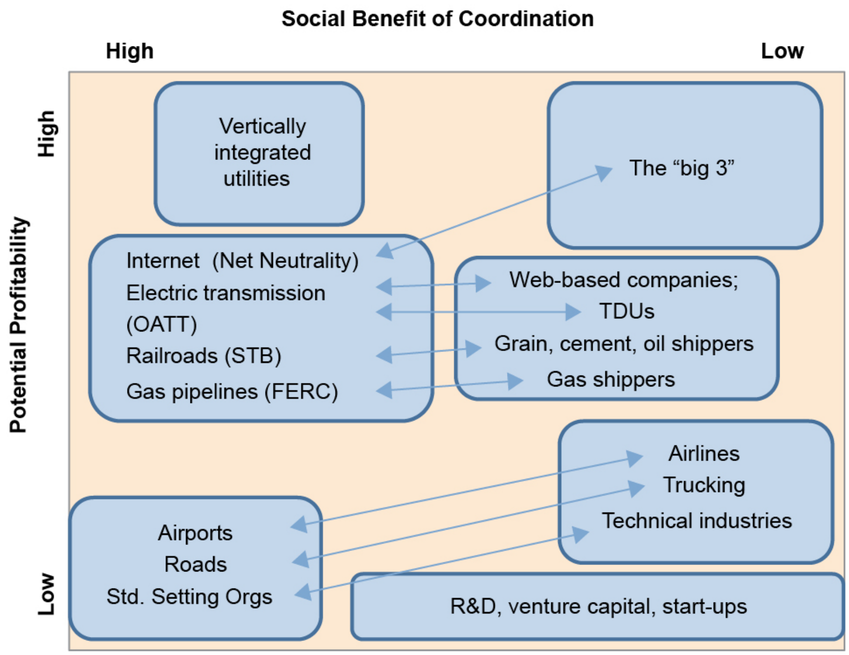

Figure 4. Vertical Integration Across Multiple Industries Illustrated by the PPSB Framework.
On the left side of the potential profitability-social benefits of coordination box are organizations and institutions that provide coordination or platform service for more decentralized companies and industries located on the right side of the box. For example, ISOs and RTOs provide coordination services for competitive generators. Other centralized infrastructure platforms also support decentralized competition and offer a potential blueprint for distribution utilities to serve as a platform for decentralized and increasingly competitive distributed energy resources.

This pronounced pattern suggests that both the U.S. economy and policymakers have repeatedly recognized that there can be strong public and private benefits from what we call *virtual integration* to allow competitive firms to access, coordinate with, and create economic value by using network platforms.[19] The virtual integrators can be for-profit firms (e.g., transmission owners and certain exchanges), nonprofit organizations (e.g., ISOs and RTOs and standards-setting organizations) or quasi-governmental entities (e.g., airport commissions, highway and road departments). In several cases, such as electric transmission and telecommunications, such virtual integration has, over time, replaced vertical integration. In other cases, such as railroads and gas pipelines, virtual integration is weak and to a large degree provided by the regulated network monopolists themselves, who manage logistics and transportation while providing relative flexible pricing under light-handed regulation.

C. Application of Our Structural Framework to a High DER Future

We turn now to an examination of the regulatory implications of a high DER future using the theory of natural monopoly and the insights of the PPSB framework. First, however, we make several key assumptions to focus and inform that examination.

[19] This reflects a striking and much broader societal trend in which various networks—often subject to relatively light-handed regulation or public supply—serve as market-based platforms for the transactions and operation of competitive firms.

a) **Several assumptions are foundational to our analysis.**

- **Competitive DER price and performance levels for many, but not all, customers**
Our first key assumption is that a high DER future results from DERs and related technologies achieving cost and performance characteristics that allow them to provide energy production, management and—to a degree—storage capabilities, at a cost that will make them attractive to significant numbers of customers, though not all customers will necessarily participate in DER market activities. In part, this assumption is based on reasonable estimates of DER potential, which suggest DERs will provide a sizable portion of the total energy resources for the U.S. economy by the year 2030.[20] We believe this outcome is likely, either as an intermediate step in the evolution of DER technologies or as an ultimate end state. We think it is worth analyzing for two additional reasons: 1) the main alternative scenario—DERs never become cost-competitive with utility service—appears unlikely and 2) from a regulatory policy perspective, it is important to prepare for the possibility of a high DER future before it happens.

- **Customer-facing DER deployment dominates**
In addition to assuming that DER prices and performance support significant adoption of DERs, we also assume that many DER products and services will be designed and marketed by competitive firms for deployment by residential, commercial and industrial customers, and that such customer-based deployment will comprise the largest DER market. This means that DERs will be designed primarily to save customers money and improve value of their energy services, while serving secondarily, at best, to provide complementary functions. This assumption has several important implications. First, it means DERs will have many of the characteristics of household and business products in the HVAC, electronics and systems management services markets. We think this is likely based on current trends, but it is also of the most interest from a policy perspective. If most DERs have primarily the characteristics of transformers and other specialized utility equipment, it would be plausible to simply incorporate them into the power sector's supply and delivery functions. Under our assumption, however, it is easy for consumers and their agents to procure and deploy many DERs, and there would often be no cost advantage—and a number of transactional difficulties—for utility procurement and ownership of what are essentially integrated parts of customers' homes and facilities. Such a future is not only likely, but poses new challenges for regulators accustomed to regulating the prices and service quality of monolithic suppliers.

- **Continued policy mandates for reliability, safety, universal access and reasonable prices**
We also assume that regulators and policymakers will maintain strong policy requirements for continued universal access to electricity service, as well as safety and reliability requirements comparable to those of today, and will continue to seek reasonable prices for customers. As with our other assumptions, we think this is both likely and helpful in focusing the policy analysis regarding appropriate regulatory paradigms for a high DER world.

- **Storage cost and performance as "wild cards"**
As noted above, we assume that DERs will be able to produce energy at a cost comparable to that delivered by the bulk power system from large-scale generators. However, the single greatest impact from DERs on the current electric system would come from the development of distributed storage systems that allow energy to be stored in large enough quantities and for long enough periods to allow them to economically replace a significant portion of the capacity function of the

[20] References to base case and "high" DER estimates by the year 2030 are in Appendix A in this report.

bulk power system. Coupled with distributed energy production that is comparable in cost to central station power plants, storage of such magnitude would open the door to widespread consumer defection from the grid. Whether consumers would go through that door in large numbers depends on the degree to which they will receive additional value from remaining connected to the grid.

It is unclear, to the authors at least, whether storage and related technologies will reach cost and performance characteristics that allow large scale grid defection in the foreseeable future. Some analysts believe it is likely and almost imminent, while others argue that only with massive continued innovation and cost reductions will it become even remotely possible.[21] One of the key issues is not only the overall cost of battery technologies, but also whether that cost will be incurred for other purposes (e.g., transportation or resilience), making it much more economical for the battery to coincidentally serve the secondary purpose of providing day-to-day electricity savings. Another issue is whether, even with cost-competitive storage, it would really be in customers' best interest to leave the grid.[22] Further, even highly cost-effective solar plus battery storage technologies may be insufficient to support grid defection in regions with prolonged cloudy periods, without a cost-effective dispatchable distributed generation technology such as micro CHP technologies that combine efficient heating and cooling with electricity production.

Because storage integrates both of the two key products provided to consumers by today's monopoly distribution companies—energy and capacity—we approach the uncertainties around storage using the framework of a multi-product natural monopoly (see Appendix B).

First, we touch on the historic case where the delivery of energy and capacity together by a single firm costs less than producing them competitively through DERs. The strong, multi-product natural monopoly illustrated in Figure 5 captures this situation. The optimal institutional outcome in this case comes straight out of Insull's policy playbook: ensure adequate scale to allow multi-product monopolies to emerge through assigned service territories, and regulate rates to prevent monopolistic price-gouging and undue discrimination among customers.[23]

However, the cost and performance trajectory of DERs is moving in a direction that is already beginning to compete in some circumstances with the utility delivery of capacity and energy. There are a variety of ways this could occur. Figure 6 illustrates one of them, where new technologies deployed by multiple firms can (or could, if the firms entered the market), provide both of the products of the multi-product monopoly at costs lower than any single firm that provides just one of the products, but not below the costs the multi-product monopolist can achieve if it is operating efficiently.

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[21] Rocky Mountain Institute (RMI). *The Economics of Load Defection.* 2015. Available at www.rmi.org.
[22] RMI's *The Economics of Load Defection* report concludes that customer well-being will be enhanced more by adoption of smaller battery and solar PV systems and remaining connected to the grid, than by adoption of larger battery and solar PV systems and defecting from the grid. However, the report also finds that rate-setting policies that are intended to make battery and solar PV users pay large fixed charges to prevent "cost shifting" may actually hasten large-scale defection, by making larger storage systems more attractive.
[23] Note that a natural monopoly for the delivery of capacity and energy is compatible with both competitive wholesale power markets to produce them and competitive retail markets to price them.

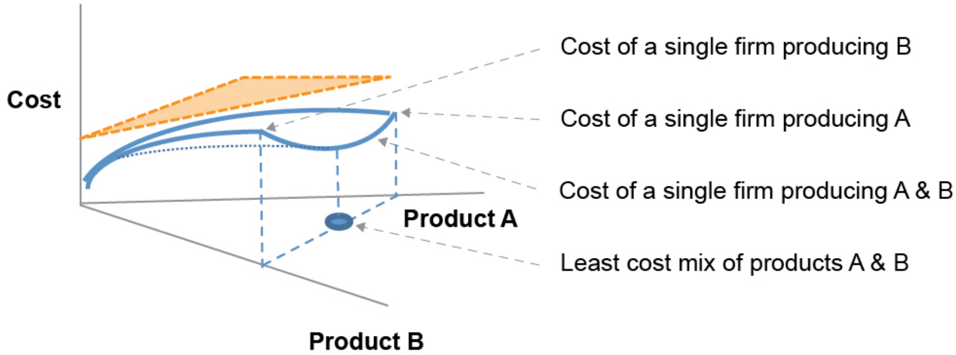

Figure 5. Multi-Product Natural Monopoly.
Multi-product natural monopolies are single firms that have lower costs for producing a combination of products than multiple firms would. Figure 5 shows the total cost (on the vertical axis) of producing various quantities of product A and product B (on the horizontal axes). The single firm's cost of producing a combination of product A and product B is lower than the cost of one firm producing all of A and another single firm producing all of B. The tan plane shows that the cost of multiple firms producing A or B or any combination have higher costs than either of the two monopolists that could specialize in either A or B, and higher costs than the even cheaper multi-product natural monopolist.

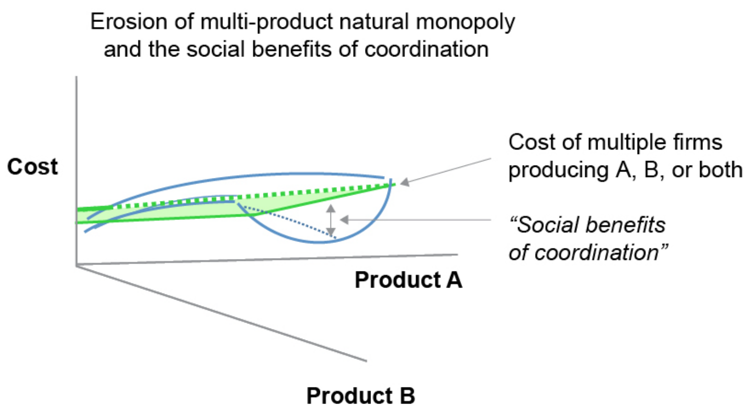

Figure 6. Erosion of Multi-Product Natural Monopoly and the Social Benefits of Coordination.
The emergence of innovative technologies could allow multiple firms to produce either product A or product B at a lower cost (as shown by the green plane) than single firms could, but not at a lower cost than a multi-product monopolist. In this situation, the multi-product incumbent firm may retain its cost advantage and profitably set prices for A and B at levels that prevent the entry of the new technologies. However, other approaches to coordination between the new technologies for A and B may achieve similar or even greater cost savings and other social benefits—collectively, "the social benefits of coordination"—than the incumbent multi-product firm can. If so, this would further erode or eliminate the incumbent's natural monopoly characteristics by providing customers with lower costs through the competitive supply of A and B.

Unlike the historical situation represented by Figure 5, this partial erosion of the multi-product natural monopoly creates significant institutional uncertainty. Three scenarios stand out. In the first, the new competitive technologies simply do not lend themselves to the sort of joint economies that allow the multi-product monopolist to have lower costs. In this scenario, joint production by the multi-product monopolist will remain the least cost option. In the second scenario, the new competitive technologies may be well suited to achieving comparable or even greater benefits with the appropriate level of infrastructure and coordination, and the multi-product monopolist alone possesses the least cost approach to providing that infrastructure and coordination. In the third scenario, the new technologies have characteristics that allow them to achieve comparable joint economies in a more decentralized fashion, without the multi-product monopolist's integration, and offer substitutes for some of the multi-product monopolist's infrastructure.

These three outcomes frame three distinct institutional options. The first scenario suggests society would likely benefit the most from ensuring that the multi-product monopolist's prices are indeed lower than the price of all competing firms, thus ensuring both the lowest production costs for society and the lowest prices to consumers. The second scenario suggests the multi-product monopolist should evolve into the host or integrator of new competitive technologies, in order for society to realize coordination benefits that, in this scenario, only the incumbent multi-product monopolist can supply. The third scenario suggests society will benefit the most from institutional reforms that will enhance the ability of the competitive technologies to coordinate and optimize their interaction in a more decentralized approach, while potentially reducing the capital intensity of the former natural monopolist.[24]

But breakthroughs in storage could further transform the multi-product monopolist. Figure 7 illustrates a scenario where distributed storage is dominantly less costly than delivered capacity (product B), but not competitive with delivered energy (product A). This could arise where a combination of battery technologies and distributed load management provide the ability to meet (or modify) load at a lower cost than wires can deliver firm capacity from the wholesale market, but storage device efficiency and distributed generation technologies are, together, not competitive with delivered grid energy prices.

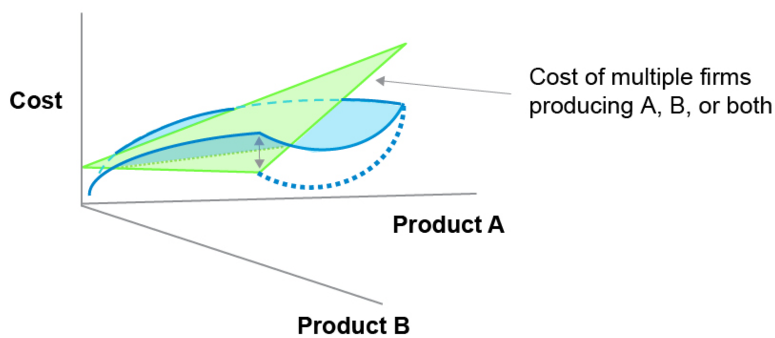

Figure 7. Erosion of Multi-Product to Single-Product Natural Monopoly.
In this figure, new technologies have driven the cost of supplying product B by multiple firms far below the incumbent multi-product monopolist's cost of providing a combination of product A and product B. The green plane represents the total costs of production by multiple firms that supply either product or both. The gray vertical arrow illustrates the reduction in the total cost of product B at full output due to new, competitive supply, relative to the incumbent monopolist's cost of producing it (solid blue line above product B axis). However, it is still cheaper for a single firm to provide product A than for multiple firms to do so, as illustrated by the green plane—positioned above the cost of a single firm producing product A at full output (solid blue line above product A axis). Further, there still may be economies of coordination in production and use of product A and product B (dotted blue curve between the cost of full output of product A and product B). A new institutional approach to achieve these social benefits of coordination is likely once the incumbent monopolist can no longer supply product B at the least cost.

[24] Indeed, several key visions for establishing the "utility of the future"—which we characterize as "get the prices right," "the utility as DER integrator," and "the utility as infrastructure provider and DER platform" approaches—appear to each align with one of these three scenarios. As such, they represent either explicit or implicit expectations about which scenario their proponent either thinks is likely or would prefer to end up in.

As Figure 7 shows, the incumbent multi-product monopolist, to retain its natural monopoly cost advantage, will retrench as a single-product natural monopolist. If we think of delivered capacity as product B in the diagram, this means competitive distributed storage may cause the utility to shrink its investments in delivering capacity—e.g., by investing in fewer and smaller substations and transformers—while continuing to invest in capability to deliver energy to (and potentially among) its customers. Equally important, the question of how to achieve the social benefits of coordination between the fully competitive capacity product and the monopoly utility's energy product is even less clear in this situation.

Regulators will still need to determine appropriate means to support or incent such coordination, even in the extreme case of a fully competitive distributed capacity market, such as would be enabled by major breakthroughs in energy storage. To further complicate the regulatory task, the distributed resources may only be competitive for a portion of the market, raising the important regulatory questions of whether partial monopoly service will be less costly than a full monopoly, and whether monopoly pricing can be sustainable in the face of competition, as discussed in Appendix B.

For the purpose of our analysis, we focus on a scenario where such breakthroughs in storage have not occurred (but also have not been ruled out). As noted above, we also assume explicitly that DER cost and performance are increasingly competitive with both energy and capacity—that is, we are firmly in the world of Figure 6, with ongoing downward movement in the cost of DER technologies expected but its extent not yet fully known. This assumption allows us to explore the key policy implications based on the impacts of DERs on the utility natural monopoly and the broader issues framed by our PPSB framework, including the critical questions of how to support continued social benefits of coordination and attract the capital needed for still essential utility infrastructure during a period when competitive alternatives to utility service are increasingly available. At the same time, this assumption allows us to sidestep the current argument that all that needs to be done to deter DERs is to set accurate cost-based rates—a task that is more ambiguous than it sounds, and increasingly irrelevant when lower cost alternatives are available in the marketplace, as we assume for the purpose of this analysis.

b) <u>We draw several key implications from our analysis.</u>

1. Customers will emerge as key players in the energy system, will be more in control of their consumption and production of energy, and will be increasingly price-sensitive.

DERs will give many consumers the ability to directly manage their energy consumption and energy production, and will allow them to reduce their use or substitute their own production of energy in response to high delivered energy prices. Efficient end-use technologies, dispatchable DERs and storage technologies will allow customers to reduce their maximum connected load. These options will make customers more price-sensitive, or in economic terms, increase the elasticity of customer demand.

2. Price-sensitive customers and alternative choices will put downward pressure on utility costs and risk-taking, inducing new ways to attract capital and allocate risk.

i. Price-sensitivity and DER alternatives limit how much cost can be recovered from utility customers.

The critical result of increasing price sensitivity, from a regulatory perspective, will be a limit on how high utility rates can be set without being self-defeating in terms of failing to collect sufficient revenue. As a result, customer willingness to pay will become a much more significant factor in rate-setting and utility cost recovery.[25] Quite simply, higher costs of providing an "essential" service cannot necessarily be collected from customers if they can readily reduce consumption or turn to other providers in response to higher prices. And simply attempting to fold those lost revenues back into prices through decoupling or lost revenue adjustment mechanisms may not succeed, because high prices are the root of the problem—and higher fixed charges may only induce more adoption of distributed storage technologies.[26]

Because higher rates will not automatically mean higher revenues, cost management will become at least as important to utility managers, investors and regulators as approval of rate requests is today. This will be especially true if the current trajectory of increasing costs for transmission and distribution investment continues.[27] In addition to controlling costs, utility managers, investors and regulators are likely to seek more appropriate ways to allocate the risks of various investments, for the simple reason that higher risks are equivalent to higher costs of capital. Failure of utilities to carefully consider the risk-return tradeoff can lead to financial losses.

ii. DERs can allow the utility to benefit from customers investing their own capital in assets that enhance and augment the distribution system.

We see two ways in which a high DER world can support these objectives. First, customers will invest their own money in their own DERs, but those DERs—with appropriate levels of coordination or virtual integration—can augment the capabilities of the distribution system and even reduce the amount of capital the utility must invest in it.[28] Further, to the extent DER owners and hosts can realize additional value from DER ownership by, for example, providing frequency regulation or voltage support to the wholesale markets and the local distribution system, this leveraging of utility investment can be further enhanced. In effect, by substituting for utility investment, customer DERs can help keep utility revenue requirements within the bounds that increasingly price-sensitive customers will pay for.[29]

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[25] This is another implication of the erosion of natural monopoly. A natural monopoly in a unique product like electricity will typically face relatively inelastic demand as long as the monopoly has major cost advantages over multiple firms that could offer substitutes. If such a natural monopoly invests in assets that increase its economies of scale and scope relative to its competition—as in Insull's Lake County experiment—it will have little trouble recovering its incremental costs and latitude to raise its rates if needed to recover an additional "lumpy" investment. However, once cost -competitive alternatives emerge and start to erode the natural monopoly, the existence of close substitutes at an attractive price will create a natural limit on how high prices can be before customers switch to the substitute product. The risk of exceeding this limit will be further amplified if the utility's additional investment is in assets that increase its average cost, as will be the case with a weak natural monopoly, a multi-product natural monopoly with diminishing economies of scope, or a firm that no longer is a natural monopoly. Thus, regulated utility investment in assets that do not enhance its strong natural monopoly characteristics can be a dangerous path and lead directly to unsustainable rates.

[26] RMI*, id.*

[27] The U.S. Energy Information Administration reports investor-owned utilities spent $14 billion on transmission and distribution infrastructure in 2012, a five-fold increase relative to 2002 levels, with comparably large increases for other utilities: http://www.eia.gov/todayinenergy/detail.cfm?id=17711.

[28] For example, ConEd (a company Samuel Insull helped found prior to moving to Chicago) recently substantially cut the cost of a new substation needed to meet growing load by eliciting proposals for novel, customer-facing distributed energy solutions. This "win-win" solution—slower rate base growth due to customer-facing investments in distributed resources—shows the potential for DERs to reduce costs (and rates) for all customers, not just the DER hosts. See Greentech Media, "New York's ConEd Deferring Substation Upgrades With Demand Management," Sept. 14, 2014. http://www.greentechmedia.com/articles/.

[29] It strikes us as somewhat strange that many utilities seem to want to put DERs in their rate base, despite the fact that they entail substantially more risk than traditional utility assets. One way to explain this is that, as historically powerful natural

iii. ***DERs can help investors stratify risk and de-risk the regulated utility.***

The second way in which high levels of DERs can reduce investor capital at risk, and thus ensure healthier returns for investors, is by stratifying utility investment into lower risk categories. For example, many DERs are likely to entail higher risks of obsolescence due to continued innovation and competition, unlike longer-lived utility infrastructure items such as transformers, breakers and systems for data acquisition. By stratifying competitive investment into the riskier categories, and utility investment into the less risky, longer-lived categories, a high DER world may not only reduce the amount of investor capital put at risk, but also reduce the risk of the investor capital that is deployed. In both ways, a coordinated approach to high DER deployment and optimization can provide more certainty for returning investor capital, and pose less risk of non-recovery from consumers of utility costs they can avoid by simply selecting less expensive alternatives to utility service.

3. ***The high voltage bulk power system will continue to function in a high DER environment much as it does today, with changes primarily in growth, dispatch and approaches to resource adequacy due to high DER levels.***

The bulk power system connects generators with load centers. It is designed to maintain a constant supply of AC power at specific voltages and with other specific characteristics needed for power quality, safety and reliability, and to support the transmission and withdrawal of that power by load at levels that meet or exceed expected usage in each load center. We anticipate that the bulk power system will continue to be needed to supply a significant share of the electricity used in the U.S. economy, and to continue to meet the same safety and reliability standards, even as DERs contribute a growing share. For the purpose of this discussion, we consider generation, grid operations and transmission separately.

i. ***Generation adapts by reaching a new equilibrium between supply and demand, but new market designs and power purchase agreements (PPAs), tolling agreements and procurement processes play an increasing role in controlling costs and risk.***

The primary challenge to the generation fleet from DERs is reduced demand and lower prices. However, the generation fleet can and does adjust to meet lower or higher levels of demand. Older and less economic plants retire and are replaced by newer and more economically robust plants, to the extent they are needed to meet demand or to achieve reduced emission targets. In the absence of technologies that allow large amounts of energy to be stored economically, the primary challenge for the generation fleet in the future is likely to be the need to integrate large amounts of variable renewable energy resources like wind and solar, whether connected to the transmission system or the distribution system.

Under today's energy market designs, such resources will create sustained periods of very low prices at times of maximum renewable energy production, creating the need for evolving

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monopolies, regulated utilities are accustomed to having low risks and thus low cost of capital. A small amount of DERs will only marginally increase the utility's overall enterprise risk, while rate base protection will effectively insulate the utility from the higher risk of the particular DER investment. Thus, initially adding DERs to rate base reduces project risk substantially, while increasing enterprise risk minimally—and potentially delaying competitive DER development. However, as DERs erode natural monopoly status, the utility's entire asset base will become more at risk due to competitive alternatives. The ability of the regulated assets to absorb and buffer DER project risk will diminish, and the impact of large numbers of DERs on the overall risk of the utility will increase. The net effect with substantial amounts of DERs in rate base will be higher enterprise risk in return for little or no buffering of project risk. The higher enterprise risk, if not well managed, will lead to a higher cost of capital, higher rates, and an exacerbated risk of grid defection—the classic "death spiral" feared by investors.

wholesale energy market designs and additional ways to attract capital investment in generating assets—of all types—to a market with chronically low energy prices. The cost-price squeeze discussed above will make it particularly important for utilities to minimize the cost of their power supply, which will lead to an increased reliance on competitive procurement, the wholesale market, and specialized generation firms that can manage cost overruns and performance. Tolling agreements, PPAs and related contracts will become more common in a world where larger revenue requirements and balance sheets do not always equate with higher earnings. In an interesting synergy, such instruments will help finance power plants in the absence of strong energy market price signals, which are unlikely to develop in wholesale energy markets due to large amounts of variable renewable resources, large amounts of storage or both.

ii. Bulk power reliability and operations follow today's practices, with economic dispatch and resource adequacy evolving with DERs.

Bulk power reliability and operations will continue in much the same manner as today, with several exceptions. First, many DERs will function to reduce load at times of higher electricity prices, as part of their primary purpose of reducing customers' electricity costs. In addition, it will be common for DERs to interact actively with wholesale markets, providing not only energy when needed but useful ancillary services as well. This means the bulk power system's dispatch will evolve to include aggregated, interactive DERs, resulting in lower peak loads than in the pre-DER power system.

Second, resource adequacy will be significantly easier to achieve in a world where DERs: 1) allow load to be much more responsive to price and customer value and 2) allow many customers to continue to have self-supplied or locally supplied electric service when grid power is interrupted. Making load dynamically manageable and adding generation on the customers' side of the system reduces the amount of grid-level generation needed to meet resource adequacy standards, and makes the consequences of not achieving those standards less painful.[30]

iii. Transmission impacts are harder to anticipate, but non-transmission alternatives, merchant transmission and specialized transcos will be increasingly important to control cost and risk.

We find it harder to form expectations regarding how transmission fares in a high DER future. On the one hand, ubiquitous cost-competitive DERs should reduce demand, energy prices and volatility, leading to less transmission congestion and reduced need for some transmission projects. On the other hand, the continued need for substantial amounts of grid power and a shift to renewable energy and other low-carbon resources suggests long-range transmission may be more valuable than it currently is for connecting load centers with areas that have competitive advantages in large-scale clean energy resources. However, as with generation, it is likely that the cost-price squeeze utilities will increasingly face as customer demand becomes

[30] Resource adequacy means having enough generation to be able to expect to meet unusually high levels of load simultaneously with unusually high levels of generation outages. The consequence of failing to have adequate resources in real time, as opposed to in expectation, is the need to shed enough load (through mandatory rolling blackouts) to be able to continue to operate the system securely. High levels of DERs mean less load and more total generation available. Thus, the consequences of rolling blackouts will be less severe—if there are enough DERs to achieve the needed load reduction without any mandatory shedding of load.

more elastic will force utility managers, investors and regulators to increasingly explore merchant transmission, specialized transmission firms and non-transmission alternatives.

4. ***Distribution systems will face significant changes in their topology, operation and economics due to high DER penetration.***

The distribution system primarily connects customers with the grid. Its primary role will continue to be delivery of electric service, which consists of two basic products: a) maximum connected load and b) energy on-demand up to the maximum connected load.[31] Like the bulk power system, distribution systems will continue to be needed even in a high DER world to connect customers with the grid and the low cost resources connected to it. But, unlike generation, grid operations and transmission, high levels of DERs will have a more significant impact on distribution systems.

i. ***Conversion from one-way to two-way or multi-directional flows***
Today, most distribution networks are designed to flow power from the grid through radial systems to end users, whose load is determined largely by weather and economic and lifestyle factors independent of the electric system. A high DER environment will change this entire value chain. Controllable DERs will give customers the ability to shift consumption levels and timing to maximize the value of their energy consumption, introduce a higher level of price sensitivity, and allow both production and consumption of power on the customer side of the meter. This will create two-way flows on radial distribution systems, which may impose additional management and design costs on the distribution utility. It will also support the evolution of a multi-directional network design for the distribution system, which could offer additional resilience and customer value, as well as additional costs. Key electrical and engineering parameters of the distribution grid may be affected by DER operation, such as reactive power balance and line voltage levels, system synchronization and integration requirements, and fault clearing capabilities.

ii. ***Storage and cheaper dispatchable resources may shrink the scope of distribution utility natural monopolies and warrant hybrid regulated/competitive distribution systems.***
With cost-competitive storage (or dispatchable distributed generation), the natural monopoly of distribution systems will be eroded and could resemble Figure 7 above. A natural monopoly that faces lower cost market alternatives for a substantial share of its customers would be radically transformed from the powerfully cost-advantaged firms invented by Insull. A natural monopoly facing a market contested by DERs must focus on minimizing its cost, find sustainable prices for serving at least some of the market, and create the maximum amount of benefits of coordination between traditional distribution services and DERs.

In the absence of cost-competitive distributed storage or widespread dispatchable distributed generation, a distribution utility in a high DER future will most likely resemble Figure 6 above.

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[31] Historically, it has only been economically justifiable to install demand meters to measure large instantaneous loads. This has meant large customers typically pay demand charges for their connected capacity costs as well as energy charges. The cost of demand meters, combined with the regressive nature of revenue-neutral, high demand charges, has supported the continued use of volumetric rates for both demand and energy for residential customers. See, e.g., S. Borenstein and J. Bushnell, *The U.S. Electricity Industry after 20 Years of Restructuring,* Haas Working Paper 252R at p. 15. New metering technology may address the cost challenge, but not the regressivity challenge.

That is, the distribution utility will retain a competitive advantage, relative to multiple firms, in terms of being able to connect customers with the single product of capacity (i.e., on-demand power) of the grid, up to each customer's expected or specified maximum instantaneous load. However, even such a natural monopoly will have to focus on cost reductions, sustainable prices and achieving maximum benefits from coordination between its own system and the competitive, customer-facing DERs that can often provide energy at a lower cost than the grid.

It is important to note, however, that as either multi-product or single-product natural monopolies, distribution utilities may well be what economists call a "weak" natural monopoly—a natural monopoly that has increasing costs over part of its output, but has (or at least used to have) lower costs in serving a market than do multiple firms.

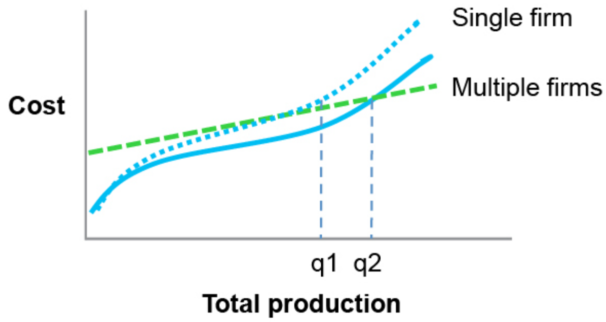

Figure 8. A Natural Monopoly Over Only Part of a Market.
Natural monopolies need not have declining average cost over their entire range of output. Instead, they may have increasing costs over part of their output range, as long as they can produce at lower cost than multiple competitive companies serving the same market. Such firms are called "weak" natural monopolies. Innovation in technologies that can be deployed by multiple firms can reduce the size of the market that can be sustainably served by weak natural monopolies. In this figure, multiple firms using new technologies have costs (green line) that are lower than the monopoly's cost (solid blue line) for output greater than level q2. The least cost and sustainable natural monopoly would be limited to serving up to that level of output. However, regulation itself has costs (dotted blue line), and it may be socially beneficial to scale the natural monopoly back to serving just the part of the market represented by production at q1, where the total cost of competitive supply starts to become less than the cost of monopoly supply plus monopoly regulation.

Figure 8 shows this for the single product case. Here, the solid blue curve shows a single firm's total cost across the scale of the market, and the green line shows the total cost of serving the same market with multiple firms using new technologies. The critical point here is that the distribution system may only have a natural monopoly in serving part of its historical market, due to increasing costs of serving a larger market and the availability of cheaper competitive alternatives on the extensive margin of the firm. In the utility sector, this would be the case where and when DERs offer cheaper alternatives than the utility for serving new markets or providing incremental service in existing markets.

Importantly, the line between the part of the market served by the regulated utility and the part served by multiple competitors may not be spatial—it is perhaps more likely that certain types of investments, regardless of location, would be more suited to being provided by competitive DERs than by additional investment in utility infrastructure. For example, a utility's regulated business would cost less and would more likely be sustainable if competitive DERs (e.g., competitive microgrids or competitive electric vehicle charging facilities) could provide capacity for the part of the market that is more costly for the utility to serve. However, in such cases, the utility may still find it profitable to invest in regulated infrastructure that serves the competitive DERs. In a world where higher revenue requirements do not mean higher earnings, such a hybrid outcome could perhaps represent the optimal situation for all stakeholders.[32]

5. Coordination among customer-facing DERs, the distribution system, and the bulk power system is increasingly important to reduce cost and create value across markets in all three areas.

Regardless of the type of natural monopoly represented by the distribution utility (and even in cases where there may no longer be a distribution utility natural monopoly), the effect of DERs on increasing or decreasing the overall cost of the distribution system, as well as the overall value customers derive from being connected to it, depends to a large degree on the effectiveness of DER coordination. Specifically, what matters is the coordination between DERs' role of (a) creating value for individual customers and (b) their separate but parallel roles of improving the operation and scope of a distribution system, while also (c) contributing to the reliability and efficiency of the grid itself.

As a simple example, consumers can buy smart thermostats to save money while maintaining a comfortable temperature at home or work. Aggregating a large number of such smart thermostats together and using them in a coordinated way can provide thermal load management for the distribution system and demand response-based capacity products for the wholesale electricity market. However, if the aggregator's primary focus is on distribution and grid management rather than on saving customers money while maintaining a comfortable temperature in their homes and businesses, the resulting customer discomfort and lack of savings is likely to stymie the adoption of smart thermostats. If instead the aggregator's primary mission is to save customers money on their electric bills while keeping them comfortable, and only secondarily to optimize the distribution system and provide demand response to the wholesale market, the adoption of smart thermostats could be accelerated while meeting all of these objectives. This would especially be the case if customers are paid a share of the value created by optimization of the distribution system and through wholesale market demand response.

As this example shows, effective and appropriate levels of coordination between DERs, the distribution system, and the bulk power system can dramatically affect the value DERs create in three distinct systems: customers' homes or businesses, the distribution system and the bulk power system. Appropriate coordination of DER utilization will help optimize these three value streams—and will align the customer value that DERs create with their ability to enhance the value of the distribution system itself. This will be increasingly important in a world where high DER levels reduce the sales volume of the distribution utility, and hence its ability to recover additional costs from customers and, for that reason, its ability to attract capital.

Our key conclusions about future distribution systems all reinforce the need for such three-way coordination. In the future, distribution systems will continue to form an essential link between needed grid-scale resources and consumers, but they will evolve to be more dynamic and not only support but be augmented by DERs. Distribution systems also will become more capital-efficient and attract

[32] In the multi-product case shown in Figures 6 and 7, a weak multi-product natural monopoly could have the same shape cost curve as S1 in Figure 8 along each axis. In such a case, it could be optimal for the utility to provide distribution services only to the less costly part of the market and for competitive DERs to serve the rest. It would still be important to create the "trough" of cost-reducing coordination between the two types of products, as Figures 5(a) and (b) show, both for the market served by the utility and for the market served by DERs, through virtual integration of some sort.

customer investments in complementary DERs. In turn, the DERs will reduce distribution costs as well as the cost of the grid and grid-scale generation. Each of these outcomes depends on the increased ability of DERs to respond to grid and distribution system needs in a value-enhancing way, while serving their primary function of creating customer value.

That means that the distribution system and the bulk power system need to be able to communicate their needs to DER owners and hosts, and that DERs need to be able to respond in a way that does not create conflicts between creating value for their owners and hosts on the one hand, and helping out both the distribution system and the bulk power system on the other. How this should best be done is likely to vary by locale, depending on factors such as demographics, local utility costs, and the value that can be created for customers and the system by DERs in the specific locale. For some distribution systems, coordination may best be carried out by the sort of "virtual integration" that we see in many network industries in the PPSB box we described earlier, where the grid serves as a platform for competitive DERs to operate and create value, both for the networks themselves and for customers. We expect that firms that aggregate the management of DERs for multiple customers will facilitate this integration. In other systems, different approaches may be more appropriate. A key question is whether the greatest value can be created by centralized or decentralized coordination of DERs, and whether that centralized coordination is best carried out by the utility itself or by some sort of independent distribution system operator, working with multiple aggregators.

6. A high DER environment requires, and offers, new approaches to attracting capital.

The erosion of natural monopolies in the distribution sector implies a reduction in the profit potential of distribution utility firms, as their sales volumes decline and stand-alone alternatives to both capacity and energy give customers economically attractive alternatives. An even more profound corollary is likely to be the significant increase in the elasticity of customer demand for utility services due to the availability of economic alternatives. For an industry accustomed to highly inelastic demand, this will be a major change. Throughout the utility industry's history, regulators have focused on the challenge of how to keep a natural monopoly facing inelastic demand from charging customers too much, rather than on ensuring their costs can indeed be collected. Utilities, for their part, have always been confident that, if they could get a rate increase approved by their regulators, they could easily collect the higher revenues implied by selling their full output at a higher price.

But in a potential high DER future with economic alternatives and the corollary of more elastic demand, this will no longer be the case. Regulatory approval to charge higher rates will not necessarily mean more revenue in a world with elastic demand for grid-supplied energy and capacity. Indeed, charging such rates might very well lead to reduced revenues and, especially, reduced profit. In the last century's world of inelastic demand and declining average costs, natural monopolies focused on adding assets to rate base and on increasing rate levels when needed to recover the cost of that growing rate base, and investors focused on the likelihood of regulatory approval of needed rate increases. But with elastic demand and increasing average costs, those efforts will be supplanted by new concerns for utility managers, regulators and investors—minimizing the investment at risk in regulated utilities' network rate base, and maximizing the value of those networks to support continued customer and social value.[33]

[33] This shift in elasticity of demand and resulting reduction in the latent market power of the network owner will, if large enough, upset decades of economic and policy thinking about the proper approaches to utility regulation. Thus, this is a key

D. Summary and the Point of Departure for Our Alternative Futures

Our conclusions point towards important structural shifts in the power sector. Increasing customer-facing alternatives to grid-produced energy and capacity will increase the elasticity of demand for these services, limiting and in many cases reducing the profitability of current utility assets. This is consistent with a general movement downwards in the PPSB framework for utilities. At the same time, the economies of scope and coordination that the power sector already is characterized by will increase due to controllable and self-controlling DERs. Indeed, the pressure to reduce costs as potential profitability is compressed will lead investors, regulators and utility managers in search of low cost ways to enhance the social and commercial benefits of this coordination, both in order to reduce utility cost structures and to enhance the value to customers of remaining connected to the distribution system and the transmission system.

The main question we see is whether this integration and coordination function will be carried out primarily by utilities through regulated investment in DER management systems (DERMS) that will allow them to reach into customers' homes and businesses and directly manage and optimize DER utilization, or whether it will be carried out primarily through competitive DER providers and optimizers, who will respond to signals reflecting long-run and short-run needs of the distribution system as a secondary priority, after the primary one of optimizing the value their customers receive from the DERs installed in their homes and businesses. Similarly, we see a variety of ways DER ownership could itself evolve—from a purely competitive market (whether traditional or through a new "sharing economy" approach), to a largely utility-supported set of investments, much as some energy efficiency and demand response assets are supported by utilities today.

As seen through our PPSB framework, this is essentially a question of whether the socially beneficial integration of DERs will take place at the far left hand edge of our PPSB box, internalized to a high degree by utilities themselves, or will take place closer to the middle, either through a new institutional arrangement such as an independent distribution system operator, or through an even more virtual form of virtual integration made possible by smart cloud-connected devices and systems embedded in both the utility's systems and consumer-facing DERs.

We turn now to our two competing visions of this future: one of us (Kihm) assigned to take the view that utilities will play a dominant role in providing DERs to customers as well as controlling DERs and optimizing their use; the other (Corneli) assigned to represent a more market-based, digitally-enhanced approach. Our scenarios may not rise to the level of forecasts, but we intend them to represent coherent, feasible and, in our views, likely results of high levels of DER penetration. In both cases, the setting is the year 2030.

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focus of our analytic framework. We believe proactively avoiding *investment at risk* will become one of the fundamental concerns of utility managers, regulators and investors.

II. A Competitive DER Future in 2030

Steve Corneli

A. Overview of the electricity ecosystem in 2030

Competition in the provision and optimization of customer-facing DERs has dramatically improved electricity services and reduced their cost for all customers. Cost savings and improved performance come from a more efficient wholesale power market, a lower-cost distribution system, and increased use of DERs owned or leased by customers and optimized by competitive third parties to provide their customers with advanced energy services. Importantly, these DERs support the survival and continued vitality of a new kind of distribution utility, both by reducing its costs and by increasing the value DER customers receive from remaining connected to it.

a) <u>The bulk power system is less costly, far cleaner and increasingly competitive.</u>

These changes have not involved radical alteration or the disappearance of the bulk power system. This network of power plants and transmission lines remains an essential source of reliable, safe and affordable power, and the grid is increasingly needed to meet public policy goals implemented by cities, states and the federal government.

Grid power sales to customers are still comprised of the two key products of *energy* (the ability to do work, measured in megawatt-hours or kilowatt-hours) and *capacity* (the ability to produce energy on demand, measured in megawatts or kilowatts).[34] But customers buy far less of both than they used to. This is because DERs have reached a point of cost and performance that is often competitive with energy delivered through the grid and the local distribution system, in addition to managing energy use with great efficiency. High DER deployment has reduced the consumption of both grid energy and, by flattening consumption peaks, grid capacity. Still, grid power remains essential to meet the needs of much of the residential and commercial energy markets, and most of the industrial market.

In response to reduced demand, the wholesale generation fleet has shrunk through the retirement of less economical assets. Growth in generation has focused on replacing uneconomic plants with cleaner, more flexible and dispatchable assets, large amounts of renewable resources, and increasing amounts of utility-scale storage technologies—the vast majority of which are built and operated by competitive generation companies, who can manage the risks of development and performance.[35]

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[34] The production of power on the grid remains complex, with many additional inputs such as volt-ampere reactive (VAR) production and frequency regulation. These ancillary service inputs to power production are still typically bundled into energy and capacity products for sale at both wholesale and retail. Interestingly, however, many DER owners sell such services to both the local distribution utility and to the wholesale grid, while still buying energy and capacity from it.

[35] Wholesale markets have faced a continuing challenge to properly price the many inputs needed for reliable grid service, especially as older dispatchable units in key locations were retired and replaced by variable renewable resources and distributed services. However, over time, wholesale markets have developed better ways to send price signals that induce the investment and operational responses needed to maintain a stable and reliable grid. Still, non-market policy measures such as procurement programs and reliability must-run contracts have sometimes been needed.

b) <u>Distribution system costs have fallen, and the value they offer customers has increased, due to the presence of competitive alternatives to the utility's delivered energy and connected capacity.</u>

Distribution utilities still provide the essential service of delivering capacity and energy from the bulk power system to end-use customers and are still required by law to offer this service to all eligible customers, though, as always, customers may decline to take these services. Distribution systems provide somewhat different versions of capacity and energy than the bulk power system's products, as they have for decades. The distribution system allows customers to tap into the capacity and energy provided by the bulk power system. To help distinguish distribution system services from both bulk power system products and those produced by DERs, these distribution services are now thought of as *connected capacity* (the maximum amount of energy that a customer can draw through the distribution system at any moment from the distribution system, measured in kilowatts) and *delivered energy* (grid energy that can be used on demand by the customer, up to the connected capacity level). Rates for both are based increasingly on economic principles of efficient and sustainable rates.[36] Rates also present customers with appropriate long-run marginal cost signals for both the grid cost of capacity and energy as well as the distribution utility's cost of connecting customers to the grid.

While the cost of DERs is, for some customers, well below the cost of grid capacity and energy, for a substantial number of customers it is still economical to remain connected to the grid.[37] But, even as most customers remain connected, DERs are beginning to substitute economically for a growing share of customers' connected capacity purchases from their distribution utilities. This is because large numbers of customers have adopted DERs—including batteries, back-up generation, and innovative HVAC systems that co-generate heat, cooling and electricity—to provide resilience from bulk power system and distribution service interruptions. DERs are pervasive in new construction and retrofit markets due to their convenience, cost savings, and the increasing number of service interruptions attributable to extreme weather and cyber- or physical-security challenges.

The wide variety of DERs in the marketplace gives customers the ability to produce their own energy, manage its use with unprecedented efficiency, and be assured of continuous electric service regardless of grid or distribution service failures. In so doing, DERs also have given customers an alternative to their utility-supplied capacity and energy, making them much more price-sensitive than in the past. The resulting increased elasticity of demand for electricity puts an upper limit on the amount of revenue utilities can collect by raising rates. The combination of reduced sales volume and competitive limits on the rates the markets for connected capacity and delivered energy will bear resulted in an unprecedented, systemic structural cost-price squeeze for the distribution utility industry. Distribution utilities saw significant revenue erosion and were under tremendous pressure from investors and regulators to reduce their costs and focus on investments that increase the value to customers of remaining connected to the distribution system.

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[36] Natural monopolies are sustainable if there are prices that just recover their cost but are no higher than the prices of competitive alternatives. As early as the late 20th century, economists developed a robust literature on sustainable monopolies and sustainable prices in the context of increasing telephone and intermodal transportation competition. For a comprehensive overview, see Berg and Tschirhart, *supra,* n. 6.

[37] For example, customers with large, constant heating loads and a high need for power quality and continuity have found DERs to be more economical than grid power. Many such customers, however, choose to remain connected to the distribution system and through it to the grid, because of the added value they receive. They can use grid power at times of low energy prices and can sell valuable services to the distribution utility, the grid and, at times, to other customers.

c) **<u>Utilities cut costs and increased the value of being connected to the grid by using customer-owned DERs to avoid utility costs while opening new markets for customers to realize additional DER value.</u>**

Despite significant revenue erosion from this cost-price squeeze, innovative utilities have been able to remain profitable. This has happened for three main reasons:

i. ***Using customer-owned DERs reduced utility costs and increased customer desire to be connected.***

First, utilities and their regulators recognized that, in addition to reducing utility revenues, customer- and third-party owned DERs also can reduce utility costs, both by substituting for costly utility infrastructure such as new substations and underground distribution lines, and by providing lower cost solutions to a host of utility operational challenges such as managing voltage and reactive power on feeder lines. But the benefits received by the distribution utility were not limited to lower costs and healthier margins in the face of reduced revenue. In addition, by giving customers with DERs the ability to realize more value from their DER investments—such as selling ancillary services to the bulk power system and getting paid for improving the distribution system's operations—distribution utilities were able to increase their DER customers' desire to remain connected to the distribution system and to pay their share of the costs of using it.

ii. ***The distribution utility sector has consolidated to reduce cost and maintain profitability.***

Second, the cost-price squeeze from DERs and the need to keep rates for distribution systems below levels where DER users would turn to other sources for energy and capacity have led to a wave of consolidation of distribution utilities. That has allowed utilities to reduce overhead costs and support the proliferation of best practices in maintaining and managing the core distribution system network while maximizing its value to customers. Merger and acquisition activity among investor-owned distribution utilities led to a rapid transformation into a smaller number of low cost, distribution utility holding companies that support and facilitate competitive DERs as a key part of their cost reduction and customer value enhancement strategies. For now, this has satisfied their investors' appetite for growth. Similarly, consolidation and partnerships among distribution cooperatives and municipal utilities have supported cost reductions and greater value creation for customers. Those coops and munis that spearheaded customer-facing DER deployment are leading their sectors. In some cases, cost pressures have led investor-owned utilities to convert to municipal and cooperative ownership structures.

iii. ***Using "virtual integration" has dramatically enhanced the value to customers of remaining connected to the distribution system.***

Controlling costs is only part of the solution to the cost-price squeeze. To keep enough customers who own DERs connected to the system to recover even its reduced costs, utilities have found it essential to increase the value to those customers of being connected. It turns out that the best way to do this has proven to be increasing the value DERs can create, through appropriate coordination for the distribution system and for the bulk power system, in addition to the primary purpose of DERs creating value for the individual customer. The market for this three-way service to customers, the local utility and the grid has led DER providers to dramatically expand the capabilities of a wide range of distributed technologies to provide such benefits.

Consumer-owned DERs can contribute to lower costs for distribution services such as voltage and reactive power control on feeder lines, switchable circuits, thermal limit management and power quality. In addition, DERs can be used or located in ways that reduce the need for larger transformers, breakers and additional circuits. DERs also can provide capacity and ancillary services such as frequency regulation service and ramping to the bulk power system. Distribution utilities and regulators alike have recognized that, in a world of competitive alternatives to delivered energy and connected capacity, it makes better business sense to support customers' ability to capture the additional value streams that DERs create by remaining connected to the distribution system, than for the utility to try to capture those value streams through its own investments in the distribution system. Different states and utilities have created a variety of approaches to carrying out this virtual integration. However, several features have become widespread due to their clear competitive advantages.

The first common feature is the avoidance of vertical integration with respect to customer-facing DERs, involving both utility ownership and utility operational control of them. Utility ownership of both the DERs and the complex DER management systems (DERMS) needed for integrated control increased cost and risk and exacerbated the cost-price squeeze rather than relieving it. The primary problem was the cost of assessing and controlling such a large number of operational units and data through a single vertically-integrated system.[38] In addition, in the few instances where such systems were attempted, consumer acceptance of utility control over household and facility appliances, devices and systems was limited. In hindsight, this seems entirely predictable, because utility expertise is in operating utility systems, not home and business systems, which have seen massive innovation, investment and competition by consumer high-tech companies—including some who were the largest companies in the world at the beginning of the DER revolution—along with large numbers of start-ups, some of whom are now even larger. Thus, competitive ownership of DERs and decentralized, low cost approaches to DERMS have become standard.

The second common feature is relative simplicity of markets and transactions for DERs. Some states and utilities tried to create complex, dynamic locational pricing platforms modeled on ISO and RTO locational energy markets. But a number of these platforms have proven to be so costly as to consume most of the benefits of coordination and to act more as a barrier to using DERs to create value for the distribution utility and the bulk power system than as a way to maximize the value of DER customers remaining connected to the distribution system. Instead, the most successful systems rely on a combination of simple tariffs and technical standards for less dynamic DER values (e.g., avoiding or reducing some of the utility's need for transmission and distribution investments), and automation, predictive analytics, inexpensive internet-based signals to dynamically coordinate competitive DERs with both the distribution system and the bulk power system. What appears to be emerging as best practices is a "keep it simple" approach that fully embodies the need to minimize utility risk, while maximizing reliance on smart analytics and digital systems developed and provided by competitive DER providers.[39]

[38] This problem was foreseen early in the DER revolution. See, e.g., *Smart Inverter Working Group Recommendations*, January 2014, at p. 48 ("Direct control by utilities is not practical nor desirable at this time for the thousands if not millions of DER systems in the field, so the SIWG is using the same hierarchical categorization of DER systems as used to date by international communications experts"): http://www.energy.ca.gov/electricity_analysis/rule21/documents/.

[39] These approaches were championed early by forward-looking municipal and cooperative utilities that partnered with competitive DER providers to create the maximum customer value with the minimum utility cost.

The third common feature among successful virtual integration efforts is support for third-party aggregation and direct interface with the counterparty, whether that counterparty is the distribution utility or a bulk power system-level buyer in the wholesale markets. Efforts to make the distribution utility itself the only intermediary for DER customers failed for the same reasons vertical integration of DERs largely failed—it increased utility costs and acted as a barrier to the innovative, competitive approaches to creating and unlocking value for customers whose "connected homes" and "connected businesses" also remain connected to the distribution system.

d) <u>Capital markets increasingly value utilities on their "Revenue Requirement at Risk" and "System Value to Customers."</u>

In response to the growing awareness of increasing demand elasticity for electricity and the price-cost squeeze on utilities, it is now widely recognized that prudent utility management and prudent regulation alike require attracting non-utility capital to invest in DERs and other assets that minimize utility cost and help maximize the value customers can realize by remaining connected to the system. Given the magnitude of value at risk in the new market structure created by competitive DERs, capital markets have created two new metrics to gauge utility investment and DER policies.

These metrics are now widely used in the valuation of distribution utilities. The first is *revenue requirement at risk* or RRAR, and the second is *system value to customers* or SVC. RRAR measures the share of utility rate base that is invested in assets that could be rendered uneconomic by customer adoption of DERs. SVC measures the net incremental value to customers with DERs that results from remaining connected to the grid. Valuation of distribution utility stocks is increasingly influenced by applying their "SVC to RRAR" multiple to current earnings. In response to pressure from bond rating agencies and equity investors, regulators now use the SVC to RRAR multiple in their cost of capital, ratemaking and planning proceedings.

To minimize RRAR and maximize SVC, distribution utilities have, to varying degrees, reconfigured themselves as platforms to attract consumer and third-party investment in DERs, with special incentives and benefits for those DERs that can minimize the risk utility investors face and enhance the long term value of the distribution network. Appropriate utility incentives for competitive DERs, in terms of location and operations, are a key factor in minimizing RRAR. Regulators, utilities, DER providers and nongovernmental organizations are engaged in ongoing debates about how best to structure these incentives and attract competitive investment in DERs. States themselves are engaged in creative competition for regulatory frameworks that can best attract competitive DER capital and channel it to minimize the cost of maintaining a viable distribution network while maximizing the value of that network to customers.

e) <u>There is no shortage of capital for investment in competitive DERs.</u>

While customers are the primary buyers or lessors of DERs, many of the largest and most innovative firms in the world are competing aggressively to supply them with DER products and services. Competitors include a significant number of Fortune 500 companies with massive balance sheets, including most of the major internet-based companies, the most successful new data intensive start-ups, and a number of traditional energy companies that have entered the competitive, customer-facing world of DERs. Thus, there is no shortage of capital in this new, DER-intensive future. Returns are attractive for companies that succeed in marrying energy market savvy, high-quality customer service, product placement and delivery, and system optimization. Massive amounts of capital can flow freely to DERs as long as they create value for customers—including the value of energy services those customers can sell to their distribution company and to the bulk power system itself, where the growth of variable renewable resources has created vast demand for the controllable load, distributed generation, and various forms of energy storage that DERs provide.

Intense competition and innovation in DERs results in a continual improvement in quality and value of services across U.S. retail markets and demographics. Much of this competition is based on combining DER services with other products and services that are based on the same internet and cloud-based tools, including home security, home health care, information and entertainment, electric vehicle charging, transportation and shopping. Customers face numerous choices. Competition to attract and retain customers is intense, resulting in constant evolution of the bundles, services and packages that create the greatest customer value. Customers have responded by becoming increasingly price-sensitive and increasingly demanding of quality products, customer service and brands.

f) Investors have a clear preference for full separation of utility DER enterprises from the regulated utility.

Early in the DER expansion period, a number of utilities convinced legislators and regulators that they should be allowed to include customer-facing DERs in their rate base and spread their costs across all customers. This practice has faded to a small share of the market and is not seen as a growth opportunity by either utilities or investors.[40] There are several reasons for this. First, adding DERs to rate base had the consequence of both increasing the utility's revenue requirement and putting it more at risk by reducing sales. This was directly contrary to the steps needed to successfully manage the cost-price squeeze created by the proliferation of customer owned and leased DERs. At the same time, investors continued to show more interest in clear and distinct value propositions. Valuation of a single firm that includes both regulated and competitive assets has proven repeatedly to be lower than that of separate firms or clearly differentiated and delineated affiliates. Finally, utility managers and investors alike recognized the value of achieving growth through the cost savings, synergies and scale associated with the consolidation of distribution utilities.

In a more successful approach to capturing growth opportunities from DERs, some of the new consolidated distribution companies have created competitive, arm's-length affiliates to compete in the DER market. They have found that the most value appears to be created by spinning these competitive DER companies off, in whole or in part, through initial public offerings so that they can attract investors with the appetite for the high risk inherent in a constantly evolving, highly innovative and intensely competitive market. Simply put, such risks hold no appeal for the typical investor in long-lived, low-risk utility assets like transformers, wires and breakers. Some of the most successful distribution utility conglomerates have formed partnerships with competitive DER providers to stratify investments in DERs, with the distribution utility investing in the lower risk, durable, long-lived infrastructure assets, and the competitive DER companies providing the higher risk, more competitive customer-facing products and services. This stratified investment has allowed regulated utilities to increase their rate bases and SVC, while decreasing their RRAR. Similar partnerships allow smaller utilities to deploy and manage DERs cost-effectively in markets that may not have the volume to attract full-bore competition among DER providers.

The intense competition by DER providers for customers, and by utility managers for DER-based reductions in costs and increases in the customer value of being connected to the distribution system,

[40] This outcome was foreseen even before the DER boom years. See Pascal Quiry, Yann Le Fur, Antonio Salvi and Laurizio Dallocchio, *Frequently Asked Questions in Corporate Finance*, John Wiley & Sons (2011).

has created widespread benefits. Utility earnings and stock value are up due to dramatically lower costs from synergies of consolidation, the elimination of risky assets from rate base, and the increased value customers see from being connected to a DER-friendly network. Customers continue to enjoy universal connectivity to the grid, but at a lower cost, and with a much more responsive and valuable set of distributed energy services, tailored by the most competitive innovators in the world to each customer's unique circumstances. Investors who like the low risk and solid growth of regulated utility investments have found a way to continue that investment in an era of disruptive technologies and business models, while those who like explosive growth and innovation can invest in a variety of firms that are competing to win in that riskier world.

B. Economic and Market Structure Drivers That Underlie the New Electricity Ecosystem

The new electric power ecosystem and its benefits have not occurred at random or simply because of attractive marketing and messaging efforts. Instead, they are driven in large part by underlying changes in the economics and market structure of the power sector, and in particular for the distribution utility. The policies and regulatory paradigms in 2030 have evolved in response to new technologies with different cost and product value characteristics. In turn, these cost and value characteristics changed the underlying market structure and created new opportunities for customers to improve their lives. These changes allowed entrepreneurs to develop new business models that succeed financially when they are able to deliver better value to customers. Finally, new regulatory paradigms emerged and were refined in the intense competition among states and policy makers to bring the greatest benefits to consumers and constituents.

The key steps in this evolution typically were these: First, the distribution utility had its natural monopoly characteristics eroded to the point where DERs were able to compete with delivered grid energy and provide an attractive alternative to distribution system connected capacity, at least for certain customers. In particular, customers have made large investments in competitive resiliency solutions in areas where frequent storms, fires, or physical and cyber-security threats have resulted in repeated, prolonged outages.

These investments—made primarily for resilience—then allowed individual customers, and sometimes entire neighborhoods or business complexes, to maintain electric service without the utility's connected capacity product and to both buy energy and energy services from, and sell them to, the grid when connected.

Second, some utilities' efforts to limit revenue losses through significant fixed charges for such customers have resulted in dramatically unsustainable prices. As a result, utilities and regulators have learned that a natural monopoly cannot be sustainable if it sets rates for any customers above the cost of alternative providers—especially when the providers offer "plug and play" products at local big-box retailers. As a result, utilities and regulators alike seek cost minimization and sustainable rates. This focus, in turn, leads to increasing deployment of DERs by customers, but in a configuration designed to remain interconnected to the distribution utility. The DER-friendly distribution system creates both purchasing and selling opportunities to help customers find the least cost solution to their energy needs. This involves using the bulk power system and the distribution system that connects them to it, both as a source of cheap energy and as markets for DER customer-provided energy, capacity and related services to help utilities minimize the cost of these systems. Thus, competitive DERs and DER services evolved to support primarily customer value creation and, secondarily, value creation for the distribution system and larger grid.

Similarly, experience and increasingly large amounts of data allowed investors, regulators and utilities themselves to re-examine the economics of 21st century utilities and see that many distribution utilities are, at best, weak natural monopolies with increasing average costs for serving the full scope of their potential markets. Meantime, there were some noted successes in states that were early adopters of regulations designed to reduce distribution system costs by eliciting DER investment. These successes demonstrated that in an increasing cost environment, competitive, customer-facing DER deployment can reduce utility costs, keep utility rates in check, and maintain or improve the quality of service for all customers—while providing greater revenue assurance for the utility.

Finally, the same mixture of experience, data and better theoretical understanding of natural monopoly and market structures has created broad awareness among all stakeholders that coordination between the three roles of DERs—creating value for the DER customer, creating value for the distribution system itself, and creating additional value for the bulk power system—are essential to maximizing the benefits of DERs across the entire power sector ecosystem. A key part of this successful DER future is based on the widespread adoption of various approaches to *virtual integration* as a way to ensure such coordination, without dramatically increasing the utility's costs through ownership of DERs and vertically integrated DERMs to manage them. States are experimenting with these various approaches to virtual integration through a variety of policy approaches, as discussed below.

C. Parties and Roles

This new, highly successful electric industry structure has created a network of value chains that allows customers to interact with competitive DER providers, the distribution system and the bulk power system. This network creates value at all levels, based on clear roles for the various players who transact in it.

a) Key commercial parties

The key parties in these value chains are:

- Owners and operators of resources connected to the bulk power system
- Transmission owners
- Grid operators
- Distribution utilities
- Distributed energy service providers
- Customers

Technology developers and vendors are also highly significant in the supply chains of all these businesses, since it is their innovative technologies that enable a high level of DER deployment and the largely decentralized optimization and control that allows virtual integration to flourish. All of these parties transact in the context of regulation at the federal, state and local level, with regulators at these levels approving tariffs and rules, which in turn determine prices, terms and conditions of service for entities they regulate. The interaction of these parties in the bulk power system has led to a more diverse, but still recognizable industry, along with more significant changes in distribution systems and the approaches to regulating them, as discussed below.

b) A more diverse but recognizable bulk power system

The wholesale side of the business still works much as it did in the "20-teens," with power plants and innovative large-scale storage solutions dispatched in merit order to provide a security-constrained, economic dispatch across large regional markets. Key differences from the first several decades of the century are that a very large portion of the supply stack in these markets is either must-run nuclear, coal plants with carbon capture and storage, combined heat and power, or zero-marginal cost renewable resources. To deal with the large periods of zero-marginal cost energy production and the need for large amounts of dispatchable capacity at times of high demand and low output from variable renewable resources, wholesale market design has evolved to include significant payments to resources with the capability to provide key services such as frequent fast starts and ramping. These payment streams are available to DERs that can respond to wholesale market signals, as well as to resources connected to the bulk power system.

i. Interaction of DERs with the grid creates additional value.

Despite their smaller scale and somewhat higher transaction costs compared to resources connected to the bulk power system, DERs have proven to be highly competitive in the new wholesale markets, largely because the customers who invest in DERs do so primarily for the reduced energy costs and enhanced energy value (e.g., greater resilience and more value from bundled services provided by DERs). Because consumers' capital outlay for DERs is largely compensated by the value of these services, those same DERs can compete in wholesale markets without having to recover their entire fixed cost through wholesale market revenues. This gives DERs a competitive edge in wholesale markets, despite their sometimes higher capital and transaction costs, which in turn has increased their value to customers and their market penetration.

DERs also gain a competitive advantage because of their impact on resource adequacy. As discussed above, a major driver of customer investment in DERs is their value in providing resilience against weather, cyber- and physical security-based interruptions of electric service. These same features mean that DER customer-investors also are able to provide a new level of demand response—namely, to disconnect from the grid at will, while supplying their own electric service. This redefines resource adequacy, essentially by converting what we used to call "load-shedding" to what we now call "economic self-supply" when needed. Not only does this create an additional opportunity for customers to monetize DER value, but it also reduces the need for planning reserves and limits the amount of scarcity pricing that can occur in wholesale markets. Thus, DERs create additional value streams for their customers, while reducing the need for traditional large scale generating resources to assure adequate reserves and resource adequacy.

ii. Impacts on risk and power procurement

The downward pressure on prices in wholesale markets due to increased penetration of renewable resources, more efficient end use of electricity and DERs—along with increasing constraints on carbon emissions due to a combination of federal, state and corporate supply chain performance standards—have significantly altered the market structure and business models for generation. Due to the increased market risk associated with persistent low prices, investors in generation increasingly seek PPAs, tolling agreements and related approaches in order to manage that risk.

This need for insulation from market risk marries almost perfectly with the newfound urgency on the part of utilities to reduce their revenue requirement at risk (RRAR) to prevent customer defection. PPAs, tolling agreements, and various forms of competitive procurement allow utilities and large energy buyers to allocate the risks of cost overruns, missed deadlines, poor execution and poor performance to the competitive entities best suited to manage those risks, and thus to significantly reduce RRAR. Regulated utilities find avoiding these costs and risks important for all categories of assets, including the traditional ones of transmission, generation and distribution, but they have proven to be especially important for new technologies in a changing wholesale market environment. The result is a new wave of contracted or tolled large-scale competitive generation and storage development, which complements the wave of competitive DERs connected to customer facilities at the end of the distribution system. These contracted and tolled generating assets coexist with remaining merchant generator power plants and those owned by vertically integrated utilities, and development of both merchant and utility plants continues where investors and regulators support them.

iii. Grid operations

Grid operations, as discussed in the first section of this report, continue to perform much as they do today to ensure safety, reliability, and consistent power availability and quality at load nodes throughout the U.S. The main changes are the increased utilization of renewable energy and storage technologies, both as large scale resources connected to the transmission system, and as distributed resources connected through the distribution system, where they are complemented by large amounts of controllable load aggregated from millions of homes and businesses.

c) <u>Distribution utilities</u>

The distribution utilities see the greatest changes in their roles in a high DER world. In such a world, the utilities' basic role is to solve the following problems:

1. Connect, or offer connection, to the distribution system for all customers who meet established eligibility requirements,
2. Support the efficient deployment of substantial amounts of customer-facing DERs,
3. Keep the distribution system safe and reliable,
4. Plan, develop and maintain the distribution system to accommodate and support future DER deployment, and
5. Keep the costs of the distribution system and its operation (including overhead) low enough so that all customers can be charged prices (rates) that recover those costs, including the cost of capital, without being higher than the cost of alternative suppliers.

The fifth task is the biggest shift from over 100 years of utility investment practice based on owning and developing assets with strong natural monopoly characteristics. It also is the most critical constraint, because if a utility is unable to meet it—and instill confidence regarding its ability to do so in its investors—it risks losing its ability to recover its costs. This risk, in turn, will increase its capital costs, leading to higher rates and even more difficulty in recovering its costs.

Key steps in solving these problems have proven to be:

1. The constant substitution of customer and competitive DER capital investment for utility investment where doing so will result in lower overall utility cost,
2. Facilitation of coordination between DERs and the distribution system and bulk power system in a manner that maximizes the net benefits for utility customers, including the value that DER customer-investors receive from continuing to be connected to the grid, with the utility enabling customers to adopt various DERs at appropriate levels,

3. Planning of the distribution system and the coordination function to achieve these goals, and
4. Cost minimization in all activities.

d) Distribution system regulators

Distribution system regulators have played an increasingly important role in helping regulated utilities implement these steps and solve these basic problems in a way that maximizes benefits to customers, while giving utility investors a reasonable opportunity to earn a return of and on their investment in assets with enduring natural monopoly characteristics. Regulators now customarily have added the following roles to their previous responsibilities:

1. Regular scrutiny of the underlying cost structure of the utilities they regulate for insights into the extent of natural monopoly, whether it is strong or weak, and the implications for setting of sustainable and efficient rates,[41] encouraging or supporting entry of DERs as a complement to utility service or, in some cases, as a partial substitute for certain aspects of utility service.
2. Evaluation of the potential for utilities to put capital at excessive risk by increasing costs above levels that result in sustainable prices, and the availability of competitive alternatives to better meet those capital deployment needs.
3. Creating transparency and value-producing opportunities for competitive DERs to help utilities avoid risky capital investments, stranded costs and the loss of what may be sustainable natural monopolies through:
    a. Planning distribution systems to minimize utility risk and maximize private investment in DERs, while meeting society's need for increased electrification of the economy,
    b. Supporting customer adoption of DERs in certain locations and with specific characteristics that reduce utility costs or enhance distribution system performance, and
    c. Creating ways to compensate competitive, customer-facing DERs fairly for the value they create for the distribution system, so that DER customer-investors can both lower its cost and realize increased value from remaining connected to it.
4. Leading in the implementation and continual improvement of low cost approaches to DER optimization and control, which allow customers to use their DERs to meet their primary purpose of enhancing the customer's own value, while simultaneously providing valuable services to the distribution system and also supporting easy access for aggregated DERs to wholesale markets where they can sell energy, capacity and ancillary services. As with planning, the goal in DER management and optimization is to facilitate DER customer-investors' ability to lower the costs of the distribution system while deriving more value from remaining attached to it and, through it, to the bulk power system.
5. Develop fair rules for interconnection, operation and optimization of DERs for customers and the competitive DER service industry and ensure the rules are applied in a non-discriminatory manner, along with appropriate tariffs, rates, terms and conditions that support DER deployment while giving utilities a reasonable opportunity to recover prudent costs under appropriate standards (e.g., the "used and useful" standard).
6. Establish clear affiliate interest rules to ensure the full separation of any regulated utility investment in DERs from the balance sheet and operation of the utility, as well as to help enable

[41] Regulators have come to a much more universal appreciation that efficient rates are those that reflect the long-run marginal cost of service, given the time, season and even location where the service is utilized.

competitive neutrality of the utility's role in the virtual integration of DERs and the distribution system.
7. Make high priorities in ratemaking criteria for both sustainable pricing (rates should not exceed either the utility's cost or the price of competitive alternatives) and economic efficiency (rates should be based on long-run marginal cost, not short-run). These criteria are applied in all forms of ratemaking, whether traditional cost-of-service or newer incentive and performance-based approaches.
8. Consider potential benefits of distribution utility consolidation, but carefully scrutinize regulated utility efforts to vertically integrate otherwise competitive DERs into their regulated cost structures and compare to the potentially greater customer benefits of *virtual integration*.

By adding these roles and exercising them thoughtfully, regulators have successfully ensured that the vast and growing pool of competitive capital and innovative technologies that is available to consumers has complemented the regulated utility business model, rather than being limited to an increasingly risky deployment through that business model.

D. A Utility Sector Transformed

These evolving practices have allowed regulators to help the utility industry refocus, after 100 years of pure natural monopoly investment and price regulation, on the emerging reality of ubiquitous capital, multi-company competition, and the transformation of the grid and distribution systems from exclusive monopoly networks to platforms for commerce and customer value enhancement. These forces put regulators and utilities squarely in the role of reducing the cost of the distribution system and the grid and attracting capital from customers and the world's leading companies that are competing to serve them with DERs, while increasing the value of remaining connected to this new, recapitalized grid for all customers—both those who invest in DERs, as well as those who choose not to.

The result of these dynamics is a vibrant new ecosystem for the power sector, in which low-carbon, efficient resources connected to the bulk power system are supplemented by clean DERs connected to customer homes and facilities. Commerce and competition across this ecosystem reduces the cost of both the bulk power grid and the distribution system, while creating much larger markets to enhance customer value across the entire system and driving rapid innovation and value creation in terms of the ultimate products and services customers use.

Indeed, customers—and the mix of world class companies and start-ups that compete to serve them at the lowest cost and with the greatest value—have become major players in the new, clean energy power system. This new, competition-oriented ecosystem has produced broad benefits for society as a whole, especially in states where utilities and regulators have worked together to create regulatory and business models that support competition, innovation and the inflow of capital along with the long-standing values of universal service, affordable rates and prices, and non-discrimination.

Customers who invest in competitive DERs clearly have benefited through lower energy costs and enhanced value from DERs and related products and services. But the lower costs of the entire electric system they have helped create benefits their neighbors who do not choose to invest in DERs. Even broader benefits accrue to the communities brought together by this new, DER-friendly system, to the environment, and to investors of all kinds—those who prefer stable, infrastructure-based returns from investing in new utilities with lower cost and lower risk profiles, and those who prefer the growth and opportunity of innovative technologies and game-changing business models. A growing number of customers are realizing the greatest gains of all by investing in a cleaner, more sustainable energy future for themselves and their families.

III. A Utility-driven High DER Future in 2030

Steve Kihm

A. Utility Responses to Changing Electric Utility Markets

My colleague, Steve Corneli, and I agree in general on the impact of increasingly competitive DERs on wholesale markets, system reliability, and transmission and distribution cost structures. We also concur on basic utility obligations and regulatory responsibilities. I will not repeat his analysis here. The main difference in our perspectives is that he sees distribution utilities playing a somewhat diminished role as DER markets evolve, while I see opportunities for utilities to more actively engage so customers can take full advantage of DERs in meeting society's electric service needs. In my view, under the right circumstances there could be substantial utility benefits from managing DERs. Therefore, rather than being diminished in scope, I see electric utilities keeping pace with industry changes and often leading the pack in that respect. Utilities will have a large role to play in terms of planning the distribution system and providing incentives for DER implementation where those resources are cost-effective.[42] I also expect utilities to form partnerships with third-party providers to facilitate the penetration of DERs.

By 2030 the electric utility industry has lost more load than generally expected a decade and a half earlier. This has created a challenging situation for the nation's utilities. Although a few have faltered, most have responded through innovation and adaptation to implement financially sustainable solutions.

a) <u>Two principal strategies emerged.</u>

Utilities generally focused on one of two strategies in response to the increasing penetration of DERs, although the choices were not necessarily mutually exclusive:[43]

- **The energy services utility (compete with DER providers)** - The utility provides customers with both grid-connected services and DERs.
- **The integrating utility (coordinate DER activities)** - The utility has implemented systems that allow it to control and coordinate customer-sited DERs.

In some cases utilities had a large degree of discretion as to which strategy they chose. In others, the choice was forced upon them either by regulatory action or by market conditions.

There certainly has not been a one-size-fits-all approach. There are significant differences among electric utilities along multiple dimensions. First, some utilities are regulated, some do not have external oversight over rate-setting, and some are regulated in certain aspects, but deregulated in others.[44] Second, some utilities are owned by private investors and their securities regularly trade on the major financial exchanges. Other utilities are owned by their customers[45] or by cities they serve.[46] As such,

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[42] This is in contrast to Mr. Corneli's view that third parties will play a bigger role in this regard. He nevertheless sees utilities being actively involved in the planning process.

[43] This strategic choice—energy services utility versus smart integrator—was set forth by Peter Fox-Penner in *Smart Power*, Island Press (2010). Thirty years earlier, Roger Sant described the energy services utility in his seminal *Harvard Business Review* article, "Coming Markets for Energy Services." The energy services utility concept dates back to Thomas Edison.

[44] See Julia Pyper, "Inside the Minds of Regulators: How Different States Are Dealing With Distributed Energy," *GreenTech Grid*, May 29, 2015.

[45] Rural electric cooperatives are found in all states except Connecticut, Massachusetts and Rhode Island. They are subject to state regulation in 13 of the 47 states in which cooperatives operate, but are subject to *rate* regulation in only seven states. See Jim Cooper, "Electric Co-operatives: From New Deal to Bad Deal?" *Harvard Journal on Legislation* (2009).

some utilities have a profit motive while others do not, although they all have an interest in remaining financially solvent.[47] The third consideration is size. Some utilities are among the largest corporations in the U.S. Other utilities serve fewer than a thousand customers. Fourth, the utilities' physical environments vary from region to region—some operate in states with sunny climates, which make solar PV more attractive; demand response may be most economic in hot or cold climates. Fifth, utilities have different cost structures, which invite competitive resources into some markets, but not into others.

b) Regulators often had considerable influence as to the utility's strategic direction.

One of the benefits of the regulation that applies to investor-owned utilities is the Constitutional protection from inappropriate confiscation of investor capital by administrative agencies.[48] But with that financial protection comes a loss of independence. In many states, as DERs began to change the landscape, the regulator took the initiative in setting the overarching direction for the utility, as was the case in Hawaii in 2014:

> The Commission has not observed sufficient urgency by the utility in addressing this rapidly changing business environment and was compelled to offer this guidance to better align the HECO [Hawaiian Electric Company] companies' business model with customers' interests and public policy goals…. It is now incumbent on the HECO companies to utilize this guidance in developing a sustainable business model that explicitly governs the companies' capital expenditure plans, major programs, and projects submitted for regulatory review and approval.[49]

Even where regulators historically had tended to be more passive, as DER markets rapidly developed in their jurisdictions they were forced to take a position on this matter. Two competing views emerged, largely consistent with the strategies identified above. But the debate in this context was more about the role utilities *should* play from a public policy perspective, not necessarily about the role that best suited utility interests. These matters were not approached lightly as most regulators struggled with them over a period of years. A decision that seemed reasonable in 2017 sometimes lost its appeal by 2021 as electric utility markets changed noticeably over fairly short time periods.

Some parties argued convincingly that as the key player in the electricity market, the utility should actively engage in providing DER solutions to customers as part of their regulated services.[50] But in some utility service areas, third-party DER providers argued that: 1) the involvement of a monopoly utility in

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[46] Some municipal utilities are subject to rate regulation at the state level—as in Wisconsin. Most are regulated by the cities they serve.

[47] The lack of a traditional profit motive does not preclude controversies about subsidies and pricing, especially for electric cooperatives. About 94 percent of rural electric cooperatives offer services in addition to electric service (National Rural Electric Cooperative Association, http://www.nreca.org), some of which are not directly related to the provision of electric service. This, in turn, has led for calls by some to end the cooperatives' tax-exempt status. See W.G. Beecher, "Is It Time to Revoke the Tax-Exempt Status of Rural Electric Cooperatives?" *Washington and Lee Journal of Energy, Climate, and the Environment*, September 2013.

[48] The U.S. Constitution affords regulated utilities the opportunity to earn a fair return on invested capital, not a guarantee. See *Southwestern Bell Tel. Co. v. Public Svc. Comm'n*, 262 U.S. 276 (1923). This Constitutional protection applies only to improper government action. There is no Constitutional protection from economic forces, such as competition. See *Market Street R. Co. v. Railroad Commission*, 324 U.S. 548 (1945).

[49] Hawaii Public Utilities Commission, *Commission's Inclinations on the Future of Hawaii's Electric Utilities*, April 2014.

[50] See, for example, *e21 Initiative Phase 1 Report: Charting a Path to a 21st Century Energy System in Minnesota*, December 2014.

competitive markets violated notions of fair competition and 2) utilities actually had no special knowledge of many DER technologies, undercutting utility claims of their critical importance to the development of the market.[51] Some regulators found these concerns to have considerable merit and in turn precluded regulated utility investment in DERs on the customer side of the meter.

This was the case in New York where in 2015 the Public Service Commission found, "Markets will thrive best where there is both the perception and the reality of a level playing field, and that is best accomplished by restricting the ability of utilities to participate."[52] Some regulators followed the New York Commission's lead in this regard. This added further heterogeneity to utility markets. Not only were there different utility organizational structures—i.e., investor-owned, munis and coops—but even within some categories utilities were on fundamentally different paths.

c) <u>Some utilities that could have competed in DER markets chose not to do so for financial reasons.</u>

As the debate over the proper utility strategy ensued, it seemed to many that, if allowed to implement it, utilities would prefer the energy services model over the integrating option. After all, why should utilities stand idly by and let competitors steal their loads and in some cases their customers? But that turned out to be a more complex proposition than many initially thought.

Successfully implementing an energy services strategy was fairly straightforward where utility costs were low and competition was weak. But it was much tougher where utility costs were fairly high and competitors established a strong foothold. One point became clear over time: Some utilities that originally were able to offer DERs as regulated services had an increasingly difficult time generating the margins necessary to sustain such investment as markets became more competitive. Utilities needed to control their costs and prices, and they recovered the cost of solar PV panels or smart thermostats by increasing their rates. Savvy utility managers thought this through before deciding to enter competitive DER markets under such an arrangement.

The fact was that competing in DER markets sometimes simply didn't pencil out for the utility in a financial sense. While the intrusion of customer-owned or leased DERs limited utility capital expansion, investing in DERs to offset that lost opportunity would represent a value proposition for utility investors only if those investments would regularly earn returns in excess of the associated cost of capital.[53] For example, if the cost of capital associated with DER investments is 8 percent, then the utility would need to expect to consistently earn, say, 9 percent to 10 percent on those investments over the long run to create investor value.[54]

In contrast, if the utility consistently just earned its 8 percent cost of capital on the DER investments, there would be no value gain for investors, no matter how much capital the utility invested.[55] The utility would get bigger, but its investors wouldn't get wealthier. This was not a new idea, as Myron Gordon had explained this in his classic 1974 text, *The Cost of Capital to a Public Utility*: "When the allowed rate

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[51] See James Tong and Jon Wellinghoff, "Should utilities be allowed to rate base solar?" *Utility Dive*, May 11, 2015.
[52] Before the New York Public Service Commission, *Order Adopting Regulatory Policy Framework and Implementation Plan*, Case 14-M-101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Feb. 26, 2015, p. 67.
[53] Tim Koller, Marc Goedhart and David Wessels, *Valuation: Measuring and Managing the Value of Companies*, John Wiley & Son (2010), p. 20.
[54] Arguments about the conditions necessary for investor value creation apply equally to the DERMS investments as well.
[55] Steve Kihm, Ron Lehr, Sonia Aggarwal and Edward Burgess, *You Get What You Pay For: Moving Toward Value in Utility Compensation*, June 2015.

of return is equal to the cost of capital, the stockholders neither gain nor lose when the firm enters a new market."[56]

Executives not only had to convince themselves that competing in DER markets was in the utility's best interest, they also had to convince investors, which often was no easy task.

> A decision to transition to a higher overall risk profile will likely involve significant internal debate and high probability of negative reactions from the financial markets and shareholders. This barrier may ultimately be deemed insurmountable—and as a consequence, new business alternatives may be severely constrained.[57]

Rather than necessarily being the dominant strategy, utilities carefully considered the merits of adopting the energy services approach. Some ultimately proceeded on that path. But a noticeable number of utilities, after some reflection, decided not to do so, even when their regulators would have permitted it. The integrating strategy was the more natural choice for some utilities. It allowed them to play to their strength and offered ample investment opportunity and in some cases a greater likelihood of creating investor value.

d) <u>Efficient utility pricing was necessary, but not sufficient, to deliver the full benefits of DERs.</u>

As competition from DERs appeared on the scene, utilities generally argued that under traditional utility pricing those using certain DERs, especially solar PV systems, were being subsidized by the remaining customers.[58] They proposed substantial increases in monthly customer charges to ensure that all customers paid for their "fair" share of system fixed costs. But others countered by noting that there is no economic theory that supports recovering utility system fixed costs through fixed charges.[59] Some regulatory advisors suggested that the customer charge be limited to the cost of connecting to the grid, which includes only the transformer, the service lateral and the meter, along with administrative processing.[60] Another report in this series evaluates these issues.

It soon became clear, however, that the choice between the traditional rate design, which recovers most fixed costs through a volumetric charge, and the high fixed charge approach, which recovers most if not all fixed charges through the customer charge, was in our modern world a false dilemma. Both are "horribly inefficient" means of recovering utility costs because neither accurately reflects underlying and ever-changing utility cost structures.[61] The key aspect that drives cost causation is the time that electricity is used. No party disputed that.

> To deliver its full benefits, however, the new system must still be managed day by day and hour by hour. That means delivering an effective set of economic price signals to producers and users in the form of more flexible and accurate electric prices.[62]

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[56] Myron Gordon, *The Cost of Capital to a Public Utility*, Michigan State University (1974).
[57] Gregory Aliff, *Beyond the math: Preparing for disruption and innovation in the U.S. electric power industry*, Deloitte (2013).
[58] Jay Morrison and Mary Ann Ralls, *Distributed Generation: Finding a Sustainable Path Forward*, NRECA, 2014.
[59] Severin Borenstein, "What's so great about fixed charges?" Energy Institute at Haas, University of California-Berkeley, November 2014.
[60] Jim Lazar, *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*, Regulatory Assistance Project, April 2013.
[61] Peter Fox-Penner, id.
[62] Peter Fox-Penner, id., p. 39.

The proliferation of advanced metering infrastructure allows nearly all utilities to use some form of time-differentiated pricing. Most utility system fixed costs are recovered not through fixed charges, but rather by some form of volumetric-based peak period prices, consistent with economic principles.[63]

Efficient pricing alone, however, would not deliver the full benefit of DERs to utility systems and their customers. Some utilities procured additional DERs directly. Others coordinated control of DERs, increasing their effectiveness. In some cases, such utility-coordinated control of DERs led to noticeable cost savings. In either case the utility garnered more value from DERs than the competitive markets alone would have produced.

B. The Energy Services Utility (Use the Utility to Procure More DERs)

Although some utilities were not allowed to employ it, and a number chose not to do so, a significant number of utilities, especially the smaller-sized ones, adopted the energy services strategy. Those that did focused on creating value for customers. They managed risks and in the case of investor-owned companies competed in markets only where they believed they could add value for investors, or at least not destroy it.

If markets were perfect, there would have been no need for utilities to enter directly into DER markets. But in our imperfect world, as the electric utility industry transitioned over the past decade and a half, DER markets did not all blossom fully of their own accord. In some locations competitors did not enter utility markets with the same vigor and intensity that they did in others. For example, solar PV providers focused more heavily on serving customers located in areas with higher levels of insolation.[64] Competitors were also less attracted to utility service areas that had low customer densities or where utility costs of service were relatively low. This created a role for many utilities in promoting cost-effective DERs.

Furthermore, even where competition was robust, DER markets tended to be somewhat underdeveloped in a societal sense because typically there were substantial uncompensated system benefits—i.e., positive externalities or public goods aspects that did not flow directly to those who used those resources. (See Part I of this report.) When customers employed DERs in such a way to lower electric use or to add supply, they received economic value in terms of bill savings or payments for services provided. Yet, those actions reduced costs not only for the participating DER customers, but also lowered wholesale-system locational marginal prices (LMPs) and helped utilities avoid future capital outlays. Those benefits accrued to all customers. Thus, the full benefits of employing DERs did not enter the participating customer's cost-benefit analysis, which in some cases led to underuse of those resources. Utilities often filled that gap by providing DERs where they were more cost-effective than traditional supply-side assets.

a) <u>Certain utilities were early adopters of the energy services approach, offering customers a menu of options before significant competition arrived.</u>

Some utilities, especially those that are not subject to substantial regulatory oversight, wasted no time in adopting the energy services model. For example, Wright-Hennepin Cooperative Electric Association,

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[63] Borenstein, *supra*.

[64] *Merriam-Webster* defines insolation as "the rate of delivery of direct solar radiation per unit of horizontal surface." In lay terms, it is a measure of the amount of sunshine an area receives.

which serves the area surrounding Rockford, Minn., has long offered its customers a wide range of services, including the following DERs and other items:

- Access to community solar, with four pricing options for customers to purchase the panels
- Off-peak services for space heating, air conditioning and water heating based on off-peak rates
- Off-peak water heating based on standard rates (The utility provides the water heater free of charge and charges the customer the standard flat rate, while restricting customer use of the appliance to the off-peak period.)[65]
- Direct load control of water heaters
- Energy-saving water kits (low-flow shower head, kitchen swivel aerator, bathroom faucet aerators, plumber's tape and a hot water temperature card)
- Prescriptive and custom rebates for business efficiency upgrades (lighting, HVAC, motors)
- Remote appliance control (customer controlled) for lights, thermostats and appliances (coupled with a home security system)
- A contribution toward the cost of a commercial audit
- Radiant heating systems
- Tree trimming (unrelated to vegetation management for reliability)[66]
- Appliance repair[67]

It was difficult for DER competitors to make inroads against a customer-owned, customer-focused entity like this. The utility essentially won the competitive battle to provide DERs before it really began.

We sometimes dive too deeply into narrow economics when looking at DERs and many other customer choices. The Wright-Hennepin approach provides an alternative narrative. Whether the utility's offerings were less expensive than those offered by competitors was not necessarily the key to the utility's success. In real markets, firms create value for customers by differentiating themselves and their products.[68] Our rigorous economic analysis at the outset of this report helped us to understand why some utilities succeed in offering DERs to customers, while others fail. But the framework loses some of its edges once we consider specific utilities, real products and real customers.

A key component of the successful energy services strategy is relationship marketing, which has emotional as well as economic components. If customers believe that the utility is looking out for their interests, a competitor's deal might have to be substantially better than that which the utility can offer before the customer will choose the competitive option. Note that this is in contrast to the situation for utilities with poor customer satisfaction scores. In that case, some customers may choose competitive alternatives even if they are somewhat more expensive than the utility offers due to their negative view of the utility.[69] Once customer confidence is eroded, it is difficult to rehabilitate it.

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[65] The utility buys power at low, off-peak wholesale rates and charges the customer the higher standard rate. The net margin allows the utility to recover the cost of the water heater it provided at no cost to the utility.
[66] This is landscaping unrelated to any utility service.
[67] Other utilities also offered efficient heat pumps.
[68] Michael Porter, *Competitive Strategy*, Free Press (1980).
[69] In general, customer-owned rural cooperative utilities continued to have the highest customer satisfaction scores in the industry, which made it somewhat easier for them to be successful in implementing the energy services model. See Barbara Vergetis Lundin, "Customer satisfaction with utilities down for second consecutive year," *Fierce Energy*, May 12, 2015. In 2014, on a scale from 1 to 100, cooperatives had an average American Customer Satisfaction Index of 80; investor-owned utilities had an average score of 74; the typical small municipal utility averaged a score of 73.

b) Some utilities developed a customer-hosting approach for solar PV and other DERs.

Other pioneers in implementing the energy services model followed a different path, one that melded supply-side resources and customer locations. CPS Energy,[70] the large municipal utility serving San Antonio, Tex., as well as Arizona Public Service Company and Tucson Electric Power,[71] implemented the concept of "rooftop solar power plants." Participating customers received a rental fee for allowing the utility to place what essentially was a mini-power plant on the customer's property. Rather than providing power to the customer, the roof-mounted solar systems fed the distribution system. As such, while distributed in their location, they were technically on the utility side of the meter. The installations were treated like other system assets, which for investor-owned utilities meant earning a rate base return on the solar panels.

This approach recognized that the value customers associated with certain energy resources was often more symbolic than economic—the customers wanted to employ the resources to demonstrate a commitment to a sustainable energy future. Under the hosting approach, the customer got paid to demonstrate that commitment, which made it quite attractive to many consumers.

c) Many utilities bundled DERs into cost-effective packages, taking advantage of economies of scope.

Some utilities adapted the energy services menu to develop electric service bundles. This was akin to the response of cable television providers to the inroads of satellite TV in the late 1990s. The cable companies addressed this competitive threat by combining their legacy television offerings with internet and telephone service. While the cable companies lost some television customers to the satellite providers, the bundling strategy helped to stem the associated revenue loss. In the first decade of the 21st century, the number of cable television subscribers declined by 13 percent, but industry revenue increased by 117 percent.[72]

The cable bundle was not simply a marketing gimmick. The same cable provided all three services, and the company could provide the connection to all three in the same trip. This represents an example of one of the key concepts we discussed in Part I of this report, economies of scope.

Utilities that were successful in implementing the bundling approach created a utility-customer relationship built on loyalty.[73] The very nature of such relationship marketing rests on the notion of the first term—the relationship. Customers wanted a positive emotional experience with a provider they trusted.[74] Many were more comfortable with the bundle of DER and grid-based services offered by their local utility than they would have been with any package they could assemble themselves.[75] The utilities that succeeded in implementing the energy services bundling strategy understood that many customers were looking for more than simply the lowest sticker price on DERs.

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[70] Tracy Idell Hamilton, "CPS Energy seeks partners for rooftop solar expansion," CPS Energy Press Release, Feb. 9, 2015.
[71] Julia Pyper, "Arizona Utilities Get Approval to Own Rooftop Solar," *GreenTech Solar*, Dec. 26, 2014.
[72] Elisabeth Graffy and Steve Kihm, "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?" *Energy Law Journal*, May 2014.
[73] Chris Parcenka, "Beyond mere customer retention," *Quirk's Marketing Research Review*, March 2008.
[74] Steve Olenski, "This Is the Most Important Word When It Comes to Relationship Marketing," *Forbes*, May 9, 2013.
[75] Graffy and Kihm.

C. The Integrating Utility (Use the Utility to Control and Coordinate DERs)

A large number of utilities, especially those owned by investors, opted for the integrating strategy.[76] Unlike the DER markets, in which the utility did not necessarily have any sort of competitive advantage,[77] utilities had a huge information and technological advantage over other parties in terms of integrating resources. In other words, utilities that adopted the integrating strategy were on their home turf. That is an advantage in any competitive situation. Creating the integration function often led to greater investment opportunities for utilities than were available under the energy services approach. Utilities could create value for their investors just as easily, if not more easily, by investing in information architecture rather than DERs, as long as they balanced risk and reward.

Utilities knew their systems, they knew their customers and they were connected to them. By integrating DER management systems (DERMS) into their larger overall distribution management systems, they could call on customer-sited DERs to balance supply and demand. This allowed utilities to respond not only to general system peaks, but also to locational problems caused by site-specific distribution capacity limits. It was in this localized control and coordination where the real value of a utility-controlled DERMS showed itself.

Utilities had widely varying costs across their distribution systems and only they knew what and where they were. While they could have developed a complex system to send site-specific prices, many utilities found it to be more cost-effective to spend that money on control systems. Price signals were clearly important, but utilities with more sophisticated controlling DERMS squeezed out additional cost savings through direct control of resources. Those systems were expensive, but they delivered substantial savings. And there was often a financial payoff. Utilities were able to earn more than the cost of capital on them when they delivered high levels of system savings, which was often the case, because many regulators had implemented cost-sharing mechanisms. When utilities did a good job in controlling costs, both customers and investors benefitted.

Larger utilities were better able to afford this strategy. Control systems were expensive, and larger utilities had proportionately more customers over which to spread system costs.

D. Successful Utility Strategies

In the face of increasing competition, most utilities have proven to be more flexible and adaptive than many suggested would be the case. The key to their success was that they generally engaged where they had competitive advantages and retreated where they didn't. They carefully invested capital, closely examining risk-return trade-offs. Most important, they strengthened relationships with their customers, creating service options that benefitted both parties.

- **The energy services strategy.** Most of the smaller utilities, predominantly the rural electric cooperatives and the municipal utilities, adopted and successfully implemented this strategy. Success under this strategy resulted from marrying economic concepts such as economies of scope (bundling of services) with a strong dose of relationship marketing. These utilities took advantage of their position in the community and the goodwill they have created among their

[76] The integrating strategy worked for smaller utilities only when they implemented systems of modest scope in keeping with their size.
[77] Some utilities were able to create a competitive advantage by bundling services to achieve economies of scope, as mentioned earlier.

customers. While a strong focus on the customer was essential to success, this strategy worked best where utility costs were relatively low and competition was weak.

- **The integrating strategy.** The large investor-owned utilities were generally the leaders in this arena. Their success was due to careful selection of technology that would create value for their customers and that would produce attractive returns for investors. Utility control of resources through DERMS proved to be invaluable as efficient pricing alone did not deliver maximum benefits available from DERs.

IV. Closing Thoughts

When we started the task of envisioning high DER futures under both a utility-leaning and a market-leaning framework, we knew there was no shortage of passionate and polarized views on the subject. Some of these views are based on extrapolating the utility's historic natural monopoly status into the future, thereby "proving" that utility service would either always be cheaper than DERs or that utilities would be best suited to deploying them. Others seemed to be based on asserting that because some DERs are already priced at levels that compete with current utility rates, the utility's historic natural monopoly status is about to disappear and the utility will therefore disappear along with it.

We were both trained as economists and policy analysts, and both have worked in or with the electric sector for decades, so we found arguments based on simple concepts of "natural monopoly" and "price parity" less than helpful. We felt strongly that we needed to use the basic tools of economic policy analysis and the economic theory of regulation in order to think carefully about a high DER future and its impact on the electric sector and regulated utilities. But we were unable to find an up-to-date, clear and integrated microeconomic approach to think about the relationship between competitive alternatives, natural monopoly and regulatory responses that would apply directly to DERs and the power sector. So we ended up putting together our own tools to aid us in our thoughts.

We have found the most useful of these tools to be the "PPSB box" (Figures 1 through 4) and the basic insights into multi-product natural monopolies provided by the standard economic literature, as reflected in Figures 6 and 7 of our report. The PPSB box helps us think in a more integrated fashion about the impact of basic structural issues—such as natural monopoly, public goods and various externalities—on the conduct and performance of firms and regulation in the power sector. The PPSB framework also allowed us to more carefully consider how high levels of DERs would affect these structural issues and, thus, to better understand which of the relatively standard institutional responses—in particular, new approaches to utility regulation and business models—are likely to produce more efficient and socially equitable improvements under high levels of DER adoption.

While the PPSB framework helped us understand broader structural trends and institutional responses, we found that exploring potential changes in utility business models and regulatory practices required more detailed insights from the economic theory of natural monopoly and its regulation. Essential to our work here are the key characteristics that determine whether a particular multi-product firm is a natural monopoly, and what that really means in terms of appropriate policy responses. The fact that natural monopolies are *per se* defined by the lack of economically competitive alternatives, and that DERs appear likely to offer such competitive alternatives in the future for many of today's utility services and customers, is central to the entire debate.

The economic theory of natural monopoly can be used to generate—and test—propositions about what aspects of the electric system are and are not natural monopolies through careful analysis of utility cost structures relative to the market prices of competitive alternatives. Importantly, the theory of multi-product natural monopolies underscores the importance of economies of scope or coordination to whether a firm is a natural monopoly. It also raises the important question of whether the social benefits of such coordination can be maintained when competitive alternatives erode or eliminate an existing natural monopoly. This takes us back to the lower left quadrant of the PPSB framework, where we observe numerous industries—including the electric sector itself—that have developed institutional frameworks to provide network-based coordination benefits, even when the structure of those networks does not lend itself to cost recovery as a regulated natural monopoly.

Deeper insights, however, came from the process of actually using the tools we developed for this analysis. We started with the view that we were in a debate, and that each of us should try to "win" by proving that either a competitive or a utility-oriented DER future will somehow be best. What we learned by using the tools, however, is that there is an alternative to simply debating this issue. Now, when we think of DERs with cost and performance characteristics that do not deeply erode the utility's multi-product natural monopoly as in Figure 6, we both see distribution utilities responding by moving from the upper left of the PSBB box to its middle left, and we both see the potential of the utility-as-integrator model. When we think of DERs that deeply undercut the natural monopoly's cost structure for both capacity and energy, we both see the distribution utility drifting further down to the lower left in the PPSB box, with less ability to provide a return of and on investments made in private markets and an increasing need for broader-based funding to support the social benefits of coordination that its network will still enable. And we both see the obvious impact of diverse geographical, demographic and cost structures potentially leading to different outcomes for different utilities, even though their customers face the same DER technologies.

But we also see strong common elements in any future with high levels of deployment of DERs that offer even partial alternatives to utility service. In particular, customer demand for utility service will become increasingly elastic as a result of these alternatives. And we both see this increased elasticity of demand putting continued downward pressure on the profitability of distribution utilities, which will force them to continually reduce cost and, at the same time, enhance the value that their networks offer to customers. In this emerging world, we both agree that utility success will depend as much on the opportunities utilities decide not to pursue as on those that they do pursue, and that the ability of regulators to shield the utilities they regulate from competitive pressure will diminish over time.

While these insights align with some of our prior views, they have overturned and significantly changed others. So for us, the biggest insights of all are these: As Sam Insull showed us, regulatory and institutional structures respond to facts as well as to passionate vision and effort. As DERs become more competitive, that fact alone will increasingly override the dominant role of the utility and reduce the ability of regulators to influence the utility's financial health. It will increasingly be up to the utilities themselves to make business decisions that will enhance their customers' well-being while acting as responsible stewards for the capital entrusted to them by their investors. Now is the time to carefully anticipate and prepare for the impacts of competitive alternatives on traditional utility services, business practices and their regulation. As we hope this report shows, appropriate analytical tools can help utilities, DER providers, regulators and policy makers identify appropriate responses to emerging patterns of facts, as well as to conflicting visions and efforts. Such tools can allow us all to move quickly from polarized debate to the informed development of insights and to take advantage of today's crescendo of innovation to help solve the critical problems facing the electricity sector, to the great benefit of society as a whole.

Appendix A. High Distributed Energy Resources Scenarios

This report, and several others in the Future Electric Utility Regulation series, explore the potential impact of a significant increase in the use of distributed energy resources (DERs) on both the physical electric system and the institutional arrangements surrounding it. These resources include:

- Energy efficiency
- Demand response
- Distributed generation
- Distributed energy storage

Technological and procedural innovation and advancement are leading to substantial reduction in the cost of some of these resources. For example, the installed cost of solar PV continues a long-term trend downward.[78] This report does not rest on the notion that a high penetration of DERs is necessarily the best outcome from a public policy perspective. It takes a high DER scenario as a given and analyzes possible implications.

There is a wide range of forecasts of the potential for DERs over the coming decades, some of which suggest that penetrations could be significant. For example, Navigant's base case analysis of the states in the Eastern Interconnection suggests that DERs will supply 19 percent of the required capacity (MW), compared to 11 percent today.[79] In contrast, the Western Electricity Coordinating Council's high penetration scenario[80] has DER penetrations at 37 percent by 2032. These estimates have been made on somewhat different bases. See the source documents for details. The following table provides capacity levels for these scenarios.

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[78] Galen Barbose and Naim Darghouth, with contributions by Dev Millstein, Mike Spears and Ryan Wiser (LBNL); Michael Buckley and Rebecca Widiss (Exeter Associates); and Nick Grue (NREL), *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*, Lawrence Berkeley National Laboratory, Report No. LBNL-188238, August 2015, https://emp.lbl.gov/publications/tracking-sun-viii-install.
[79] Navigant Consulting, Inc. *Assessment of Demand-Side Resources Within the Eastern Interconnection*, March 2013, http://bit.ly/EISPCdsr.
[80] Western Electricity Coordinating Council, *SPSC Study High EE/DR/DG*, Sept. 19, 2013, https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2032_HighEEDSMDG_StudyReport.docx&action=default&DefaultItemOpen=1.

Estimated Distributed Energy Resource Penetrations
2015 vs. 2030-2032

	Percent Capacity (MW)		
Resource	**2015**	**2030 Eastern (base case)**	**2032 Western (high penetration)**
Energy efficiency	1.9%	7.4%	21.5%
Demand response	5.5%	5.4%	3.3%
Energy storage	0.0%	0.3%	N/A
Distributed generation-natural gas	2.6%	2.5%	N/A
Distributed generation-renewable	1.0%	3.4%	9.4%
Combined heat and power	N/A	N/A	3.3%
Total DERs	**11.0%**	**19.0%**	**37.5%**

Sources: Western Electricity Coordinating Council, SPSC Study High EE/DR/DG, Sept. 19, 2013;
Navigant Consulting, Inc., *Assessment of Demand-Side Resources Within the Eastern Interconnection*, March 2013.

Some DERs already have achieved noticeable penetration. For example, FERC reports that demand response currently eliminates 9 percent of the nation's capacity peak.[81] Even though energy efficiency programs have been in place for decades, the potential to continue to capture large amounts of additional energy efficiency is well documented. McKinsey & Co. estimates that efficiency gains could reduce U.S. electricity use by up to 20 percent by 2020.[82] Other DERs have significant ramp-up potential. DOE's SunShot Initiative expects distributed solar PV to supply 9.1 percent of U.S. energy capacity (MW) by 2030.[83] Under a high-penetration study, one utility, PacifiCorp, could add as much as 2,500 MW of solar PV over the next 20 years, about 25 percent of its current generating capacity.[84] ICF International estimates economic potential in the U.S. for an additional 42 GW of combined heat and power systems, primarily natural gas-fired, under current conditions, and up to 63 GW under more favorable conditions (e.g., higher electricity prices).[85] These figures represent 4.0 percent and 5.9 percent of total U.S. generating capacity.[86] Energy storage will likely provide only small amounts of capacity in the near term (0.03 percent in 2018),[87] but could be a significant resource by the end of the next decade. Forecasts suggest that it may cost less on a life-cycle basis than even the lowest-cost generation source.[88]

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[81] Lee, M., et al., *Assessment of Demand Response and Advanced Metering*, FERC Staff Report, December 2014.
[82] This is an estimate of economic potential. Achievable potential would be lower. McKinsey & Co., *Energy Efficiency: A Compelling Global Resource*, 2010.
[83] *Sunshot Vision Study*, 2012, Energy Efficiency & Renewable Energy (EERE). NREL Report No. BK-5200-47927; DOE/GO-102012-3037, http://www1.eere.energy.gov/solar/pdfs/47927.pdf.
[84] High-DER scenario estimate: K. Corfee et al., *Distributed Generation Resource Assessment for Long-Term Planning Study*, Navigant, Inc., June 9, 2014; current capacity: http://www.pacificorp.com/es.html.
[85] B. Hedman et al., *The Opportunity for CHP in the United States*, ICF International, May 2013.
[86] The Energy Information Administration lists U.S. electrical generating capacity from all sources in 2013 as 1,060 GW. http://www.eia.gov/electricity/annual/html/epa_04_02_a.html.
[87] R. Manghani, "The Future of Solar-Plus-Storage in the US," GTM Research, Dec. 18, 2014.
[88] See M. Fuhs, "Forecast 2030: stored electricity at $0.05 per kWh," *PV Magazine*, Sept. 26, 2014, and U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

Appendix B. The Economics of Natural Monopoly

A firm that can supply an entire market at a lower cost than any combination of competitive firms is said to be a natural monopoly. Technically, this means the firm's costs will be less than the sum of the costs of multiple alternative firms, a condition economists call "sub-additive costs." For simplicity, we will first consider a single-product firm, that is, a firm that makes just one product such as electricity or rail service.

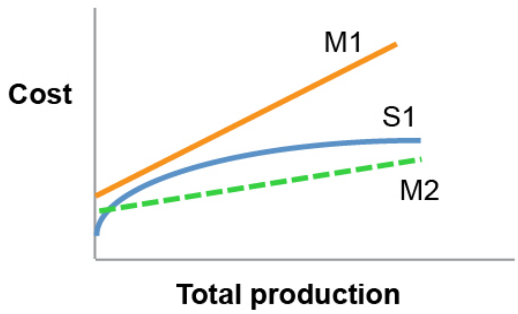

Figure A1. A strong natural monopoly (decreasing average costs)

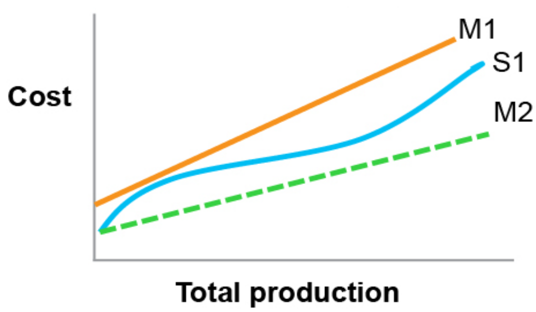

Figure A2. A weak natural monopoly (increasing average costs)

A single firm with sub-additive costs can have either decreasing average costs over its total output (see line S1 for a single firm in Figure A1), or average costs that increase over part of the range of its total output (line S1 in Figure A2). These purely illustrative graphs show the quantity of the single product produced by the monopoly on the horizontal axis, and the total cost of producing that product on the vertical axis. The average cost of a given amount of output is total cost divided by output, so decreasing average costs are revealed by a total cost curve which, like line S1 in Figure A1, increases at an ever diminishing rate as production increases. In both cases shown above, the firm is a natural monopoly, not because of the curvature of its cost function, but because it can produce the one product at a lower cost by serving the entire market than multiple, smaller firms could, as shown in each figure by the line M1, which represents the total cost of serving the market with multiple firms. These illustrative graphs indicate the key features that create a natural monopoly—both the natural monopoly's own cost structure and, equally important, the cost structure of multiple firms that do or could supply the same goods and services. Different products and markets will have different cost characteristics for both the single firms that may be natural monopolists and the multiple firms that compete, or could compete, with them. However, regardless of variations in cost structure and product, a firm is only a natural monopoly if its cost of serving a particular market exclusively is lower than the cost of multiple firms serving the same market.

If a firm is a natural monopoly, the shape of its cost function can make an important difference in how it should be regulated. A single firm with declining average costs everywhere, as in Figure A1, is termed a "strong" natural monopoly. A firm with a mix of declining and increasing average costs, as in Figure A2, is termed a "weak" natural monopoly. In either case, the firm with the sub-additive costs is a natural monopoly, simply because its cost is below the cost of multiple firms meeting the same market demand. Society will typically pay less for the product and ensure its inputs are used more efficiently if a single firm is allowed to serve the entire market. But efficiency also requires that firm be constrained by regulation to produce enough output to meet the entire market's demand and to set prices at cost, much as Insull advocated in 1897.

Natural monopolies, however, are not fixed or permanent. If innovation in technologies allows multiple firms to serve the entire market with the same product (or a close substitute) at a lower cost, the natural monopoly disappears, even though the single firm retains the same cost structure. In Figures A1 and A2, the dotted line labeled M2 illustrates the emergence of multiple firms using such technologies. The single-product natural monopoly will disappear along with its profits, all customers will receive lower cost and/or better quality service from multiple firms, and the monopoly's assets will be turned to some secondary use or consigned to Insull's "junk pile."

Not all natural monopolies produce a single product. Distribution utilities can be thought of as producing multiple products rather than just one (e.g., the delivery of both capacity and energy, or service to multiple classes of customers). Natural monopoly in the multi-product firm requires not only sub-additive costs for each product, but additional economies of scope in supplying the two products by one firm. Otherwise, it would be less expensive to have two separate regulated monopolies provide the two products separately.

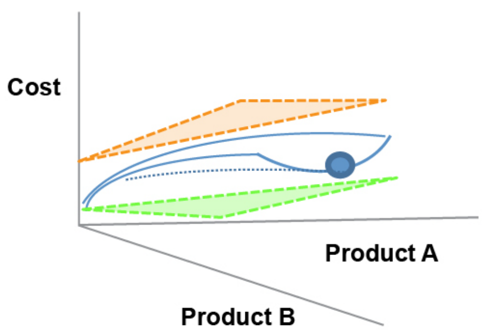

Figure A3. A strong multi-product natural monopoly

Figure A3 illustrates such economies of scale and scope for a single firm producing two products, A and B, with a concave "trough" formed by the solid blue lines. The curvature of the blue lines above the product axes illustrate economies of scale, the curvature of the blue line between the axes shows economies of scope in producing combinations of the products. The figure shows that a single firm for this hypothetical mix of products A and B will have lower costs (producing the mix at the blue dot) than multiple firms whose costs are represented by the orange plane. Due to the economies of scope, the single firm also has lower costs than separate monopolies for each product. Note, in this case, the natural monopoly's low cost allows it to serve the entire market at a lower price than multiple firms could. The blue dot indicates that the firm has a lower total cost than any combination of the same amount of multiple firms' products on the orange plane. As in the single product case, the emergence of new technologies that can be deployed at lower cost by multiple firms (the green plane) would eliminate the natural monopoly and allow multiple firms to better serve society's needs for the same products or services. In this case, the role of policy is to ensure a smooth transition to the new technologies, business models and market structure.

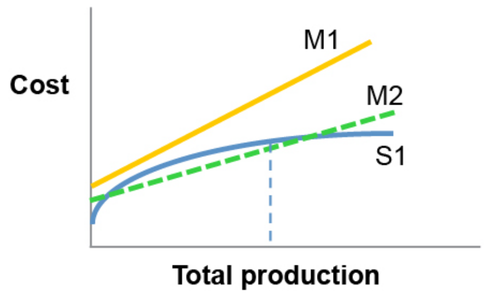

Figure A4. A potentially sustainable, strong natural monopoly

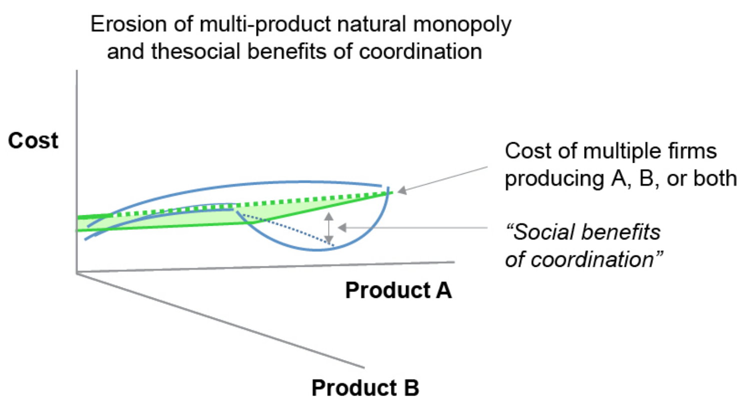

Figure A5. Erosion of multi-product natural monopoly and the social benefits of coordination

A number of intermediate cases seem likely in a high DER future and offer significantly greater policy challenges than the complete elimination of a natural monopoly. For example, innovative new technologies may have total cost curves like those shown in Figures A4 and A5. In both of these cases, innovative technologies allow multiple firms to have lower costs than the natural monopoly over levels of output that could satisfy some of the market, but not all of it. In Figure A4, the natural monopoly can still serve the entire market at a cost below that of multiple firms, but multiple firms may be able to out-compete the monopolist for small segments of the market to the left of the vertical dotted line. In Figure A5, multiple firms can produce either product A or product B at a cost below that of a single monopolist producing either product, but may not be able to replicate the economies of scope or coordination enjoyed by the multi-product monopolist.

The potential for new technologies to compete for a portion of a natural monopoly's customers raises the question of whether the natural monopoly is sustainable. Economists call a regulated natural monopoly *sustainable* if there is a set of prices (rates) for all customers that are all no higher than the competitive prices offered to any customer, and that still just cover the utility's cost. By contrast, natural monopolies are *unsustainable* if the loss of some customers to lower, competitive prices cannot be prevented without raising prices above the utility's cost for other customers, inviting competitive entry or pricing above efficient levels in that market as well. This leaves regulators with the difficult choice between (a) preventing subsets of customers from buying cheaper alternatives that are available in the marketplace or (b) losing the natural monopoly's remaining cost advantage (which may be relatively small) in serving the entire market.

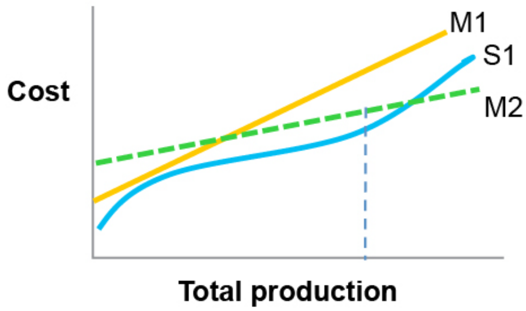

Figure A6. A potentially sustainable weak natural monopoly

In Figure A6, the new technologies have evolved to give multiple firms a cost advantage (green line) over the weak natural monopoly for a substantial part of the market. However, the single firm can still serve the entire market to the left of the vertical dotted line at a lower cost, net of the cost of regulation itself, than multiple firms can. This creates the opportunity for regulators to reduce total costs by restricting the regulated natural monopoly to serve the smaller market to the left of the dotted line, where its total costs are still lower than those of multiple firms, while at the same time inviting or soliciting competitive DERs to serve the rest of the market. Such use of competitive DERs to avoid or reduce the cost of expensive new facilities is contemplated in the New York REV proceeding, and it appears to be actually happening in practice with regard to Consolidated Edison's Brooklyn Yards substation project.[89]

At the same time, some believe that utilities themselves, under appropriate forms of regulatory reform, would be best positioned to deploy the new technologies and add them to their rate base. A key question for policy makers in the weak natural monopoly case is whether utility ownership of DERs will increase or decrease the utility's ability to offer sustainable prices in the long term.

Regulators of multi-product natural monopolies face similar challenges. In Figure A5, we saw how innovative, stand-alone technologies could completely displace the single-product natural monopoly characteristics of both Product A and Product B, but not replicate the multi-product natural monopoly's economies of scope between the two products. This means multiple firms could supply both products at far lower cost than two stand-alone natural monopolies, but significant cost savings could still be sacrificed without means to coordinate the production or delivery of these products as well as or better than the multi-product monopolist can. This leaves regulators with the difficult choice between attempting to prevent the entry of new, more efficient technologies in order to maintain the coordination benefits of the existing natural monopoly, or allowing entry and fostering the creation of a new sort of organization to create or even improve the benefits of coordination. For simplicity Figure A5 only illustrates strong multi-product natural monopolies, but the challenges of both weak natural monopolies and sustainable prices exist for multi-product monopolies as well.

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[89] See n. 32, above.

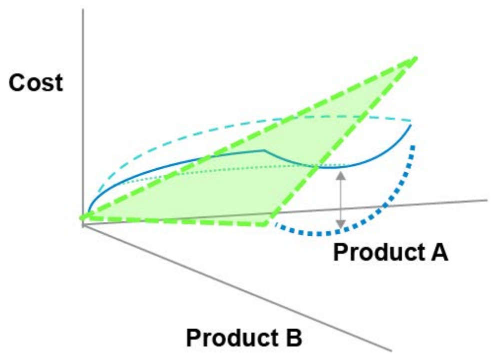

Figure A7. Multi-product to single-product natural monopoly

In Figure A7, new innovative technologies allow Product B to be dominantly supplied by multiple firms, but a single product monopoly is still the least costly way to supply the entire market with Product A. In order to retain economies of scope, regulators may be tempted to allow the erstwhile multi-product utility to raise prices above cost for customers of Product A and use the extra revenue to subsidize the cost of selling Product B below cost. This approach is likely to be suboptimal—pricing above cost and misallocating resources in the market for Product A can hardly justify pricing below cost and creating barriers to entry for cheaper competitive products in the market for Product B. Instead, regulators should seek to ensure efficient prices for Product A in the remaining natural monopoly market, while nurturing virtual integration to coordinate the utilization of competitively provided Product B. Indeed, it may be possible to minimize the cost of such virtual coordination by incentivizing competitive investment and services to provide the majority of it.

Note that the regulatory paradigm of achieving enhanced economies of scope through virtual coordination between former natural monopolies (e.g., for generation) and smaller remaining natural monopolies (e.g., for transmission) through the creation of new organizations (e.g., ISOs and RTOs) appears to be well established. Calls for distribution system operators or distribution platform providers can be seen as efforts to create such virtual integration between competitive DERs and the integrated distribution provider.