Modernizing the Electric Distribution Utility to Support the Clean Energy Economy

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List of Acronyms

DER	distributed energy resources
DG	distributed generation
DOE	U.S. Department of Energy
DRP	Distribution resource plan
DSM	demand-side management
DSO	distributed system operator
DSP	distributed system provider
EE	energy efficiency
ESCO	energy service company
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GMP	Green Mountain Power
IOU	investor-owned utility
IRP	integrated resource planning
ISO	independent system operator
kWh	Kilowatt-hour
MW	Megawatt
NEM	net energy metering
NMPC	Niagara Mohawk Power Company
NSP	Northern States Power
NYPSC	New York State Public Service Commission
PBR	performance-based ratemaking
PNJ	Pennsylvania-New Jersey Interconnection
PPA	power purchase agreement
PSB	public service board
PUC	public utility commission
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
PV	photovoltaic
REV	NYPSC Reforming the Energy Vision process
RTO	regional transmission operator
VOS	value-of-solar
WWI	First World War

Abstract

The purpose of this paper is to provide policy makers and stakeholders with analysis-based options for the future of the regulated electric distribution utility. The electric industry, no longer focused solely on improving and selling services to its customers, is making shifts unimagined just two decades ago, such as supporting a transactive role for customers based on clean energy technologies.

The development of a transactive energy system is already under way. The result of this system transition is increased complexity of the electric system and notions of service. The economics of electricity are becoming more complex, requiring new tools as well as cost and pricing concepts to support the transition. Ultimately, these new methods will help define the role of the utility and the services it provides, as well as the design of rates (prices) to recover the cost of providing service. New rate structures will create incentives for customers and utilities that can guide them toward a clean energy economy.

This paper provides a short history of electric utilities and explores the current debate over the future structure and scope of the regulated distribution utility business model. The analysis presented here demonstrates that the continued existence and advancement of the regulated utility is critical to ensuring that this new transactive system delivers economic, environmental, and resilience benefits to meet current and future priorities for the U.S. electric power system. Lastly, it concludes with an overview of the path forward for transforming the role of the customer, integrating new clean technologies, and modernizing the grid through a future business model for the regulated distribution utility.

Note: While the focus here is on regulated investor-owned distribution utilities, findings and policy options may also be applicable to and adapted for public power distribution utilities and rural electric cooperatives.

Key Findings and Insights

- The electric utility business was built on the exploitation of the economies of scale inherent in its different segments. While those economies have been exhausted in generation, allowing competitive energy markets, economies are still present at the distribution level for utilities owning substations, transformers, and distribution wires. Identifying and capturing these economies will enable the development of a distribution business model that supports an increasingly de-centralized, customer-driven clean energy system that provides the lowest-cost service to customers.
- The complexity of interests and stakeholders with equities in the distribution sector is increasing; stakeholders will play a vital role in developing successful regulatory and public policy initiatives.
- The regulatory landscape for determining the future of the utility business model is changing, with growing jurisdictional ambiguity between state and federal regulators. Increased coordination by federal and state regulators will help enable the emergence of a coherent business model for distribution utilities.
- Rate design in the United States tends to be economically inefficient, in that prices do not reflect marginal costs. One effect is that rates, particularly residential rates, are largely volumetric, wherein utilities recover fixed charges through residential kilowatt-hour usage, rather than fixed charges. The consequence is that rates do not provide appropriate price signals to guide customer consumption and investment decisions.
- Ratemaking creates incentives that affect utility behavior. Once a utility's desired role is determined, it is important to create appropriate incentives to elicit that behavior. Regulation has successfully done so with energy efficiency; regulators can identify incentives to encourage distributed energy resources. There are two types of alternatives: global incentives, such as performance-based regulation, and targeted incentives.
- Electric distribution systems provide essential services to customers for which there is currently no substitute.
- Historically, utilities have been a primary source of capital that financed the development of a number of disruptive technologies, sometimes in response to policy mandates. Leveraging utility capital to support the continued transformation of the customer's role remains a legitimate policy option. Absent utility capital and rate support, other mechanisms are needed to finance clean energy technologies.
- Electric industry restructuring promoted competition. However, the pursuit of competition as an end goal is an insufficient rationale for limiting the scope of utility activity. A more legitimate goal is doing what is best for customers, which could encompass competition as a tool.

Policy Implications and Options

- **Process**:
    - Clearly articulated guiding principles provide a useful framework for developing the future distribution utility model. Guiding principles should inform the utility-planning process.
    - A robust planning process offers a forum for evaluating the path to the future utility' bringing together infrastructure requirements (whether investments will be made by utilities, third parties, or customers), cost analyses, and rate design.
    - New analytical approaches are needed to help regulators determine the appropriate scope of utility activity and the lines of business (e.g., electric vehicle charging stations) that the utilities are allowed to pursue.
- **Pricing**:
    - The nature of utility costs, both capital and operating, has changed with the introduction of new energy technologies and utility business structures. Cost-of-service studies should be re-evaluated to determine whether the proper elements of costs are defined and measured appropriately.

Executive Summary

A confluence of megatrends is driving the electric power industry to a strategic inflection point: "a time of fundamental change that will result in its doing business differently."[a] These megatrends are technological, economic, resource-based, and environmental in nature. The digital revolution and the increasing primacy of markets are already affecting American society. For the electric power industry, the technological advancements that resulted in reduced prices for both renewable energy generation and natural gas have begun to transform electricity production. New environmental regulations and advances in other technologies, such as smart meters and electric vehicles, continue the trajectory of change for the operation of electric systems. The role of the customer has also been recast, both crafted by and driving these megatrends. Customers are increasingly moving beyond their historic role of simply consuming power and have taken on additional roles such as distributed electricity generation and demand response.[b] This transformation of consumers into "prosumers"[c] is the result of the emergence of transactive energy.[d] This emergent role has the most significant impact on the distribution utility as the customers' conduit to the grid. Thus, this paper focuses on the changing nature and the future of the distribution utility.

The utility industry is in its third wave of restructuring. The first wave occurred in the 1930s with the introduction of federal regulation of wholesale interstate electricity markets and requirements to simplify the complex structures of holding companies in place at that time. The second wave began with the introduction of alternatives to utility-owned generation, leading to an increased reliance on markets and competition. This third wave involves creating a utility platform for transactive energy that will increase customer options and facilitate the reduction of greenhouse gases.

Like the earlier waves of restructuring, the current transition will create winners and losers. There is tension over whether existing utilities or competitive entities will provide new services. The utility's legal capacity to enter into new business areas and continue providing service in existing lines of business will frame the utility business model of the future. This framing is not entirely at the utilities' discretion: regulatory and legislative initiatives (both Federal and State) will largely determine what services utilities can provide versus what competitive firms will provide. Government is a facilitator of information and a guide to the transformational process. Government will both frame the scope of the future utility and determine a structure of rates to allow utilities to recover costs and provide price signals to customers. Ultimately, government must determine how well new business models capture public interest and approve the direction of the industry's path to the future.

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[a] The concept of a strategic inflection point is based upon Andrew S. Grove's, "Speech at the Academy of Management Annual Meeting," August 1998 intel.com/pressroom/archive/speeches/ag080998.htm

[b] Demand response is a mechanism where customers are paid to reduce their electricity use.

[c] The word "prosumer" was introduced by Alvin Toffler in his book, *The Third Wave* (1981) to describe the merging of the roles of consumers and producers in the information age—the third wave (agriculture was the first wave and industrialization was the second wave).

[d] "Transactive energy systems provide a means for customers of all sizes to join traditional providers in producing, buying, and selling electricity, using transparent pricing and automated controls, while ensuring a reliable and cost-efficient electricity system." gridwiseac.org/

While public attention has focused on advancing the adoption of clean energy technologies in the marketplace, the impact of these solutions on utility economics is not well understood. This knowledge gap exists because standard methods suited to understanding the economic impact of new technologies and behaviors were developed for less complex systems; however, in today's large, integrated system, the industry needs more robust methods to fully comprehend the interplay of components. A critical difference between today's utility and that of tomorrow is that power will no longer flow in only one direction, from central station power plants to consumers. In the future, power will flow from the utility to the customer and from the customer to the utility. The importance of the regulated utility as the physical and transactional interface with the grid persists with the increasing transactive role of customers. The shifting structure of utilities to a two-way system affects the system's architecture. The provision of new services is creating an increase in the information needed to operate the grid. Thus, utilities require the development of an infrastructure to support these new customer options and capabilities, and to enable the two-way flow of power and information.

The evolution of a successful utility of the future depends on sound public policy. Legislatures and regulators are responsible for critical decisions that create transformative policies, paving the way for the adoption of disruptive technologies—technologies that "transform the way we live and work, enable new business models, and provide an opening for new players to upset the established order."[1]

Two questions will help determine the robustness of a future utility business model and the impact on opportunities for new firms trying to provide electric service to customers:

1. What services can (and should) distribution utilities provide now and in the future?
2. How to design utility rates in order to provide customers with desired price signals and to compensate utilities for the services they render, including incentives to provide both traditional and nontraditional services?

Policy makers need to be cognizant of the design, responsibilities, and requirements of distribution utilities to help navigate these megatrends and guide the industry's transition. Where it is in the public interest, policy should facilitate innovation and adaptation to these megatrends, encouraging the distribution utility industry to be dynamic and flexible in order to continue its essential role as a conduit, integrating customers into the grid.

Chapter Summaries

Chapter 1 frames the issues that are driving the current debate on the future of the electric distribution utility business model. It develops two key themes in defining the future role of the utility: the services that utilities can legally provide, and how utilities charge customers for services rendered.

Chapter 2 defines an electric utility. It begins by discussing Thomas Edison's invention of the electric utility as a way of establishing a long-term relationship between providers of electric lighting service and consumers of that service. There is no single utility business model, but rather, three major forms of ownership: investor-owned, public power, and cooperatively owned. Utilities also vary by the service segments in which they operate (generation, transmission, and distribution). This chapter explains that economies of scale are critical to the development of electric utilities as natural monopolies. A natural monopoly can provide service to customers at a lower cost than multiple firms can. Different types of utilities (e.g., generation-owning, vertically integrated companies, or wires-only companies) have evolved to capture economies of scale in the various service segments. This chapter discusses how the exhaustion of economies of scale in certain segments of the industry enabled electric industry restructuring and competitive provision of service in the 1990s. Finally, the chapter describes the relationship between regulation and industry structure, developing the dichotomy between State and Federal regulatory authority.

Chapter 3 illustrates the diversity and interconnection benefits enabled by distribution utilities as conduits between customers and the grid. Utilities gain significant economies through diversity benefits that result from customers using electricity at different times, enabling a sharing of capacity that reduces overall investment needs. Transmission interconnections among utilities have and continue to provide significant value to customers. One extreme position in the current debate over the future of the distribution utility business model is the idea that traditional distribution utilities are no longer relevant and will experience a death spiral. This notion is explored and dismissed; the chapter makes the point that as long as the utility serves as the customers' conduit to the grid, distribution utilities need to exist.

Chapter 4 looks at the rationale, process, and economic impacts of regulation; in particular, the importance of regulation to the investor-owned utility business model. The regulator sets the rules that govern the utility business and determines the way that utilities recover costs (investment in capital; operating costs such as fuel and labor; and financing costs, such as debt, equity, and depreciation) through customer rates. The chapter describes multiple cost concepts, and explores the impact of using different cost concepts as the basis of rates. While regulatory practices are an arcane subject with complex details, a basic understanding of those practices is vital for appreciating how to frame the utility of the future. Finally, this chapter explains how regulatory practices influence utility business incentives and behavior.

Chapter 5 reviews the lessons learned—from historic utility responses to regulations and legislation—that have enabled the adoption of disruptive technologies. Reviewing the lessons of energy efficiency and non-utility generation clarifies the requirements for developing a framework for adopting distributed energy resources (DER). Through the lens of earlier industry experiences with disruptive technologies, the chapter evaluates net metering, a process for compensating customers for DERs by crediting their bills at a rate based on retail rates. The chapter stresses the importance of understanding the costs and benefits of DER as a basis for determining how utilities will price and compensate customers for DER; identifying an efficient path forward for DER adoption; and comparing DER to such alternatives as large-scale, grid-based renewables. This chapter emphasizes that utilities have survived and prospered after supporting disruptive technologies in the past.

Chapter 6 explains the impact of utility scope (the breadth of services) on the development of the utility business model. One historic example of scope limitations is the *Public Utility Holding Company Act of 1935*, designed to simplify the structure of holding companies. One impact was to prohibit electric utilities from owning streetcar companies. Owning electric-powered streetcars had been an integral part of capturing economies of scale early in the utility business, and the decision quickly accelerated the decline of the streetcar. A second historic example involves limits on utility ownership of generation imposed alongside utility restructuring in the 1990s. By limiting utility ownership, regulators sought to prevent incumbent utility advantage and anti-competitive behavior. However, by limiting ownership, the potential benefits to customers of utility provision (lower-cost generation based on the utilities' lower cost of capital) were lost. Furthermore, the efficacy of anti-trust enforcement has been downplayed in favor of regulatory prohibitions. Lastly, this chapter examines alternative forms of utility versus market provision of both energy efficiency and DER.

Chapter 7 provides a path forward for the utility of the future. It begins with a short review of the relationship of regulation, economic structure, and the utility business model. State legislatures, regulators, and stakeholders can all drive restructuring, and the chapter describes the role of States in more detail. This chapter discusses guiding principles that various States have adopted to pursue a broad rethinking of the future electric utility. The chapter also describes a new role for the utility: coordinating the vast increase in flow of information resulting from the emergent role of the prosumer and two-way power flows on the distribution system.

The chapter concludes that careful planning can ensure that a useful framework for evaluating both the scope and pricing of utility services will exist. The emergent field of grid architecture provides a framework for identifying relationships (costs, regulatory, physical flows, and system requirements and information) that support further analysis of structure, as well as benefits and costs. The identification and proper quantification of costs and benefits provide a basis for prudent planning and efficient pricing. In addition, analysis of the utility's financial health under different scenarios is critical to any prudent plan. Also discussed, the design of regulatory practices that support utility innovation. This chapter makes clear that the path for the future utility requires a well-reasoned dialog among stakeholders facilitated by the development and availability of analytical tools and transparent data. The chapter concludes that the future of the industry is dependent upon getting prices right, as reflected in the rates charged to customers and prices paid for DER.

1.0 Introduction

Electricity is the backbone of our Nation's economy. It is vital to modern life, including national security. It energizes light, air conditioning, and industrial processes; powers computers; and enables healthcare. Flip a switch, and there is light. Behind that switch is a vast network connecting the customer's premises first to a local distribution system, then to the transmission system that carries power from generators. This network, called the grid, has been characterized as the world's largest machine. Amazingly, most citizens in the United States get to use it, whenever she or he wants.

Historically, customers simply used electricity, and paid their utilities for the power they received and the infrastructure that delivered it. Now, an increasing number of customers are also generating electricity—injecting power into the grid and receiving compensation from their utilities. The changing role of these customers is transforming the nature of the electric distribution utility.[e] This transformation, its impact, and the challenges and opportunities it is creating are the primary focus of this paper.

There are many types of electric utilities. The object of this paper is to foster understanding of the electric distribution utility: how it is evolving and how decisions by policy makers will affect future customers. Because the path chosen will have long-term economic and social implications for our Nation, it is critical to be mindful of the potential impacts of the alternatives before us. The process of defining alternative paths is already under way. Just how the industry will further change has yet to be determined. Many economic interests seek to compete with existing utilities and capitalize on the changing role of customers. This paper is intended to guide those involved in this process to understand the current utility industry landscape and the consequences of the choices being made.

Recent headlines, such as "Solar Battle Flares Up in Arizona,"[2] report from ground zero the emerging conflict between incumbent utilities and solar providers over energy payments for customer-based solar installations. The debate is unfolding in State legislatures and public utility commissions, which both create and limit the economic opportunities for new firms and incumbent utilities through regulation and setting rates and rules for distribution utilities. At stake is the way that electric service is provided to customers in the future and how that service will be paid for. Two fundamental issues must be resolved:

1. What services can (and should) the distribution utilities provide now and in the future?
2. How to design utility rates in order to provide customers with desired price signals and to compensate utilities for the services they render, including incentives to provide both traditional and nontraditional services?

These questions are easy to ask, but the answers are complicated and can vary by region. Resolving these issues is even more difficult because of a lack of transparency, data, and independent analysis.

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[e] The term distribution utility is used broadly to identify the system that provides distribution serices, while recognizing that a system may be part of a vertically integrated utility providing generation, transmission, and distribution, or a utility that provides distribution only.

This paper focuses on the critical issues that will determine the future of the electric distribution utility business model. As the industry confronts its future, it is relevant to consider the parallels to the past and lessons learned. Thus, at times, this analysis addresses the future through the lens of history. It also identifies key policy choices that frame the future of the electric distribution utilities. Historical anecdotes and the rationale behind choices made in the past, as examples of paths previously taken, provide valuable insights for understanding and meeting today's challenges.

1.1 The Current Situation—A Strategic Inflection Point

The United States electric system is at a strategic inflection point: "a time of fundamental change that will result in its doing business differently."[3] Driving this change is the emergence of transactive energy[f, 4] and a fundamental transformation of consumers into "prosumers."[g] This means that customers can now move beyond their historic role of solely consuming power delivered by a utility and adopt an additional role as a grid resource by producing electricity, and, at times, controlling load in response to system conditions. The customer's new role as an element in system operations fundamentally changes the economic relationship underlying the current utility. Smart metering, supported by advances in power electronics, is enabling this new role. The acceleration of change is evident, and demonstrated by the rapid and growing deployment of these advanced meters. The number of smart meters in the United States increased from almost five percent of all meters in 2008 to more than 30 percent in 2013.[5]

The growing deployment of advanced meters and many other disruptive technologies—technologies that "transform the way we live and work, enable new business models, and provide an opening for new players to upset the established order"[6]—is also driving this transformation. In particular, energy efficiency, distributed energy resources (DER),[h] and energy storage, encouraged by transformational polices, are now straining the traditional electric utility business model.

Looking at the utility business model through the lens of history, during the 1880s at the birth of the electric utility concept, the question of whether customers would receive electricity from grid-based "central station generation" delivered over anetwork, or from individually owned and operated "isolated plants" arose. That question is alive again today, complicated by new alternatives, such as microgrids, that allow groups of customers to integrate with the broader grid, but that also allow them to operate in isolation.[i] This duality between a generator supplying a networked grid and distributed resources supplying all of a customer's needs poses a challenge for utilities; the response of government

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[f] 'Transactive energy systems provide a means for customers of all sizes to join traditional providers in producing, buying, and selling electricity, using transparent pricing and automated controls, while ensuring a reliable and cost-efficient electricity system." ("Updated transactive energy framework released." GridWise Architecture Council. Press release, February 25, 2015. http://www.gridwiseac.org/pdfs/2015_gwac_updated_tef_released_022515_pr.pdf.)

[g] The word prosumer was introduced by Alvin Toffler in his book *The Third Wave* (1981) to describe the merging of the role of consumers and producers in the information age.

[h] Distributed energy resources are smaller-scale and modular generating devices that provide electricity and, sometimes, thermal energy, in locations close to consumers. These technologies include solar photovoltaic arrays (PV), wind turbines, microturbines, fuel cells, energy storage devices (e.g., batteries and flywheels), and combined heat and power systems. These devices are also referred to as distributed generation.

i This approach still requires a conduit from the customer's premises to the microgrid, and the microgrid to the high-voltage grid.

regulators and the market to the various evolving options will determine where the future role of the utility will land on the continuum defined by those two disparate models.

The rapid evolution of technology and its impact on the industry has even sparked some talk of a death spiral for traditional electric utilities. In the death-spiral scenario, "the declining cost of distributed solar energy and battery systems allows many electricity service customers to disconnect from the grid, triggering a vicious cycle wherein utilities raise the rates of their remaining customers, which only impels even greater desertion."[7] Customers in this scenario transform into self-sufficient producers of their own power, leading them to abandon or bypass utility service. Underlying the death spiral rhetoric are the need for electric distribution utilities and the real valuation of utility services. In some ways, this rhetoric echoes a refrain from the fundamental discourse about industry structure at the birth of the electric industry. However, the current lack of viable alternatives to utilities and the grid suggests that the utility death spiral is an unrealistic outlook, even given the growth of DER. Rather, utilities and regulators must work together to develop a sustainable model that addresses the current challenges confronting the industry and the interests of the customers it serves.

1.2 Overview

A central premise of this paper is that lessons learned from the industry's history can illuminate the path to its future. The electric utility industry developed, at times, with intention, and at other times, by unforeseeable, ad hoc means. The industry is now in its third wave of restructuring, empowering customers to play a significant role in greenhouse gas emissions reductions. The first wave occurred in the 1930s, with increased Federal oversight of wholesale interstate markets and requirements for the simplification of the industry's holding-company structure. The second wave was the increased reliance on markets that grew out of policies promoting energy efficiency as an alternative to utility generation and pricing mechanisms that supported the development of non-utility generation. The goal of this paper is to clarify how this patchwork of many pieces, can coalesce as the industry evolves by providing informative and concrete examples in a historical context.

The starting point is to describe the multiple types of electric utilities and how they were initially designed and formed to capture economies of scale, enabling a single firm to provide service at a lower cost than multiple firms can. The paper highlights the traditional importance of customer diversity and the interconnection benefits of making service economical, a relevant point today as the new transactive role of customers continues to benefit from diversity and interconnection. The value of the utility is increasingly in its role as the conduit between the customer and the grid, enabling the capture of shared economies. In discussing the benefits utilities provide, the paper also looks more deeply at the death spiral concept in the backdrop of DER.

The paper then goes on to describe the basic tenets of regulation, with emphasis on cost as a fundamental building block in the rate design process. Regulation of utilities creates both incentives and disincentives. For example, one consequence of traditional ratemaking was a financial disincentive for pursuing energy efficiency. Regulators have since successfully worked with utilities and stakeholders to correct that disincentive by introducing mechanisms for utilities to earn profit for implementing energy efficiency programs.

With an understanding of utility history and regulation, the paper then reviews the industry's experience with both disruptive and destructive technologies. This section explores the interplay between regulation, costs, and DER in more detail. Specifically, utility experiences with energy efficiency incentives, non-utility generation enabled by the *Public Utilities Regulatory Act of 1978* (PURPA), and net metering policies provide insight into how the industry reacts to new technology.

As previously mentioned, energy efficiency is an example of a new paradigm that was incorporated into the regulatory process. PURPA led to utilities buying power from independent generators, as opposed to building power plants to supply their own customers. Regulation played a crucial role by determining the price at which utilities would buy that electricity. The transition was turbulent as the mandated price often increased costs to customers and imposed financial stress on utilities. The lesson of PURPA is that feedback, monitoring, and adjustment of transformational policies are necessary and critically important to consistently get the price right. In the case of net metering (the primary mechanism for compensating customers for DER), utilities give the customer a bill credit for generating power. The most prevalent form of DER is currently solar photovoltaics, and there is an ongoing debate over whether the price paid is right. The challenge is that without a comprehensive and transparent understanding of costs and benefits on both ends, it is difficult to pin down a valuation for DER that is fair to utilities, DER-owning customers, and non-DER-owning customers.

The paper goes on to discuss the continued growing interest in increasing the level of renewable generation and energy efficiency in the United States. The role that existing utilities, independent DER providers and customers will play is a critical and central issue. Whether traditional utilities provide these new services will depend on the restrictions that regulators place on the scope of utility activities. Regulators have restricted the scope of utility activities in the past for a variety of reasons, and some restrictions may no longer be relevant. At times, the restrictions were analytically based, but at other times, restrictions were imposed to protect competition within the industry, with tenuous benefits to customers.

The utilities of the future will share some characteristics with those of today, but replacing and updating aging infrastructure, increasing resilience, and accommodating the new transactive role of customers will require significant investment. Responsibility for making those investments must be determined and unambiguously defined. For example, transactive energy requires an entity to perform the role of data and information coordinator. New information systems will be expensive, and there is an ongoing debate about whether utilities or other independent entities should own and operate data systems.

The paper concludes with a discussion of the path forward in light of evolving technology and policies. The conclusion provides guiding principles that establish objectives for a robust, comprehensive planning process. This process will require an open and ongoing forum, and must be open to all stakeholders. Stakeholders will need access to analytical tools and a means for sharing critical data. Importantly, because many challenges to the industry are still evolving, the planning process must enable stakeholders to resolve emerging questions in a timely manner. The process must address a number of issues, including:

- Development of guiding principles that establish objectives for the planning process and serve as a starting point on the path forward

- Determining the roles of utility and non-utility providers as part of planning the provision of service to customers
- The relationship between cost of service analyses and rate design
- The costs and benefits of alternatives for achieving objectives; for example, increasing renewables to meet greenhouse gas reduction targets can be analyzed both from the standpoint of centralized versus decentralized facilities.

A final step in the planning process is a realistic assessment of the financial impact of alternative paths to the future, both on the utility and the ability of non-utility providers to provide service to customers.

The debate about the future of the electricity industry is just beginning. The overarching goals of this paper are to help equip participants engaged in the discussion with an understanding of the complex interactions that determine the future path of the distribution utility, and to lay out the steps required to move down that path.

2.0 Defining a Utility, What It Does, and Its Structure

2.1 Edison's Central Station Generation Concept

Thomas Edison transformed the world by inventing the electric utility based on the concept of central station generation. Before Edison entered the illumination market, a variety of fuel sources provided lighting, including whale oil, kerosene, manufactured gas, and to a small extent electricity. At that time, the electric industry was primarily in the business of selling lighting equipment in the form of isolated, customer-sited plants that generated electricity using the electric arc lamp by individual entities, such as mines, public parks, and large department stores. Edison modeled the first electric utility after manufactured gas lighting utilities, which transformed coal to gas in centralized facilities, transported it, and delivered it over a network. Edison followed the same concept: selling higher quality light than either manufactured gas or electric arc lamps could provide, in an ongoing relationship with customers as opposed to one-off equipment sales.[j, 8, 9,10] A modern analog is a customer's relationship with an Internet service provider versus buying a single computer.

Samuel Insull was Edison's chief financial strategist, developing elements of the electric utility business and its expansion. Power transmission lines and utility distribution poles did not exist in the country's landscape when Edison invented the electric utility. It is easy to imagine that building the electric business was very capital intensive, requiring significant investment to develop the production and distribution infrastructure. Insull based his blueprint for the investor-owned electric utility business on "central station generation" and the monopoly provision of electric service. This blueprint synthesized customer needs, financial mechanisms, ratemaking, technology, engineering, and regulation into a utility business model that thrived for the better part of a century. Insull also championed the notion that electric service was a natural monopoly due to economies of scale; it is most economical for a single entity to provide all service in a geographical area. Ultimately, the utility model involved a societal grant of monopoly status in exchange for customers sharing the benefit of lower costs and the provision of universal service in what is known as the "regulatory compact."

2.2 Defining Utilities

Electric utilities have historically been considered natural monopolies due to the presence of economies of scale. Utilities "supply, directly or indirectly, continuous or repeated services through more or less permanent physical connections between the plant of the supplier and the premises of the consumer."[11]

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[j] After seeing the much celebrated electric arc lamp at the Paris Opera House, Robert Louis Stevenson observed:

> "A new sort of urban star now shines out nightly, horrible, unearthly obnoxious to the human eye; a lamp for a nightmare! Such a light as this should shine forth only on murders and public crime, or, the corridors of lunatic asylums, a horror to heighten horror."

Edison characterized gas lighting as a "nasty yellow light" with the "nauseous dim flicker of gas, often subdued and debilitated by grim and unfriendly globes." Edgar Allan Poe shared Edison's disdain for gas: "Gas is totally inadmissible within doors. Its harsh, unsteady light offends. No one having both brains and eyes will use it."[NEEDS A REFERENCE]

In a formal sense, a natural monopoly exists when the "entire demand within a relevant market can be satisfied at lowest cost by one firm rather than by two or more."[12]

The traditional structure of an electric utility, depicted in Figure 2.1, is a vertically integrated monopoly providing a one-way flow of power generated at power plants, transported over long distances by transmission lines, and distributed to all customers within the utility service territory. The electric distribution utility owns and maintains the wires that physically connect to the customer and provide a conduit to the grid. The grid is a coordinated network of multiple generators and transmission lines owned by multiple entities to provide energy to consumers.

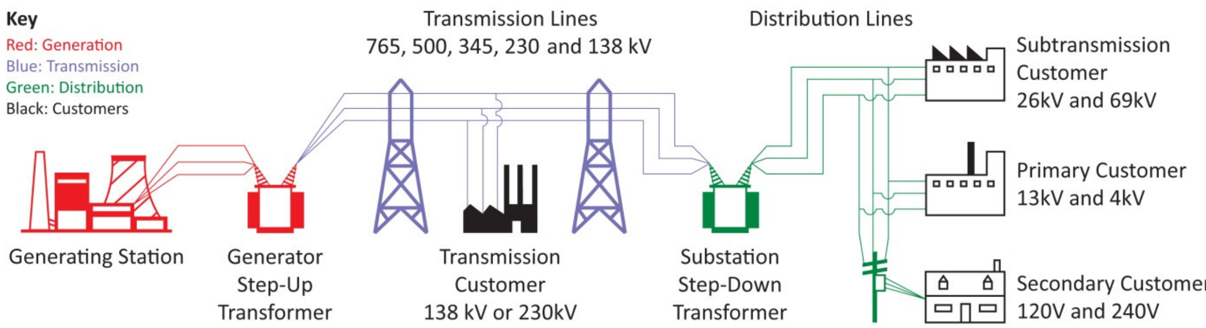

Figure 2.1. The Historic Electric Utility Industry Structure

Source: NERC, "Understanding the Grid," August 2013. Reproduced with permission.

2.3 Ownership Taxonomy

Early in the industry, utilities developed with vertically integrated structures, providing service from generation through distribution to customers. Initially, there were two forms of ownership: investor-owned (owned by private entities) and public power (owned by governmental entities, such as municipalities). President Roosevelt's New Deal in 1935[k] created a third class of ownership: rural member-owned electric cooperatives (co-ops). Co-ops are owned by the customers they serve, with management answering to a community-elected board. In contrast, investor-owned utilities (IOUs) are owned by investors, and management answers to those investors. Many co-ops receive power from Federal power project generation, often over federally owned transmission facilities. The creation of Federal power projects and co-ops initiated the process of disintegration of vertical ownership structure of the traditional utility by introducing generation and transmission that was (and still is) provided by federally owned facilities, creating a separation between power generation and delivery.

The electric utility system in the United States is a mix of different entities distinguished by ownership and scope (generation, transmission, and distribution). Table 2.1 demonstrates the diversity of the utility types that currently work together to provide service to customers.

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[k] On May 11, 1935, Roosevelt signed *Executive Order No. 7037* establishing the Rural Electrification Administration (REA). It was not until a year later that the *Rural Electrification Act* was passed and initiated the lending program that became REA. Most rural electrification is the product of locally owned, rural electric cooperatives that got their start by borrowing funds from REA to build lines and provide service on a not-for-profit basis. (http://www.nreca.coop/about-electric-cooperatives/history-of-electric-co-ops/ Accessed May 21, 2015).

Table 2.1. Taxonomy (Ownership/Scope) of Utility Business Models with Representative Firms

	State-Regulated IOUs	Cooperatively Owned	Publicly Owned	Federally Owned	Independent Power Producers
Vertically Integrated	Oklahoma Gas & Electric	None	Los Angeles Department of Water & Power	None	None
Transmission and Distribution (wires only)	Pepco	Southern Maryland Electric Cooperative	Clallam County Public Utility District	None	None
Generation and Transmission	None	Basin Electric G & T	New York Power Authority	Tennessee Valley Authority	LS Power
Generation and Distribution	DTE Energy; Consumers Energy	Fox Island Electric	Lansing Board of Water & Light	None	NRG
Transmission	None	Upper Missouri Power Cooperative	Transmission Agency of Northern California	Western Area, Bonneville, and Southwestern Power Administrations	ITC; Hudson Transmission; Transource Energy; Clean Lines Energy Partners
Distribution	Mt. Carmel Public Utility Co.	Kenergy	Nashville Electric Service	None	None
Generation	None	None	Wyoming Municipal Power Agency	Bureau of Reclamation	Calpine; BP Energy; Tenaska

Table 2.1 illustrates the matrix of ownership patterns types and the three functions of the utility—generation, transmission, and distribution. Some utilities perform only one function, while others perform multiple functions. In States that have restructured the electric utility sector by dismantling vertically integrated utilities, independent firms (rather than utilities) perform some functions.

Table 2.2 provides some basic statistics underlying the taxonomy of different classes of utilities. There are far fewer IOUs than public power companies or co-ops, but IOUs are the dominant service provider in the country, with the greatest proportion of customers. In a number of restructured States, distribution IOU customers may choose to buy electricity from competitive, non-utility service providers. The proportion of non-utility generation (40 percent) also reflects the effect of industry restructuring, in which customers and utilities increasingly rely on power purchases from the market as opposed to generation owned by vertically integrated utilities.

Table 2.2. Comparative Statistics of Different Types of Utilities[13]

	Number of Providers	Number of Customers				Generation in Megawatts (MW)	
		Total Customers	Full Service	Delivery Only[l]	Percent of Total	MW	Percent
Public Power	2,009	21,202,459	21,194,051	8,408	14.4%	402,023	9.8%
Cooperatives	192	18,735,096	18,721,416	13,680	12.8%	205,170	5.0%
IOUs	871	100,488,785	90,660,272	9,828,513	68.5%	1,548,463	37.7%
Federally Owned	9	39,032	39,030	2	0%	283,110	6.9%
Power Marketers	211	6,268,219	6,268,219	0	4.3%		
Non-Utility Generators						1,686,869	40.6%
TOTAL	3,292	146,733,591	136,882,988	9,850,603	100%	4,107,635	100%

This taxonomy focuses on different combinations of the components that comprise the traditional vertical structure of utilities. It is important to recognize that there are many other entities involved in the provision of power, such as independent system operators (discussed in the next chapter) who coordinate system transactions. Increasingly, there are competitive non-utility entities (e.g., solar providers) providing energy services at customers' premises, which are not reflected in the current taxonomy. The regulatory process of implementing new utility models will also have an important impact on the business models and roles of many of these other entities.

Available economies of scale largely determine the structure of utilities, and there is a great deal of geographic variability across the nation. In many urban areas, utilities initially captured economies by building large thermal units and distributing power in close proximity to those plants. Long-distance transmission enabled capturing the benefits of increasingly larger generators and provided the financial impetus for utility consolidation. Long-distance transmission moved power to local monopoly distribution utilities, enabling the capture of economies of scale from a single-distributor provider.

The development of mega-scale hydroelectric facilities in the Pacific Northwest enabled the capture of economies of scale associated with harvesting the electric potential of the Columbia River. In this case, there was a separation of generation ownership (Federal) from distribution (public). Federal development of electricity generation demonstrated that the capture of economies of scale did not necessarily depend on distribution by the same entity that provided transmission and generation.

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[l] Delivery-only customers are those that purchase energy from an alternative supplier.

Rural coops developed a joint action concept to pursue economies of demand, such as the Arkansas Electric Cooperative Corp. formed in 1949 by a group of Arkansas distribution cooperatives to develop generation and transmission.[14] In the 1960's smaller municipal utilities, formed joint action agencies to also either build power plants or purchase wholesale power to serve their member municipal utilities who then in turn distributed electricity to their citizen-customers.[15]

Since its inception, the taxonomy of the electric industry has evolved. This evolution was driven both by economics, such as the consolidation of utilities, and policies, such as industry restructuring. The premise of industry restructuring was the notion that economic regulation was a proxy for market forces, and that actual competition could more efficiently achieve the same outcomes. In the restructuring process, many utilities separated the various functions (e.g., generation) and opened up service provision to the market. Consequently, the nature of the vertically integrated utility is very different today from 30 years ago.

In summary, there are a number of ownership structures for providing service to different segments of the industry (e.g., generation versus transmission)—each structure with different levels and types of oversight. This diversity leads to very different rate processes, rate structures, and incentives. The following chapters discuss how the financial and regulatory structure of IOUs provides incentives for such issues as pursuing energy conservation. The analysis primarily focuses on IOUs that provide distribution service either as vertically integrated utilities, transmission and distribution utilities, or as distribution-only utilities. There are two reasons for the focus on IOUs. The first is that the relationship between IOUs and State regulators plays a large role in determining which business lines utilities are restricted from pursuing. The second is that IOUs deliver approximately three-quarters of the power in the United States. Many of the lessons learned in the discussion of IOUs are directly relevant to co-ops and public power utilities.

2.4 Interplay of Economies of Scale and Utility Taxonomy

Various aspects of electric utility service have historically displayed attributes of natural monopoly, including economies of scale in generation, transmission, and distribution; the economies of coordinating and integrating the operations of dispersed generation facilities; and complementarities between generation and transmission. Samuel Insull, the early thought leader in the creation of the electric utility industry, based his utility business model on economies of scale - "(s)triking economies in the production, distribution, and sale of electricity have permitted a general and widespread reduction in selling price."[16] Over time, some aspects of economies of scale have been exhausted (e.g., generation), while some remain (e.g., the interconnection of customers in a particular area) and others have been transformed (e.g., system coordination). The continued existence or exhaustion of economies of scale largely determines whether a particular segment of the industry is amenable to competitive restructuring.

In the generation segment, understanding that economies of scale were the foundation of the traditional utility model is key to understanding how the segment has evolved, as some of those economies have been exhausted. "The cost of building a new plant on a per-unit basis decreased until the late 1960s, despite increases in the cost of almost all materials and labor. Exploitation of larger (more thermodynamically efficient) units that demonstrated scale economies was responsible for the drop."[17] The exhaustion of these economies was largely the result of the tremendous complexity of building ever-larger power plants. Thus, the exhaustion of scale economies in generation, combined with new, efficient, smaller-scale generators were factors that ultimately led to the start of restructuring in the 1980s and fueled interest in competition in the 1990s.

The vertically integrated structure of the electric industry also led to economies of coordination through the economic dispatch of generating units to meet instantaneous customer load requirements. Historically, there have been substantial cost savings from vertical integration for all but the smallest utilities, with the greatest integration cost savings going to the largest, fully integrated utilities.[m]

In the transmission segment, the physics of the system and cost of building transmission lines provide economies of scale. From an engineering standpoint, the capacity of a transmission line increases with the square of the line's voltage, whereas the cost of building a line increases linearly as a function of voltage. Consequently, a 200-kilovolt line will cost twice that of a 100-kilovolt line, but will carry four times as much power.[18] The existing transmission network and reliability restrictions on operating various lines affect the ability to exploit the inherent economies of scale. Furthermore, as a component of a network (the grid), there is no longer a compelling reason for transmission to be owned by a vertically integrated utility.

In contrast to the exhaustion of economies of scale in generation, the continuing economies of scale in distribution support the notion of a single service provider in a particular area. The reason is that:

> …as the number of customers on the network or the total power demand on the network increases, given a particular geographic area served by the distribution system, unit distribution costs can be expected to decline. These apparently pervasive economies of density imply that it would be inefficient to serve the same geographic area with more than one distribution system.[19]

There is some debate about whether economies of scale in distribution will persist with increasingly lower-cost DER and storage. In discussing a world with cost-effective DER, Steven Corneli, Senior Vice President of Policy and Strategy at NRG, argues that the natural monopoly characteristics of the distribution utility would be:

> …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.[20]

While some customers might exit the system with cost-effective DER, customers without DER will continue to use the distribution company as a conduit to the grid. In thinking about the natural monopoly nature of the distribution utility, it is important to specify the product that it provides. The

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[m] It must be noted that studies of vertical integration referred to were based upon data prior to industry restructuring and the strengthening of the wholesale market function in Independent System Operators (ISOs)/Regional Transmission Operators (RTOs) which coordinate wholesale transactions and the operation of the bulk electric system. These savings have largely migrated from the individual utilities to power systems (the ISOs and RTOs).

narrow view taken in this paper is that whether distribution natural monopoly status persists will depend on whether a single firm can provide the conduit to the grid in a particular geographic area at a lower cost than multiple firms. Time and technological change will ultimately determine whether this remains the case.

2.5 Federal/State Jurisdiction and the Regulation of Utilities

The regulation of utilities began as a local and State function. The industry became more interstate in nature as it grew and evolved, and it became necessary to empower the Federal Government to also regulate the industry. The line between Federal and State jurisdiction was much clearer when the industry was organized as vertical monopolies. Increasingly, the line between Federal and State jurisdiction has blurred, creating jurisdictional ambiguity.[21]

In his 1898 presidential address to the National Electric Light Association (the predecessor of the Edison Electric Institute, the industry trade group for IOUs), Samuel Insull called for utility regulation. He believed that the regulated monopoly could provide a stable financial environment to support the development and expansion of electric utilities. Insull had witnessed the destructive competition at the dawn of the electric era, with duplicative distribution systems and an inability to harness scale economies, warned in his address that, "acute competition necessarily frightens the investor, and compels corporations to pay a very high price for capital."[22]

Insull promoted a grant of exclusive franchises[n] in exchange for regulated rates and profits.

> While it is not supposed to be popular to speak of exclusive franchises, it should be recognized that the best service at the lowest 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 conditions of public control, requiring all charges for services fixed by public bodies to be based on cost plus a reasonable profit.[23]

The economic regulation of utilities was promulgated in response to a convergence of utility and customer interests. Utilities recognized that regulation protected their monopoly status and provided a stable financial environment that supported their development and expansion. Customers saw that regulation prevented a pattern of excessive charges and rate discrimination. In 1905, Charles Evans Hughes—at that time, a distinguished New York City attorney—was appointed counsel to investigate the organization and operation of New York City's gas and electric companies. He found that utilities were overcharging the public, committing rate discrimination, and providing unsafe and unreliable service. In order to "prevent a recurrence of the mischiefs revealed in this investigation," Hughes recommended the creation of an independent regulatory agency with power to investigate the quality of service provided by the utilities and the reasonableness of their rates.[24] As a result of this investigation, Hughes became known throughout the State and defeated William Randolph Hearst to become Governor in

[n] Utility franchises allow access to streets, which is necessary for the distribution of power. The manufactured gas industry stalled Edison's development of the Pearl Street Station by thwarting, for a time, his ability to receive a franchise. J.P. Morgan would not proceed without the grant of a franchise.

1906. In 1907, Governor Hughes succeeded in obtaining passage of legislation that created the Public Service Commission of the State of New York. Now, all 50 States have public utility commissions (PUCs) with primary regulatory responsibility for rates and consequently the determination of the future of the investor-owned distribution utility business model.

The New York Public Service Law is fairly typical in the broad regulatory powers granted to PUCs and in its specification of the utility's obligations. The New York Public Service Commission is the agency responsible for implementing the New York Public Service Law. Section 65 of the law states that every electric corporation "shall furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable." State PUCs have direct responsibility for evaluating the investments, rates, and performance of electric utilities and for determining a just and reasonable rate for the provision of service.

The jurisdiction of PUCs covers the setting of retail rates and provides the commissions with audit powers over any of the components of the utility's revenue requirement. These include such key components as fuel costs, transactions, and sale-for-resale revenue. As part of a utility's obligation, it must demonstrate to the satisfaction of the commission that it is providing safe and adequate service at a just and reasonable rate. This provides the State PUCs with the ability to evaluate investments in utility plant and plan to maintain resource adequacy (the availability of sufficient electrical infrastructure to meet the needs of customers).

However, regulatory gaps have arisen with the introduction of State PUCs. The U.S. Supreme Court created what became known as the Attleboro Gap when it found a price increase on an interstate electricity sale by the Rhode Island PUC to be unconstitutional. In 1917, Narragansett Electric Lighting Company of Rhode Island entered into a 20-year contract to sell power at a contracted rate to the Attleboro Steam & Electric Company in Massachusetts to be delivered over a line from Rhode Island to Massachusetts, where it was to be metered. In 1924, the Narragansett Company, having failed to cover its losses associated with providing power to Attleboro, received approval from the Rhode Island PUC for a new increased price. The Attleboro Company appealed the Rhode Island PUC’s decision and, ultimately, won. The U.S. Supreme Court found that:

> The test of the validity of a State regulation is not the character of the general business of the company, but whether the particular business which is regulated is essentially local or national in character; and if the regulation places a direct burden upon its interstate business it is none the less beyond the power of the State because this may be the smaller part of its general business.

Consequently, State PUCs were unable to regulate interstate transactions. The lack of a Federal regulatory body left a regulatory void: the Attleboro Gap. The importance of this void grew with the development of trusts that owned multi-state utilities and with increasing interstate power transactions. By 1935, more than 20 percent of the electricity generated in the United States moved across state lines[25] and was, therefore, not subject to regulation.

To close the Attleboro Gap, Congress passed the *Federal Power Act of 1935*, empowering the Federal Power Commission (FPC), predecessor to the Federal Energy Regulatory Commission (FERC) to “provide effective Federal regulation of the expanding business of transmitting and selling electric power in interstate commerce."[26] The FPC's new jurisdiction included regulating sale of electricity at wholesale, defined by the act as "a sale of electric energy to any person for resale."[27] Generation, local distribution, and wholly intrastate sales and transmission were exempted from Federal regulation, and Federal regulation was to extend "only to those matters which are not subject to regulation by the States."[28]

The bounds of Federal and State jurisdiction have been subject to question and court clarification over time. In 1964, the U.S. Supreme Court established a "bright line" between State and Federal jurisdiction in the Colton Case (FPC v. Southern California Edison Co.), which involved a sale of power generated in California (at the Hoover Dam) between two California utilities (sold by Southern California Edison to the City of Colton's municipal utility). The California PUC and Southern California Edison argued that the State should have jurisdiction over the sale. However, the Court found that the transaction was not subject to regulation by the State, and further found that:

> Congress meant to draw a bright line easily ascertained, between State and Federal jurisdiction … by making FPC jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.[29]

Experience has shown us that the bright line has shifted with the evolution of policy and industry structure. During the California energy crisis, the president of the California PUC, with the Chairman of the Electricity Oversight Board, reported to the Governor that:

> A momentous consequence of California's attempt to create a market in electricity is that the Federal Government now regulates California's electric system. … By handing the reins of California's electric system to Federal regulators, the State of California no longer possesses the ability to protect California businesses and consumers.[30]

Currently, about two-thirds of electric power delivered in the United States is transferred through organized wholesale markets regulated by FERC in a respective region. This has resulted in a federalization of regulatory protection to customers and the financial structure of investments for suppliers. As technology changes the options for operating power systems, including increasing the role of the customer, the line between State and Federal regulation will become more ambiguous. Jurisdictional ambiguity is the uncertainty created by the blurred line between Federal and State jurisdiction. The nature of this regulatory ambiguity and the role it might play in molding the future of the distribution utility business model is discussed further in later sections of this paper.

3.0 The Benefits that Utilities Enable

As the customers' conduit to the grid, distribution utilities enable the capture of diversity and interconnection benefits. This role will grow in importance with the increasing transactive role between customers and the grid.

3.1 Benefits of Diversity of Demand

Diversity of demand occurs when different customers consume electricity at different times; it is a critical factor contributing to the economy of electric utility industry operation. Samuel Insull, at the turn of the twentieth century, believed that "[t]he fundamental basis of profitmaking in public-service business is the diversity of demands."[31] To understand the benefits of diversity, Insull performed load research on all sorts of customers, ranging from customers in an apartment block to electrified streetcars.

Insull saw how to increase economies by capturing the diversity of demand,[32] smoothing the variable electric load, and, thus, driving down the per-unit capital cost of the equipment necessary to provide service. For example, he found that apartment blocks had a diversity factor of 3.2, implying that it would take more than three times the generation capacity to serve the load with generators owned by individual customers.[33] Diversity not only existed within a particular customer type, but also between customer types. Electric traction and streetcars were a source of daytime demand, pursued by the early electric companies to complement demand from nighttime lighting service. As new customer activities continued to expand, the diversity of those activities provided benefits from the shared use of utility capital and the ability to provide service at lower costs.

Diversity benefits enabled the capture of economies of scale. As articulated by Insull:

> By utilizing the diversity factor of these varied requirements, that is, the difference in the time of the day, and in the many cases the difference in the month of the year, when many consumers use our product, electric energy can be supplied from one central system more economically than in any other way. Great savings can be affected by utilizing large generating units, unifying methods of transmission and distribution, economizing in spare or reserve generating plant, economizing in labor and by the possession of financial resources, enabling the central station company to employ high-class experts to study economies of production and selling.[34]

Today, the diversity of loads continues to play an important role in enhancing the economies of providing electric service.

3.2 The Value of Interconnection

Interconnection is the process of electrically integrating independent electric systems with transmission lines. The First World War (WWI) provided the early impetus for the development of utility interconnections. Prior to the war, utilities "endeavored to bring large areas under single or associated distributing systems, achieving unified corporate control over large market areas. Companies feared dependence on neighboring systems for power and doubted whether they would receive a fair share of the economies of large-scale generation."[35] As *Electrical World* observed: "The incentive for interconnecting electric service systems has been absent, where each individual company has been able to meet its local requirements and at the same time maintain a sound financial condition."[36]

During WWI, priority for using available turbo generators was for ships and ammunition plants, rather than for meeting growing power needs. Faced with the prospect of severe electric-capacity shortages, Bernard Baruch, Chairman of the War Industries Board, ordered a survey of electric generation facilities in the United States. The survey revealed "the possibility of using existing power facilities more effectively by interconnecting power stations and utilities that had complementary load and diversity factors."[37] Utilities responded and interconnected with each other, increasing capacity and efficiency.[o]

WWI awakened interest in interconnected systems, spawning two major studies of hypothetical interconnected power systems, called Superpower and Giant Power. Superpower was designed to provide power generation and distribution in the region from Boston to Washington (and extending 130 miles inland). Superpower, which would be owned by a holding company, would operate as a power pool, with new Superpower plants generating power for delivery and distribution by individual utilities to their customers. The Giant Power proposal called for the development of large mine-mouth coal-fired power plants to transmit power over high voltage lines to distribution companies in the State of Pennsylvania.[38] Both proposals failed, largely because of opposition from utilities, that saw their power to control investments and operation shifting away from them and toward these new entities, losing the ability to make new investments in generation. However, the post-WWI interest in interconnections led to the geographic growth of power systems in two ways: (1) the development of power-pooling agreements to coordinate inter-utility transactions, and (2) the expansion of holding companies garnering the value of interconnection.

The Conowingo hydroelectric project led to the first multi-utility interconnection in the United States in 1927. Philadelphia Electric, Public Service Electric and Gas Company of New Jersey, and the Pennsylvania Power and Light Company formed the Pennsylvania-New Jersey Interconnection (PNJ) in 1927 to coordinate and share generation from the Conowingo hydroelectric project on the Susquehanna River and to provide a diversity of generation sources for those periods when water flow was inadequate to provide sufficient power. PNJ was the predecessor of the Pennsylvania-Jersey-Maryland Power Pool, and, subsequently, as a regional transmission operator (RTO) called the Pennsylvania-Jersey-Maryland Interconnection. PNJ was an early example of how different corporate entities could benefit from power trades, transacting with each other according to each company's supply and demand characteristics.

Holding companies increasingly developed as vehicles for pursuing economies of scale.

> Holding companies were used to build up large systems under single control to obtain the economies of large-scale operation and management, and also the profits from building large systems and subsequently servicing them... Thus, where contiguous

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[o] Despite assistance provided by interconnection, power supply proved inadequate, necessitating rationing by October 1918. "Only the sudden end of WWI prevented (the revelation of) a serious shortage of power supply with which to meet the increased demands for equipment of an army of five million men."

> operating companies could not be merged or local operations could not be conducted through departments and district offices, because of legal obstacles, the holding company proved to be an efficient device for achieving the economies of large-scale operation by bringing operating companies under common control.[39]

However, the increasing size of interconnections had unanticipated consequences when they failed. The Great Northeast Blackout of November 9, 1965, in which 30 million people through the Northeast and Canada were left without electricity, demonstrated the consequence of system failure. A key finding of the Federal Power Commission study on the causes of the blackout was that utilities, individually and collectively, lacked the situational awareness to effectively respond to system failure.[40] The need for increased coordination led to the formation of the New England and New York Power Pools (predecessors of Independent System Operator of New England and New York Independent System Operator).[p]

The power pools coordinated system reliability through operations based upon inter-utility transactions. Benefits materialized through energy savings from the coordination of generation and sharing of the reserves required to maintain reliability in the event of a failure of system components. For example, due to seasonal diversity of load in New York State (air conditioning driving downstate load in the summer and heating driving upstate load in the winter), it was possible for individual utilities to maintain an installed reserve margin of 18 percent individually and yield a 22 percent system-wide reserve margin. Consequently, individual utilities were able to reduce the amount of generating capacity that they maintained, lowering the capital investment needed for generation investment, reducing costs to consumers.[41]

Another interconnection benefit is illustrated by the formation of the New York and New England Power Pools in the 1960s, which further formalized the shifting of reliability and economic coordination from vertically integrated utilities to a centrally coordinated power system in many regions of the United States.[q] This consolidation of economic dispatch at a system level was a major step in the transformation of the traditional vertically integrated utility model, and thus began the process of transferring control and planning of generation from the utility to multi-utility power systems. The existence of power pools enabled the development of independent system operators (ISOs) and RTOs[r] that further centralized the coordination of generation through markets. ISOs and RTOs also formed in other parts of the country. Today, ISOs and RTOs manage approximately 60 percent of the U.S. electric supply, providing interconnection benefits to both utilities and customers.[42]

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p The North American Electric Reliability Council (NERC) and regional reliability councils were also formed to help coordinate reliability around the country.

q After the Great Northeast Blackout of 1965, New York Governor Nelson Rockefeller engaged Dr. Edward Teller, the father of the hydrogen bomb, to develop a plan to avoid blackouts. His solution was a centralized computer that removed the generator owners from control of dispatch. The formation of the New York Power Pool provided an alternative that left a good deal of discretion with the utilities.

r Independent System Operators (ISOs) are organizations that coordinate the operation of power systems, allowing diverse resources to participate in system operation in a non-discriminatory manner. Regional Transmission Organizations (RTOs) are responsible for moving power via transmission over large regional areas. The function of coordinating transactions is integral to operating the grid; ergo, RTOs are frequently also ISOs. This paper uses the term ISO inclusively, to imply both transmission coordination and grid operation.

3.3 The Continuing Importance of Utilities

3.3.1 The Prospect of Electric Utility Obsolescence: The Death Spiral in the Context of Distributed Energy Resources

New technologies, enabled by advances in power electronics, are radically changing the options for providing service. This technological transformation raises a threshold question of whether distribution utilities and the grid will continue to be needed or become a historic relic. The dialog about the utility death spiral compares electric distribution companies to streetcars and landline telephone services—two utility services largely overtaken by competitive alternatives. As we shall see, these are not valid analogies for the situation facing electric distribution companies.

In May 2014, Barclays Bank downgraded the entire electric utility industry, believing that competitive challenges from solar power producers presented a real and present danger. The foundation of that threat is the combined impact of solar power and energy storage, such as the pairing of Tesla's home batteries with rooftop solar.[43] Barclays contended that the current ratings and bond prices did not reflect the long-term challenges of solar power to the electric utilities.

> In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar and storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.[44]

What is the nature of this reconfiguration, this re-imagining of the role of the utility? In this outcome, the distribution utility role is supplanted by a cost-competitive substitute. There would no longer be a need for the distribution company, and the grid would be displaced by customers providing their own power from their own generators—essentially returning to the isolated plant business model of the early 1880s. However, if regulators recognize the need for the distribution company and the value of the grid, they understand that the financial health of utilities is important to sustain. The utility industry is keenly aware of the disruptive threat of the so-called death spiral, but it would be an extreme outcome on the spectrum of possible models of customer service based on an alternative to the grid. In a report prepared for the Edison Electric Institute, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," Peter Kind observes:

> While the immediate threat from solar [photovoltaics (PV)] is location dependent, if the cost curve of PV continues to bend and electricity rates continue to increase, it will open up the opportunity for PV to viably expand into more regions of the country…as the installed cost of PV declines from $5/watt to $3.5/watt (a 30 percent decline), the targeted addressable market increases by 500 percent, including 18 States and 20 million homes, and customer demand for PV increases by 14 times. If PV system costs decline even further, the market opportunity grows exponentially. In addition, other distributed energy resources (DER) technologies being developed may also pose additional viable alternatives to the centralized utility model.[45]

3.3.2 Reports of the Death Spiral Are Premature

In order for bypass of the electric distribution utility to be a real threat, alternative provision must, at a minimum, demonstrate a reasonable expectation of cost parity. Analysis projecting cost parity suggests that obsolescence is not an imminent threat to the utility industry. Estimates of expected cost parity differ. As noted above, Barclays predicted cost parity occurring in four States by as early as 2018. Figure 3.1 is from a study prepared by the Rocky Mountain Institute that provides a comparison of off-grid solar power plus battery systems with utility price projects.[46] This study projects that Hawaiian Electric Industries will be to be the first utility in the country for which customers will have an incentive to bypass the utility.[s] The forecast parity price for the next utility is not reached until 2025 (for Consolidated Edison Company's Westchester commercial customers). Importantly, parity is not reached for residential customers in this service territory until 2049.

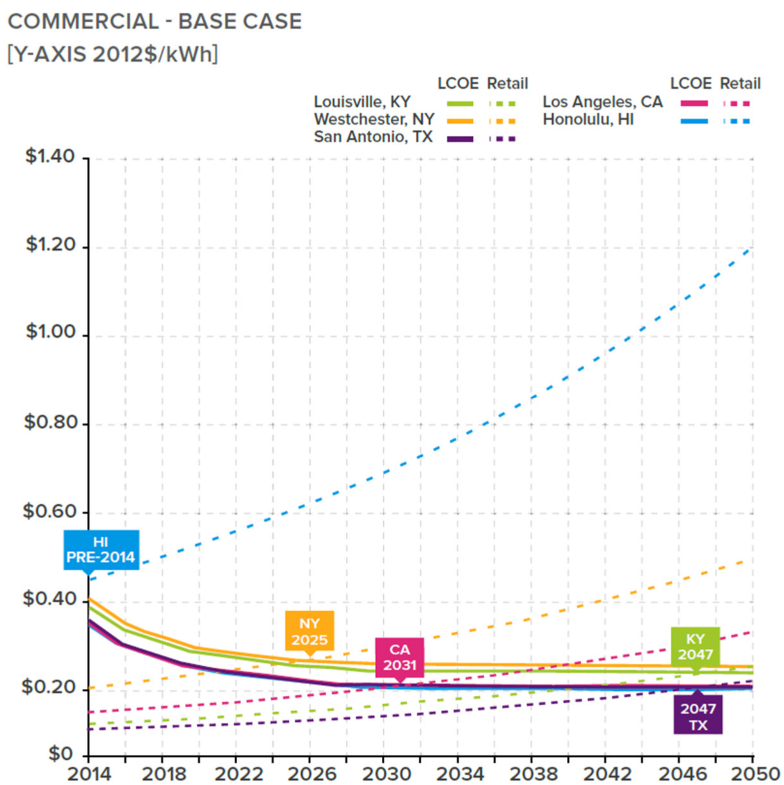

Figure 3.1 Off-Grid vs. Utility Price Projections

Source: Rocky Mountain Institute. 2014. "The Economics of Grid Defection." February 24. Reproduced with permission.

Solar power combined with energy storage is only one potential bypass technology. Ultimately, it is conceivable that electricity customers who also have gas service will be able to install gas-fired electric

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[s] Hawaiian Electric Industries is often considered the harbinger of the future when it comes to utility bypass. Although the proliferation of DER in Hawaii is significant (largely due to the high energy costs of an economy that imports all of its non-renewable energy), storage has not been widely adopted and customers are still relying on the grid for various services. The current issues are less about bypass and more about the ability of the system to absorb all of the excess DER generation.

generation that also provides heat and hot water, which could allow them to bypass the distribution system.[t] Alternatively, these customers could have the ability to sell power back to the grid and become a grid resource,[47] benefiting from the increased diversity benefits that they bring to the network.

It should be clear that a dichotomy of service perspectives emerges with bypass, with some customers going it alone as opposed to being part of a system. In a system based on individuals providing their own power, customers would be responsible for the resilience of their own power supply during the next Hurricane Katrina or Sandy. This model would represent a radical shift from the current paradigm of universal service, in that those who could afford the redundancy would have supply, while those who could not would be without power.

Price, reflected by cost parity, is an important determinant of the success of customer bypass. Feasibility is also important. Not all customers can (or want) to install, operate, and maintain DER. A host building requires space and access to potential energy (either solar or delivered fuel) to develop DER. For example, it is difficult to develop solar potential for homes located in heavily treed settings (where a homeowner may be in the shadow of trees that belong to neighbors). Similarly, large skyscrapers do not have the roof area to install sufficient PV modules; nor, in many cases, do they want to devote the space to the requisite electricity- generating facilities. To complicate matters, if a commercial entity installs generation equipment and chooses to unplug from the grid, it is not only responsible, but also liable for the provision of electricity.

Even with access to potential energy sources, there are four additional issues associated with defecting from the grid,[48] each adding to the cost of self-sufficiency:

1. The need for and cost of sizing solar capacity for the least-sunny periods
2. System voltage able to handle maximum continuous power demand and demand surges (e.g., air conditioning)
3. The need for back-up generation
4. Battery capacity sized for multiple days of consumption.

Furthermore, there is the issue of customers' ability to finance. To develop a generation system at a customer's premises, that customer must be able to afford to install the equipment, or enter into a purchase power agreement with a third party to do so. Many non-creditworthy electricity customers would be unable to finance or contract isolated plant equipment or would lack the means to maintain and operate it. An electric system based on isolated plants means abandoning well-accepted principles of universal service.

On a cost basis, it appears that the cost parity required to support isolated plant development is not imminent. In addition, a number of factors beyond simple parity further hamper a widespread shift to the isolated plant model. These factors include the loss of diversity benefits provided by the grid and the loss of reliability enabled by the distribution utility acting as the conduit between the customer and the

[t] However, such technologies as the Beacon 10 engine, based on the Sterling engine, are still under development and are not yet cost effective.

grid, providing both back-up and energy storage. Even zero-net-energy homes benefit from interactions with the grid. A zero-net-energy home produces as much energy as it consumes. The benefit it receives from the grid includes the classic diversity benefits of capacity sharing and using the grid as a storage battery to help balance its generation and demand.[u]

Utilities may face financial difficulties associated with lost sales and payment for power at retail prices, but it seems for now that the report of their demise is premature. For now, and for the foreseeable future, the public needs and will continue to need electric utilities that act as conduits to the grid. This does not mean that electric utilities are the only relevant provider of customer service, only that it is inappropriate to dismiss them as irrelevant, as is implied by the death spiral rhetoric.

That said, utilities are confronting real financial difficulties. Demand growth in the United States has declined due to a combination of successful energy-efficiency efforts, customer-side DER, and a sluggish economy. Significant expenditures will be needed to improve the resilience of the grid in the face of increased frequency and intensity of storms and the rise in sea levels. In addition, the evolution of a transactive role for customers highlights limitations of the current rates and revenue structures of traditional utilities. As will be discussed in more depth later in this paper, the fundamental problem is that while the utility industry is transforming, cost analysis and rate design is not keeping up with industry change.

Regulation plays a determinative role in utilities' financial health. Regulation largely determines customers' access to options, and the rate treatment and relative cost of those options. Regulation also determines which services the distribution utility may provide to customers, or whether those services are to be provided by independent entities. Allowing utilities to compete provides an added source of margin and contributes to sustaining the financial health of the utility. In determining the terms that will allow utilities to thrive as integral providers of service, it is also necessary to recognize that the rules established for utilities will largely determine the playing field for non-utility providers, which also have a good deal to offer customers.

3.3.3 Lessons from Obsolescence in Other Industries

The discussion of the death spiral should reflect the history of utility obsolescence—it has happened before, and some relevant lessons can be learned from those experiences. The legal precedent of denying the Market Street Railroad the rates to recover the cost of providing service in the face of obsolescence sheds light on the risk that utilities face from the development of destructive technologies. When competitive substitutes for utility service exist, the utility regulator may not have the ability to provide rates to stave off bankruptcy, and the utility may not survive. Market Street Railroad was experiencing an operating deficit resulting from declining ridership and the inability to raise prices. Municipal streetcars, buses, and automobiles provided a competitive alternative to the service provided by the railroad. Market Street Railroad's costs became stranded and unrecoverable from customers. The expected obsolescence of the streetcar infrastructure undermined its ability to argue for a higher rate of

[u] Information is not readily available to the public on use of the grid by net energy homes. It would be interesting for utilities to collect and report grid usage by net energy homes. This can be done, by evaluating time of day consumption and production data of homes designated as net energy.

return to attract capital investment. The U.S. Supreme Court found that regulation is not obligated to insure value or to restore value lost due to the operation of economic forces.[49]

The recent experience in the telephone industry is also viewed as a cautionary tale for electric distribution.

> Dramatic technological change has evolved over the past 35 years, which has led to the development of a new infrastructure system; new services that are providing abundant transfer of information; and the convergence of voice, data, and entertainment into one combined service from what had previously been viewed as separate and distinct services and industries. Today, the number of customers who utilize the previously exclusive copper wire telephone system represents a rapidly declining percentage of the market for telephone services. In addition, the advent of cable-based phone service has sped the decline in copper-based services.[50]

One distinguishing feature between electric and telecommunications utilities providing "plain old telephone service" is the feasibility of parallel networks with telecommunications, such as cellular, that allow all customers the opportunity to bypass copper wires. In contrast, the fundamental role of the electric distribution utility is to serve as the conduit between the customer and the grid.

If customers are to be self-sufficient, they must provide all necessary services currently provided by the grid. Options to support universal bypass are neither cost competitive nor feasible; neither are they likely to be available any time in the near future. Utilities will remain an important provider of customer services for the foreseeable future.

4.0 Economic Regulation of Utilities

Utility business models and regulatory restructuring are two sides of the same coin. For investor-owned utilities, the public utility commissions (PUCs) will have to approve any changes to either rates or the scope of utility activities—the two key parameters in determining the future of the utility business model. Co-op and public power entities' boards will similarly have to approve changes. The result would be tremendous diversity and uncertainty in both future rate design and business models.

Rates are the schedule of prices that utilities charge for the provision of service. Price formation is fundamentally different in a regulated process from that of a market. Market prices are determined through the balance of supply and demand, and profits are the residual of market price and cost. In contrast, ratemaking (the process of establishing rates) is an administrative process designed to recover expected costs and provide the utility an opportunity to earn an allowed rate of return. The structure of electric rates determines the nature of price signals to consumers. Additionally, the recovery of costs in ratemaking introduces certain behavioral incentives to utilities, as discussed later in this chapter.

The "regulatory compact" allows utilities to earn a fair rate of return and to recover the cost of depreciation, operating expenses, and taxes in exchange for providing safe and adequate service at just and reasonable rates. Ratemaking as an instrument for implementing the compact is largely based on U.S. Supreme Court precedents that frame the legal requirements of regulation.[v]

Ratemaking is a two-step process: (1) the determination of the utility revenue requirement and (2) the design of rates.

The revenue requirement is a forecast of the budget that the utility will require to meet expected customer' electricity needs during a future test year. The "rule of ratemaking" provides the formula for determining the utility revenue requirement:

Revenue Requirement = rate of return **x** *depreciated rate base* **+** *depreciation*
+ *O&M (including fuel)* **+** *taxes*

The rate-design process balances price structures with a utility's ability to recover its revenue requirement. The process requires allocating the elements of utility costs to different customer classes (e.g., residential, commercial, industrial, etc.) and to different rate categories (e.g., energy charges). A key step in the rate-design process is the determination of cost causation. Cost causation is important, because it helps develop rates whereby different customers pay the cost of providing the service they use. Various elements of costs (e.g., distribution costs, metering, transmission, etc.) are thus allocated to

[v] For example, in Knoxville v. Knoxville Water Company, 212 U.S. 1 (1909), the U.S. Supreme Court recognized the right of a utility to recover the initial cost of infrastructure investment through depreciation charges. In Bluefield Water Works & Improvement Company v. Public Service Commission, 62 U.S. 679 (1923), the U.S. Supreme Court established the principle that "the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate … to maintain and support credit …"

each customer class. Ideally, each customer would pay only the cost of providing services it uses. As discussed, this is an aspirational goal that utilities often do not achieve in practice.

Typically, the rate-design process begins with a cost study that characterizes the elements of the utility's cost of providing service to customers, and determines cost causation (the underlying rationale for incurring that cost). Elements of cost fall into three basic categories:

1. **Fixed costs** are the basic costs of providing service that do not vary with the level of energy consumption. An example of a fixed cost is the cost of a meter, a necessary element for providing service that is functional whether the customer uses very little or a great deal of energy.
2. **Capacity costs** measure the impact of usage on the system's infrastructure where increases in customer usage can trigger the need for additional investment. For example, increases in air conditioning usage can increase the need for distribution investment, where the size of a substation supporting a residential distribution lateral power line is driven by the need to serve reliably the peak (highest) usage, typically driven by air conditioning on the hottest day of the year. Capacity (demand) charges can be designed to signal customers' expected contribution to new investment and provide a mechanism for recovering those costs, once incurred.
3. **Variable costs** are primarily the energy costs associated with providing service. These costs change based on the level of load and the types of generation capacity available in the system.

In an ideal ratemaking scheme, the elements of cost would fit naturally into the three components of rates: (1) fixed (customer), (2) capacity (demand), and (3) energy (variable) charges. The customer charge would reflect the fixed costs of providing a service. The energy charge would represent the cost of energy, determined either through an energy market or by the fuel to power the utility's own cost of generation. Capacity costs vary by demand and are driven by the maximum system usage, because electrical systems are designed to meet peak energy consumption. The demand charge is a mechanism for both recovering capacity costs and providing a price signal to customers about their contribution to costs at the peak. Typically, the demand charge is set annually, serving as a ratchet on the customer's bills.[w]

4.1 The Right Costs for Rate Design—A Balancing Act

Ratemaking is more art than science, and is largely the art of compromise. It is a balancing of three primary objectives articulated by James C. Bonbright, an eminent academic observer of utility regulation, as:

1. The financial-need objective: allowing utilities a fair return

[w] A ratchet is a circumstance in which the rate will not decline until an appropriate period elapses (often, 1year). Thus, a demand charge based on a demand of 3 kilowatts set in month one (say, January) might increase if a higher demand, 5 kilowatts, for example, is set in month two (February); but lower demand in subsequent months will not reduce the demand charge until the period has expired.

2. The fair-cost-apportionment objective: distributing revenue requirements fairly among the beneficiaries of the service
3. The optimum-use objective: designing rates to discourage wasteful use while promoting all use that is economically justified in view of the relationships between the costs incurred and the benefits received.[51]

Among these three objectives, there is tension between the concepts of just price (objective 2) and economic efficiency (objective 3). The concept of just price originated with Saint Thomas Aquinas' views on the immorality of raising prices in times of shortage, and was incorporated in early price regulation in England.[52] Economic efficiency is concerned with creating an optimal allocation of resources as a way of maximizing social welfare. Economic efficiency does not reflect views of just prices or equity. It is the role of regulation as the principal to sort out and weigh the importance of each principle when establishing rates.

Complicating the balancing of competing objectives in rate design is the use of different cost perspectives. This landscape can be divided into two categories: (1) embedded versus marginal costs, and (2) private versus social costs.

Embedded costs (also called accounting or average costs) are costs incurred by the utility that reflect historic investment decisions, providing a retrospective perspective on rates. On the other hand, a marginal cost study provides a forward looking perspective by estimating the cost of providing the next increment of service. Consider, for example, a customer seeking to expand a server farm, thus increasing its electrical requirements: the marginal capacity cost for that customer is equal to the incremental cost of adding facilities to support the server farm's new, additional consumption. Alternatively, the embedded costs are based on the average cost of investments to provide service to all other customers that the utility has already made. Marginal costs more closely reflect market prices, which in competitive markets are equal to the marginal cost of providing the last increment of supply. Consequently, rates based on marginal costs provide more economically efficient price signals to customers. On the other hand, the use of marginal costs also complicates the rate-design process, because the costs underlying the development of rates do not neatly line up with the costs incurred. It then becomes more difficult to design rates that recover the utility's revenue requirement.

Cost perspective also has a significant effect on the rate design. Utility regulation relies on the concept of a just price, which has been viewed by both regulation and the courts as the private costs that utilities incur to provide service. The issue is whether social costs (externalities— costs that do not have a market value) should be reflected in utility rates.

Saint Thomas Aquinas considered a just price as one where the producer added only as much to the price as was sufficient for its support. The history of utility pricing largely followed this medieval framework, codified by U.S. Supreme Court decisions, into what became cost of service regulation, whereby utilities were able to recover the cost of providing service and a return on capital consistent with the opportunity cost of money.

Cost-of-service regulation is a process of administratively determining just prices based on the private costs of utilities. In cost-of-service regulation, environmental costs have been internalized in prices only through the recovery of increased capital and operating costs associated with meeting standards, such as sulfur-reduction requirements designed to mitigate the impact of acid rain. Under this paradigm, unregulated environmental effects associated the provision of electric service are not reflected in utility rates.

The economics profession has long understood the concept of market failure due to social costs not being incorporated in prices. For example, in 1890, Alfred Marshal developed the concept of externalities, and Arthur Pigou provided a solution of taxing externalities to create efficient market outcomes in 1920.[53,54] Some would argue that because greenhouse gas emissions endanger public health and welfare, regulated prices that do not reflect or in some way mitigate those externalities are not just.[55]

It should be evident at this point in the discussion that rate design is a tug of war among different interests to shift costs between customer classes and from fixed charges to create specific pricing incentives. Shifting cost responsibility between classes raises some customers' rates and lowers the rates for others. Shifting from fixed to variable costs benefits those who want to encourage customers to conserve energy. As the Rocky Mountain Institute concluded: "If increasing portions of customer bills are collected in the form of fixed monthly charges—and less in the form of volumetric charges or other types of charges that the customer has the ability to influence—the incentive to conserve could be diminished."[56] The following graphic, based upon an Electric Power Research Institute study oftypical residential customer electric bills, demonstrates the difference between actual fixed and variable utility cost responsibility and the actual design of residential rates.

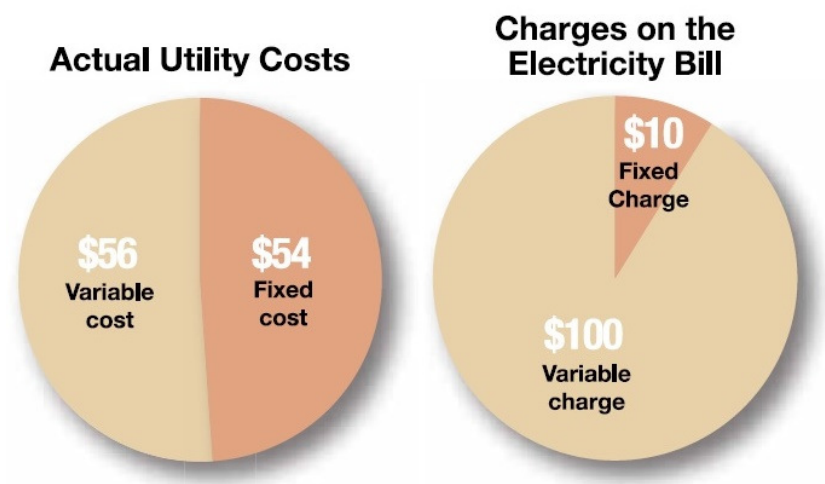

Figure 4.1 Actual Utility Fixed Costs versus Fixed Charges on the Electricity Bill

Source: Zummo, Paul. "Rate Design for Distributed Generation: Net Metering Alternatives." American Public Power Association. 2015. 2. Reproduced with Permission.

Rate design is particularly important for the sustainability of the distribution company of the future. As will be discussed later, many states have implemented net metering programs that compensate customers for distributed energy resource (DER) generation at retail rates that may not accurately value DER. When rates do not reflect costs, there are issues surrounding whether the "right" amount of DER capacity is being added and whether the utility's ability to recover its revenues is inhibited.[57]

4.2 Incentive Impacts of Regulation

Utility ratemaking creates unique incentives that differ from those experienced by firms in competitive markets that are concerned with minimizing the total cost of production. Regulation is a substitute for competitive market pressures; it creates a variety of incentives, driven by the unique treatment of different cost elements, both in the determination of rates and during the period between rate cases.

As explained in the previous section, the rate process determines how much a utility can earn, based on the two primary factors: (1) the allowed return on capital, and (2) the utility rate base. Utilities earn profit from a return on capital. If a utility's cost of capital, including equity, is below its allowed return, it has an incentive to over-invest in capital. A reverse bias is created if the cost of capital is set too low or regulation creates obstacles to fully recovering capital; for example, promoting energy efficiency without fixed-cost recovery.

Utility investment is not subject to a market test; rather, it is subject to a regulatory test that applies the "prudence standard" as the principal method of determining whether costs are recoverable in rates. The prudence standard requires that costs of capital investments are reasonable, given the information that was known and knowable at the time the costs were incurred. In a regulated environment, utilities first make investments. Then, PUCs evaluate the decisions pertaining to those investments when the utility seeks to include them in rates for cost recovery. Between 1981 and 1991, PUCs disallowed $19 billion of "imprudently" incurred capital investment related to power plant construction (primarily nuclear) from ratepayer cost recovery.[58] Consequently, from the regulated utility's vantage point, an important issue continues to be whether an investment is recoverable in rates, not whether the investment proves to be cost effective for ratepayers. Ideally, the design of the distribution business model of the future will align cost recovery for the utility with what is cost effective for customers.

The rate treatment of non-capital items, such as fuel and labor costs, also creates unique incentives for operating decisions. For some expenses, such as labor costs, absent an extraordinary event—for example, a major storm—the amount that the utility will recover is predetermined. Other expenses, say, fuel costs, are flow-through items in rates, with adjustment mechanisms that true-up actual costs. For these items, the utility has little incentive (absent explicit incentive mechanisms) to take actions that will increase efficiency. For example, a utility that flows through fuel costs would be indifferent to whether it weighed a unit train of coal at the mine mouth or the power plant. In the mid-1980s, during the review of incentives associated with fuel pass-through mechanisms, it became evident that one New York utility that weighed coal trains at the power plant was paying for the weight of rainwater that collected in the coal cars, and was recovering the cost of doing so. A competitive firm would have incentive to weigh the train at the mine.

PUCs have tried designing incentive mechanisms to make fuel and purchase power practices more efficient. For example, in the 1980s the New York State Public Service Commission, partially in response to utilities weighing coal trains at power plants, developed a mechanism that allowed a sharing of 20 percent of energy savings off the fuel budget incorporated in the revenue requirement, and a 20 percent penalty for expenditures above the target.[59] The result was a significant increase in management attention to reducing cost of fuel and purchased power expenses.

Public utility commissions have also sought to create a business environment closer to that of a market economy. Performance-based ratemaking (PBR) is an approach that provides a mechanism to establish a multi-year revenue requirement. Like traditional ratemaking, PBR requires a determination of the revenue requirement, following the rule of ratemaking, as the starting point in the rate process. However, once determined, the revenue requirement changes over time due to inflation and estimates of a firm's ability to improve efficiency. Typically, revenue requirements can be re-opened if unanticipated events that dramatically affect projected energy use or costs occur.

The advantage of PBR is that it allows the utility's executives to focus on the task of running the company efficiently, as opposed to focusing on increasing revenues through performance in rate case proceedings. The utility's ability to keep revenues below the forecasted level creates an incentive to be efficient. One challenge in setting the initial rates relative to productivity is that the most productive utilities start from a high level of expectation about keeping costs down, making it harder to get ahead and benefit, while productivity laggards find it much easier to make out well by beating targets. Over time, that forecast level declines due to an efficiency factor that affects the change in allowed rates. Performance-based ratemaking mechanisms initially require much more work from both State utility regulators and applicants because the rules are new and there is little confidence in the parameters (fear of bias). A disadvantage of PBR is that one way to save on costs is to reduce the quality of service, such as postponing such activities as tree trimming. To offset this disadvantage, regulators can impose quality-of-service metrics to counteract the financial incentive to reduce service quality, substituting increased regulatory oversight for service quality to focus on costs and rates.

The structure of new business models will create incentives that guide utility operation and investment decisions in the future. In the process of developing this new regime, it is important to provide incentives for utilities to both pursue and enable non-utility service providers to meet national goals of a clean-energy economy.

5.0 Disruptive Technologies and Innovation Supported by Regulatory Mechanisms

5.1 Development of Disruptive Technologies

The history of the electric industry is all about disruptive technologies. Electrification itself is a disruptive technology. Manufactured gas lighting was a casualty of the incandescent bulb. In fact, the publication of Professor Edison's discovery of the distribution of electric light caused a rapid and significant decline in the value of manufactured gas securities.[60]

The utility industry has a long history of innovation that has improved the way it does business and provides service. Many of these changes were incremental, including increases in generation efficiency and size, transmission capacity and distance, and early adoption of computer methods for operations and planning. Utilities have also played an integral role in fostering disruptive technologies that have driven change in the industry, sometimes for the betterment of consumers and, at other times, to their detriment—and not always by choice. It is often a consequence of transformative public policies designed to encourage increased energy efficiency and alternatives to utility generation by leveraging either the utility's creditworthiness or intellectual capital to facilitate change.

Policy and economic pressure on utilities to support the development of disruptive technologies began with the peaking of economies of scale in generation in the early 1970s. The real cost of generation declined until approximately 1970, when economies of scale reversed, becoming dis-economies of scale.[61] The 1970s were tumultuous for the electric utility industry, fostering policies that promoted the introduction of and rate support for disruptive technologies. Delays in nuclear power plant construction (largely complicated by post-Three Mile Island safety requirements) drove financing requirements, accelerating costs beyond even the highest estimates of nuclear critics. Other factors driving cost and uncertainty, including oil embargoes, coal strikes, and natural gas shortages, stimulated public questioning of utility generation expansion plans. As a result, many corners of society and branches of government yearned for alternatives to large-scale utility construction, leading to transformative policies that supported the introduction of disruptive technologies, particularly energy efficiency and non-utility generation.

Two significant disruptive technologies emerged from the 1970s: (1) demand-side management (DSM)[x,62] and (2) non-utility generation.[y] The development of non-utility generation was enabled by technological breakthroughs that allowed the construction of small, efficient power plants and inspired regulatory practices that created markets for selling the output of those generators. Demand-side

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[x] Demand-side management encompasses systematic utility and/or government activities to change the amount or timing of customer's use of electricity. This may involve investments or incentives that increase energy efficiency or pricing programs that reduce demand during peak periods or periods of system shortage. As defined by the Electric Power Research Institute, DSM includes energy efficiency and load management, and has six load shape objectives: energy efficiency (reduction in overall energy use), peak clipping, load shifting, valley filling, electrification, and flexible load shape.

[y] As used here, non-utility generation is not utility owned, and costs are not part of the utility rate base. Non-utility generation includes Qualifying Facilities—generation facilities eligible to receive avoided cost-based rates.

management involved a series of mechanisms designed to increase the efficiency of customers' energy use. Transformative policies made the success of these disruptive technologies possible.

Disruptive technologies, when coupled with transformational policies, provide an ongoing basis for innovation and contribute to the industry's current inflection point. Transformational policies, often initiated by Federal legislation and implemented by States to enable innovation, require the development of new pricing and valuation regimes. For non-utility generation, as described further in this chapter, State public utility commissions (PUCs) were charged by the *Public Utilities Regulatory Policies Act of 1978* (PURPA) with establishing the price that utilities would pay for the output of non-utility generators. For energy efficiency, transformational policies required State PUCs to create a regime for determining the desired level of energy efficiency that utilities should pursue, and to determine how utilities would be compensated for doing so. Together, the disruptive policies associated with DSM and non-utility generation have laid the groundwork for fundamentally transforming consumers into a prosumers. This new role of the consumer has enabled power systems to operate more efficiently and utilities to avoid investment in distribution infrastructure.

The distribution utility is experiencing a dramatic challenge from the disruptive technologies and enabling transformational policies discussed in this chapter, such as net metering. These disruptive technologies are evolving as competitive alternatives to regulated utility service. State regulators will ultimately determine the nature of this mix and, therefore, the financial health of industry-owned utilities, the role of non-utility service providers, and the cost of electricity for customers.

5.2 Energy Efficiency

5.2.1 Development of Energy Efficiency

The transformation of consumers to prosumers began in the mid-1970s, as the focus of regulatory policy began shifting from building load-supplying generation to decreasing demand through cost-effective options. Initial efforts in energy conservation focused on the provision of information via advertising, bill inserts, and energy audits of customers' premises. *The National Energy Conservation Policy Act of 1978*[63] (part of the *National Energy Act*) authorized the U.S. Department of Energy to create mandatory energy standards for certain products and to oversee the development of State energy conservation plans for large electric and gas utilities. These energy conservation plans would address, among other things, utility compliance in offering energy audits to residential customers.[64]

During this time, there was also growing interest in developing energy efficiency as an alternative to building nuclear power plants. The White House Council on Environmental Quality required an evaluation of energy efficiency in the development of Environmental Impact Statements used in the siting process.[65] States also became increasingly interested in developing energy-efficiency (EE) programs, while utilities, unfortunately, had a disincentive to pursue cost-effective investments in EE. In 1989, John Rowe, an industry thought leader and then-Chief Executive Officer of the New England Electric System, drove home the point that utilities would pursue energy conservation if it became profitable when he famously pronounced, "the rat must smell the cheese."[66] The Energy Conservation Committee of the National Association of Regulatory Utility Commissioners took Rowe's admonition to heart when it passed a resolution that "a utility's least-cost plan should also be its most profitable plan."[67] Thereafter, PUCs began exploring, with utilities and stakeholders, regulatory incentives that enabled utilities to profit from EE.

Over the next two decades, a variety of incentives and rate mechanisms were developed to do just that. They ranged from incentive mechanisms adopted by PUC programs that allowed utility shareholders to share the net benefits of savings from DSM-induced increases in energy efficiency (compared to avoided supply costs), to rate decoupling mechanisms that reduced the utilities' risk of revenue shortfalls. Consequently, some utilities have become active participants in demand-side management, fostering demand for such efficient technologies as compact fluorescent lights, and facilitating a technological transformation in end-use efficiency.

Thus, utility-administered EE programs enhanced the growth of transformative and disruptive technologies that led to the development of significant EE potential and a changed role for the consumer. These programs offered rate-funded capital (such as financial incentives to customers for installing high-efficiency equipment, product rebates and direct investment) in response to State regulatory and legislative initiatives. This is one of many examples of the utility sector funding, at regulatory direction, the very destructive technologies that altered the nature of the service provided.

The continued need for reductions in energy consumption as part of a strategy for reducing carbon emissions is clear, although utilities' exact role in doing so is still a matter of debate. A fundamental issue in the current re-evaluation of the utility business model is the utilities' role in promoting EE and supporting distributed energy resources (DER). Given the continued dependence of utility revenue and fixed cost recovery on sales volume, there is a natural disincentive for utilities to cut usage. John Rowe demonstrated that incentives work—the role of incentives should be part of any discussion of the future business model.

5.2.2 Implementing Utility Energy Efficiency

Five issues must be addressed in order to effectively implement an EE program. The first three are regulatory mechanisms required to develop a positive business case for energy efficiency: (1) program cost recovery, (2) lost margin recovery, and (3) performance incentives. The fourth and fifth issues relate to determining the desired level of energy efficiency and are mechanisms for evaluating the effectiveness of energy efficiency programs.

Program Cost Recovery

Energy efficiency programs may require substantial upfront investment costs (e.g., staffing requirements, program development costs, marketing materials, and back-office systems) as well as ongoing program costs. Costs can be recovered either as an expense or capitalized. As an expense, costs are passed on to customers without the opportunity for utilities to earn a return on capital, as they do when costs are capitalized.

Compensation for Lost Revenues Leading to Lower Margins

Again, the utility's ability to recover costs and earn margin (profit) is determined by the rate-setting process. Currently, most utilities recover the bulk of their fixed costs (including the utility's authorized profit margin) through variable energy charges or as volumetric rates: the amount paid is a function of the volume consumed. If actual sales are lower than estimated, the utility will receive less revenue than expected, experience a revenue shortfall, and not earn its authorized return on capital. Two approaches implemented by PUCs for returning a utility's margin and removing this disincentive for energy efficiency are: (1) lost revenue adjustment mechanisms and (2) decoupling. In a lost-revenue-adjustment mechanism, the level of revenues lost from sales reductions are directly attributable to a particular energy-efficiency program and are recovered through a rate rider. Decoupling is a mechanism that separates revenue recovery from the amount of energy sales. There are two major forms of decoupling—one in which total revenue is capped, the other caps revenue *per customer*. A benefit of decoupling is that it does not require an accurate estimate of EE program costs or benefits, and functions as a self-adjusting revenue mechanism.

Incentives for Pursuing Energy Efficiency

Performance incentive mechanisms are designed to align financial incentives with the delivery of cost-effective EE and DER investments. As such, all performance incentives are a form of targeted performance-based regulation. There are two basic approaches:

1. A **bonus mechanism** pays the utility some fraction of program-administration costs for achieving a pre-defined performance target (e.g., percentage reduction in annual retail sales). The utility is rewarded for exceeding a savings target (given a fixed program budget) or for achieving high market penetration for an efficiency program.
2. A **shared-savings mechanism** provides the utility a share of the net benefits that customers receive from participating in the portfolio of EE programs. This mechanism works to align customer and utility shareholder interests.

Incorporating Energy-Efficiency Programs into Utility Resource Planning

A new planning paradigm, integrated resource planning was introduced in the late 1980s to recognize demand-side resources (EE and DSM) as legitimate alternatives to building generation in order to maintain resource adequacy.[z] In this new planning paradigm, several supply-side and demand-side alternatives are evaluated using a variety of cost-effectiveness tests[aa] to determine a least-cost mix for serving customers. Integrated resource planning (IRP) has not only been used to evaluate the least-cost option, but has also become a vehicle for evaluating alternative policy mechanisms (e.g., incentives) to develop those options. As described below, IRP can provide the foundation for a valuable process to help define the path to the distribution utility of the future.

Measurement and Verification

Measurement and verification are critical for determining the effectiveness of EE programs. Energy savings are the absence of energy use. To the extent that utilities (or third party providers of EE services) receive compensation or incentives based on energy savings, measurement and verification provide the basis for those payments. Measurement and verification are performed by utilities under regulatory

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[z] Resource adequacy: Sufficient resources to adequately provide reliable service to customers.
[aa] Several cost-effectiveness tests, each employing a different cost perspective, have been adopted for evaluating DSM. For example, the total–resource-cost test measures costs and benefits from a societal perspective, including externalities; whereas the ratepayer-impact test estimates costs and benefits as they affect ratepayers through rates.

oversight to determine benefits from utility energy service programs, and it is used by individual customers that have contracted for delivery of EE services. Estimates of energy savings are generally "determined by comparing the measured electricity consumption and demand after the implementation with what it was before the implementation."[68]

By resolving these five issues, regulators in conjunction with the electric utility industry have implemented customer-financed energy efficiency programs that in 2014 had exceeded more than $ 6 billion a year with more than an additional $ 1 billion a year for demand response programs.[69]

5.3 The Resurgence of Non-Utility Generation

5.3.1 PURPA as a Transformative Policy

PURPA provided the regulatory impetus for non-utility generation by requiring utilities to purchase power from non-utility generators,[bb] or qualifying facilities, at the utility's avoided cost (the cost determined by PUCs that the utility would have incurred "but for" the purchase of that power). Generation based on PURPA rates demonstrated that it was possible to coordinate and supply utility load requirements with non-utility generation. The PURPA experience also demonstrates the importance of getting the price right, particularly when entering 20+ year contracts to purchase power.

The breakthrough in generation technology that effectively neutralized economies of scale for generation and enabled non-utility generation was combined-cycle generation, which captured and used waste heat from generation. The success of non-utility generation was largely the result of this new generation technology in conjunction with regulatory requirements that utilities purchase power from non-utility generators.

Combined-cycle plants increased power plant efficiency from approximately 40 percent to more than 60 percent.[70] These new power plants tended to be small and standardized, and used natural gas, allowing for rapid siting and construction, which greatly reduced financing and development costs.

Long-term, fixed-price contracts played an important role in the ability to finance non-utility generation. By entering into long-term contracts with creditworthy utilities, non-utility generators were financeable. "New rules resulting from PURPA allowed entities with little or no balance sheet to obtain long-term (up to 30 years) power purchase agreements with creditworthy utilities."[71]

Although the Federal Energy Regulatory Commission (FERC) established the broad parameters of the avoided-cost pricing regime for implementing PURPA, States were responsible for implementing avoided-cost rates. Two important lessons emerged from the experience: the importance of getting the price right and the need for prudent regulatory oversight using feedback on policy adoption to adjust further implementation.

States adopted different definitions of "avoided cost," which translated into different methods of estimation. In Maine, State regulators used the estimated cost of completing the Seabrook Station

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[bb] The generic terms non-utility generation and independent power producers are used interchangeably for generation not owned by utilities. Qualifying facilities are independent power producers that are eligible for special treatment under PURPA.

nuclear power plant, already recognized as a financial disaster, as the proxy for avoided costs used in 30-year contracts. In reaction, one of the executive vice presidents of Central Maine Power observed, "(t)hey took the stupidest thing we ever did and required us to repeat it."[72] In 1982, the avoided-cost price was set at 9 to 10 cents per kilowatt-hour (kWh),[73] when the operating cost of the most expensive oil-fired power-providing units displaced by non-utility generators was 3 to 4 cents per kWh.

New York and California adopted analytical approaches of estimating long-run streams of avoided costs (based on forecasts of the value of energy and the capacity value of the generation) that were used as the basis for long-term contracts to purchase power from qualifying facilities. Both States' utilities were required to purchase power without regard to how much power was needed. Once established, it took a regulatory fiat to reset price schedules—effectively ignoring the economic principle of supply and demand—so that when supply exceeded expectations, prices did not change. This experience revealed a problem: if a technology (e.g., gas turbines) is economical at a given price, then many projects will be economical; if there is no market feedback mechanism to reduce the price and slow supply as the incremental value of new units goes down, utilities and consumers alike will overpay and overbuy. California's qualifying facility acquisition process created a new Gold Rush. By 1987, more than 15,000 MW of new capacity signed contracts, with more than 3,000 MW coming online and operating.[74]

The effect of the unfortunate regulatory policies that ignored the interplay between supply and demand was to increase the financial commitment that utilities made on behalf of customers, while driving down the value of all generation. The impact of inelastic (non-price-responsive) avoided-cost methods was extreme for the Niagara Mohawk Power Company (NMPC), an upstate New York utility. By 1993, NMPC's non-utility generator purchases were approximately 28 percent of its power supply, but 67 percent of costs.[75] The utility's anticipated installed capacity reserve margin[cc] was forecast to grow to 40 or 50 percent by late 1990s (as compared to the 18 percent requirement at the time). The company ultimately lost a great deal of money (much of which was recovered from ratepayers) when it restructured the contracts by paying independent power producers $3.6 billion in cash, 20.5 million shares of common stock, and the proceeds from the sale of an additional 22.4 million shares of stock.[76]

To stop the unintended financial bleeding created by the implementation of PURPA's power purchase mandate, PUCs shifted to a competitive bidding system.[dd] Under this regime, independent power providers would compete to have their capacity and energy purchased by IOUs in long-term contracts, in quantities dictated by planning studies. The questions of what is needed and at what cost have returned to the resource-acquisition process.[ee] Competitive bidding was short-lived, giving way to more expansive regulatory and legislative visions of competition and restructuring.

[cc] The installed-capacity reserve margin is the amount of generation capacity in excess of that required to meet peak (maximum) load requirements to enable the power system to operate reliably in the event of a generation or transmission failure.

[dd] Competitive bidding was a multi-faceted process for determining which non-utility generators would receive long-term purchase-power contracts. Attributes included price, fuel certainty, environmental characteristics of the unit, and whether the unit was dispatchable.

[ee] Resource acquisition is the process of procuring sufficient energy and capacity to meet expected customer energy requirements.

Feedback and analysis of the effects of avoided-cost policy in the late 1980s and early 1990s were both slow and incomplete. Critical issues that form the basis of prudent utility management and regulatory policies, such as financial impacts and their effect on the utility's resource requirements, were not addressed by the responsible PUCs and, as with the NMPC example, the customers and shareholders paid the consequences.

5.4 Distributed Energy Resources

5.4.1 Distributed Energy Resources as a Disruptive Technology

If deployed on a larger scale under current policies, DER could pose a threat to the current utility business model. As discussed, DER—including fossil and renewable energy technologies (e.g., photovoltaic arrays; wind, combustion, steam, and micro-turbines; reciprocating engines; and fuel cells,), energy-storage devices (e.g., batteries and flywheels), and combined heat and power systems—comprises a range of smaller-scale and modular devices designed to provide electricity (and sometimes, thermal energy) in locations close to consumers.[77]

5.4.2 Net Metering as a Transformative Policy

Net metering is a rate process used to compensate customers for the production of electricity from DER (largely from on-site solar electricity). The issues surrounding net metering are, in many ways, analogous to the problems associated with the implementation of PURPA, with the utility providing the financial backbone for developing the disruptive technology.

Net metering provides customers a bill credit for DER generation. In this situation, a customer both provides power to the utility and buys power from the utility. The bill credit is based on retail electricity rates (as opposed to wholesale market prices). Even when a customer's total consumption and production match, it is unlikely that customers' production will coincide exactly with their consumption. Therefore, it is likely a customer will sometimes be selling excess and at other times buying power from the utility. A customer's energy bill credit can be banked for a limited time; in effect, storing sunlight both between times of day and seasons. Largely as the result of the *Energy Policy Act of 2005* requirement for states to investigate net metering, 43 States and the District of Columbia have adopted a form of net metering.[78] Net-energy metering has led to the substantial development of rooftop solar power generation and created market large enough to drive down the price of photovoltaic panels.

A number of State public utility commissions are now investigating two important rate issues associated with net metering for both consumers and utilities: net metering (1) does not provide a price signal for efficient investment decisions to develop the appropriate amount of solar power, and (2) may increase cross-subsidies between customers with and without solar photovoltaics.

Price is the most important mechanism for conveying information to customers and suppliers.[79] Customers use prices, reflected in their retail rates, as a basis for consumption decisions and, increasingly to determine whether to invest in DER. Net metering increases both the importance of establishing retail rates that adequately account for the costs and benefits of consumer decisions, and of implications for driving investment needs and operating procedures on the grid.

If prices are not cost-based, some customers may subsidize others, potentially exacerbating rate adequacy issues. Whether net metering pays an appropriate price for solar power or not, net metering introduces a structural rate issue. That is, "(b)ecause residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DER customer will avoid paying some or all of its fair share of the fixed costs of grid services."[80] As Joskow and Wolfram observe: "Almost all residential and small commercial consumers in the U.S. buy electricity on rate structures that do not vary with changes in overall supply and demand conditions, marginal costs, or wholesale market prices from either an ex ante or real time perspective."[81] Therefore, with net metering, the utility will (without new compensatory rate mechanisms) under-recover its rate contribution to capital costs unless it collects the lost revenues, at least in part, from non-participating ratepayers, in the form of higher rates.

There is considerable debate within the electric industry about whether there is a net energy metering (NEM) subsidy. This subsidy has generally been defined by the revenue shift resulting from the difference between the customer's bill savings due to the onsite energy production and the utility's costs avoided by not having to deliver the electricity displaced by the energy produced on-site.[82] The fact that DER will contribute to an under-collection of utility revenues without shifting those revenue responsibilities seems to be a foregone conclusion, given the volumetric approach to rates. Revenue shifting from net metering is only part of the picture. Another issue is whether net-metered customers are paying the full cost of grid services. Some studies have demonstrated that the presence of revenue shifts does not necessarily imply that net metered customers are not covering their cost of service. Some recent studies of net metering suggest that regardless of lost contribution to fixed costs, a number of classes of net-metered customers have been paying more than it costs to serve them.[83,84] In contrast, other studies have concluded that net-metered customers do not cover their cost of service.[85] If as the evidence suggests that in some cases, net-metered customers are covering their costs of being served, while creating a revenue shift to other customers suggests that rates need to be better aligned with costs and benefits across the system.

A core driver of rates not tracking costs is the practice of allocating fixed costs in the variable portion of rates as a vehicle for recovering costs. In response to concerns created by net metering the Salt River Project, a publicly owned utility, was the first to restructure residential rates from the two-part rate (customer plus energy charges) to a three-part rate that includes a demand charge. The customer charge includes the cost of connecting to a customer's house and varies according to the size of the electric service. The energy charge is based on the variable cost of providing energy, and no longer includes fixed-cost recovery, resulting in a lower energy charge. The Salt River Project approach characterizes the demand (capacity) charge as a grid charge that will vary depending on the customer's peak use of electricity during peak hours.[86]

One concern in the adoption of demand charges is their historic use as a tool for price discrimination in industrial rate design.

> The usefulness of demand-charge rate structures as an instrument of price discrimination in the face of competition from isolated plants was known within the

industry and was accepted by early regulatory commissions as a justification for their use.[87]

Demand charges played a role in discouraging self-generation, which dominated utility generation until 1914 and remained half as expensive as utility-generated power in 1929.[88] Although the three-part rate schedule holds the promise of resolving some of the revenue issues associated with the deployment of solar power, concerns have been raised that its implementation is anti-competitive and an effort on the part of utilities to "monopolize the sun."[89] The solution to this concern depends on the answer to the fundamental question of whether the cost calculations upon which rates are designed are correct.

Proper evaluation of costs allow less complex methods of paying for DER. Given the nature of retail rates, it is only by chance that the price credited to customers for selling solar back to the system is correct. There is nothing inherently wrong with the two-part concept of net metering. And, if there are reasons for cost recovery in the variable part of the rates, there ways to maintain net metering without issues of subsidization and lost cost recovery. That is, to get the price paid for solar correct, whether higher or lower than the retail rate. As discussed below, that is in essence what Minnesota has tried to do with its Value of Solar tariff.

5.5 Getting the Price Right

Transformational policies have provided direction to utilities to create mechanisms that provide financial support for disruptive technologies. Frequently, these financial resources are provided in the form of a transaction in which the utility acquires a service and thereby provides a revenue stream for the investment in the disruptive technology (such as net metering providing revenues for solar). Acquiring efficient levels of these resources requires getting the price right by breaking down the formulas/calculations used and understanding the underlying costs and benefits associated with services provided by these technologies. It also involves clarity and transparency in where (jurisdictionally) prices will be set. Jurisdictional issues over price formation are increasing with the changing role of the customer. Historically, all transactions that dealt with the final customers were considered retail transactions regulated by State PUCs. Now, there is increasing uncertainty over whether some of these transactions might be considered wholesale transactions (sales for resale) that could or should be regulated by the FERC.

5.5.1 Where Price is Determined

Historically, there has been a "bright line" over the provision and pricing of electricity between Federal and State jurisdiction. State PUCs have jurisdiction over retail rates (e.g., sales to customers); the FERC (as did its predecessor, the Federal Power Commission) has jurisdiction over wholesale sales. That bright line is now blurring due to the changing dynamics of customers and the increasing role of centrally organized wholesale markets (e.g., regional transmission operators and independent system operators. In the past, electricity flowed from wholesale markets to retail markets—from generation, through transmission, to distribution, to the customer. Now, with the emergence of transactive energy (both responsive demand and customer generation), power flows from the customer back to the grid. Court decisions about two products, demand response and capacity markets to support resource adequacy, illustrate the blurring line between wholesale and retail pricing. Both products directly affect the efficiency and operation of the wholesale markets.

In May 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated FERC *Order No. 745*, the rule for pricing-demand response[ff] in organized markets. In Order 745, the FERC approved the use of demand response as a mechanism to pay customers to curtail consumption in order to reduce the market price of power, thus providing a new market equilibrium at a lower point on the supply curve. The Appellate Court found that FERC had exceeded its statutory authority to regulate wholesale sales, finding that Order 745 was a direct regulation of retail rates over which FERC lacks jurisdiction:

> Demand response—simply put—is part of the retail market. It involves retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption.[90]

In January 2016, the U.S. Supreme Court reversed the Appellate Court's ruling in FERC v. EPSA.[91] In doing so, it further clarified FERC's jurisdiction over pricing mechanisms that affect customers' new transactive role, finding that as long as FERC does not dictate retail rates, its policies can indirectly affect retail rates.[92]

The courts have already ruled in favor of FERC's ability to approve market mechanisms that support resource adequacy. In *Blumenthal vs. FERC,*[93] The D.C. District Court held that FERC had jurisdiction over market mechanisms (capacity markets) that were designed to achieve State resource adequacy objectives. In April, 2016, the court further reiterated the FERC's primacy over wholesale markets in *Hughes v. Talen Energy Marketing*[94] in which it rejected a Maryland program to provide support payments to generators because "it disregards an interstate wholesale rate required by FERC." The court left the door open to "encouraging production of new or clean generation through measures that do not condition payment of funds" on FERC regulated markets.

In addition to cases that clarify price, the court has further clarified the line between federal regulation of energy markets and states' ability to enforce their antitrust laws. In *Oneok Inc. v. Learjet Inc.*, the Supreme Court held that the Natural Gas Act, which, like the Federal Power Act, provides FERC with its statutory authority, does not preempt state antitrust suits aimed at pipeline companies' price manipulation. Justice Stephen Breyer in writing the majority opinion stated that the Natural Gas Act "was drawn with meticulous regard for the continued exercise of state power, not to handicap it or dilute it in any way."[95]

While the U.S. Supreme Court is clarifying these areas of jurisdiction, there is growing jurisdictional ambiguity with respect to the regulatory authority overseeing new technologies, including the following:

- Micro-grids, in which retail customers may take power from and deliver distributed generation power into a local network that, in turn, may purchase or sell it at wholesale to a distribution utility

[ff] Demand response is a mechanism whereby customers are paid not to consume.

- Energy storage, wherein end-users may charge energy-storage devices at retail rates and discharge and sell at wholesale
- Automated demand response, by which an RTO can signal retail customers to reduce demand or charge/discharge batteries or other storage
- Real-time pricing, which permits customers to increase or decrease energy use based on wholesale prices[96] The Distribution System Operator (discussed below) that acts as an interface between customers and wholesale markets.

In some cases around the country, market structures and mechanisms have been designed to maintain State jurisdiction over power markets. For example, interconnections are limited, with the Energy Reliability Council of Texas (the Texas power system) and surrounding states to secure Public Utility Commission of Texas' control over the State's electric sector. Jurisdiction and control will continue to play an important role in the design and efficacy of future business models.

5.5.2 The Importance of Product Specification

Part of getting the price right is knowing what is being bought. The goods in electric markets frequently have many dimensions. Products in capacity markets are a good example: they are used to support resource adequacy but what is the nature of the obligation that a generator takes on when it sells capacity? Does it take on the obligation to provide energy when the system needs it, or is it simply paid for owning steel in the ground (the power plant)? How does the cost of providing that service change with a changing obligation?

This section emphasizes the importance of product specification and cost by looking at two examples: frequency regulation and the use of retail rates for net-energy metering.

Frequency regulation is the maintenance of power systems at 60Hz. When frequency falls outside of a narrow band, the system experiences reliability problems; in the worst case, a blackout. With too much generation, the frequency increases; too little, and it decreases. System frequency is regulated by signals sent from power system controls every four to six seconds by increasing or decreasing the energy injected into the system. Before 2011, generators participating in frequency regulation (balancing system supply and demand over 5- to 10- minute increments) were paid by the independent system operators—and ultimately, customers, regardless of whether they followed the operator's signal. Order 755 required system operators to incorporate a resource's speed and accuracy into a performance-based payment.[97] The Order, although technology-neutral, was initiated because storage technologies capable of providing faster and more accurate frequency-response services than generators were increasing reliability without being compensated for the benefits provided. Some forms of energy storage are now cost effective compared with traditional generation technologies for providing balancing services.[98] Storage is displacing coal as a resource in the Pennsylvania-Jersey-Maryland Interconnection frequency-regulation market. Between January 2012 and December 2013, the share of frequency regulation from coal decreased from 34.7 percent to 12.3 percent, and fast-response resources (e.g., storage) grew from zero to 14 percent of frequency-regulation requirements by December 2013.[99]

Net metering also demonstrates the importance of getting the price right. As previously discussed, there is a divergence of views on the identification of appropriate costs. Much of the debate surrounding net metering has focused on whether the distributed generator is being over-compensated or under-compensated for the value of its generation. On the over-compensation side, some argue that DER customers do not pay for their use of grid services.[100] On the other side, there are those who argue that DER is undervalued by existing rate structures and the cost analyses that support it.

The valuation of DER is largely based on product and service definitions offered by different parties. The value of solar power incorporates two types of cost: direct, out-of-pocket costs and external costs such as the social cost of carbon. Many argue that net metering actually undervalues solar power because it does not include non-monetized benefits. Others argue that if utilities do not charge customers for non-monetized costs, DER should not be paid for those costs, either. Virtually all non-monetized benefits arise outside of the utility revenue requirement and are typically not costs paid by customers. In the absence of specific State legislation, PUCs are the arbiters for determining whether it is just and reasonable to pay DER owners for non-monetized benefits (externalities) and whether it is appropriate to charge non-participating customers for doing so.

A recent Minnesota statute created a value-of-solar (VOS) tariff option[gg] that defines elements of value that go beyond the typical utility elements of cost and provides a good example of the divergence of views on measuring costs.

> The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The Department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.[101]

The VOS tariff establishes a long-term fixed price based on its estimated present value over the contract term. Even with defined elements of cost for the VOS tariff, there are large differences among different interests in assigning value. Table 5.1 compares Northern States Power's (NSP's) estimate of the value of solar power to the estimates ultimately adopted by the Minnesota PUC. In this case, the public supported many non-monetized values, while the utility supported values that would be consistent with the ratepayer impact measure. The divergence in estimates would likely be greater if all values allowed by the legislation, such as a credit for locally manufactured or assembled energy systems, had been quantified and reflected in the estimates.

[gg] Adoption of the VOS tariff is voluntary for the utility and establishes a process for transitioning from net metering to payment based on VOS.

Table 5.1. Comparison of NSP Recommendations and Adopted Values[102]

Cost Component	Adopted Values	NSP Recommendations	Difference
Avoided Fuel Cost	$0.056	$0.045	$0.011
Avoided Plan O&M: Fixed	$0.002	$0.001	$0.001
Avoided Plan O&M: Variable	$0.001	$0.001	$0.000
Avoided Gen Capacity Cost	$0.034	$0.012	$0.022
Avoided Reserve-Capacity Cost	$0.003	$0.000	$0.003
Avoided Distribution-Capacity Cost	$0.014	$0.000	$0.014
Avoided Environmental Cost	$0.004	$0.001	$0.003
Avoided Voltage-Control Cost	$0.030	$0.013	$0.017
Solar Integration Cost			
Total	$0.145	$0.074	$0.071

Increasingly, such alternative approaches as the Minnesota VOS tariff are being explored. In New York, one proposal would adopt the EE cost-effectiveness tests that determine which resources are in the public interest.[103] The benefits and costs, such as impacts on distribution system operation and the ability to defer investment, are highly technical. Like the VOS process, some EE evaluation methods like the total resource cost test provide the ability to consider the value of externalities in the resource acquisition process, thus providing an established paradigm that could be followed if States chose to do so.

5.5.3 It's Time to Re-Evaluate Costs and Rates

Given the importance of rates not only as a tool for compensating utilities, but, increasingly, as a vehicle for providing price signals to customers who provide transactive load and DER, it is time for the Federal Government to facilitate a national review of retail rates. The last comprehensive national review of rates, the Electric Utility Rate Design Study, was conducted in response to PURPA pricing provisions that required utilities to consider marginal costs as a basis for retail rate design. The study was a nationwide effort for the National Association of Regulatory Utility Commissioners led by the Electric Power Research Institute – with the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. Ninety-nine reports were issued on a wide variety of topics, including rate experiences around the world, analysis of pricing approaches, the role of the price elasticity of demand, and methods of quantifying marginal costs.[104] These reports helped guide States in meeting the PURPA requirement to consider avoided costs in ratemaking and provided a well-developed knowledge base for evaluating alternative forms of cost analysis and rate design.

The U.S. Department of Energy has begun a process of evaluating the costs and benefits of DER, providing taxonomy of costs, and framing the disputes associated with valuation of each cost element.[105] As part of its integrated grid effort, the Electric Power Research Institute is developing a benefit-cost framework for quantifying the impact of DER on the distribution and bulk power systems.[106] Importantly, sharing information nationally on valuation of costs and methods of developing rates does not imply a nationally prescribed method of determining costs and rates; in other words, doing so is a State responsibility. A national effort can however reduce the transactions costs of developing information on a state-by-state basis.

Since the last national review of rates, there has been a great deal of innovation in the role of the customer, rate design, and technologies used to provide service to customers. Costs have shifted, new costs are being considered, and the importance of rate design has increased—both for engendering customer response and as a method of encouraging efficiency and DER.

6.0 The Scope of Distribution Utilities

6.1 Limitations on the Scope of Utility Activities

The scope of utility services defines the lines of business that it can pursue. Scope is constrained by regulations and legislation or can be limited by a utility's disinterest in a particular line of business.

Historically, investor-owned utilities (IOUs) were vertically integrated monopolies that owned generation, transmission, and distribution, and provided service to all customers within their franchise service areas. These monopolies developed synergistic lines of business that helped them grow and take advantage of economies of scale and diversity benefits.

There are two fundamental reasons for limiting scope. The first is to effectively prevent cross-subsidization of utility affiliate activities, in which ratepayers subsidize non-core utility activities. Congress passed the *Public Utility Holding Company Act* (PUHCA) to achieve that end in 1935. The second reason to limit utility activity is to protect competitive providers of power and services.

It has long been recognized that regulatory capture can be used to protect the economic interests of either regulated firms or competitors. For example, the City Fuel & Ice Company, a manufacturer and distributor of ice, tried unsuccessfully to enlist the New York Public Service Commission to thwart the Consolidated Edison Company's campaign to increase gas and electric consumption by offering rebates to customers for purchasing electric or gas refrigerators and turning in their iceboxes.[107] *The National Energy Conservation Policy Act of 1978*[108] restricted utilities from financing or installing residential conservation measures out of a concern for anti-competitive behavior on the part of utilities that would have an adverse effect on local contractors. The *Energy Security Act of 1980*[109] modified this provision by allowing utilities to finance the installation of residential conservation measures if the utilities used independent contractors to supply and install residential conservation measures. The issue of limiting the scope of utility activities also arose in the 1990s during retail electric market restructuring with limitations on utility provision of generation in favor of the market.[hh] Retail choice significantly modified the utility business landscape by allowing entry of new retail service providers allowing multiple entities to serve load over the local distribution infrastructure.

Thus, the issue of scope plays a significant role in molding the future of the distribution utility. This section focuses on PUHCA limitations and electric restructuring, as both introduce a systematic treatment of scope issues.

6.2 PUHCA and Industry Restructuring

The *PUHCA* had a profound impact on electric utility structure, regulation, and operations. It created a regime of financial regulation of holding companies to govern utility ownership and asset distribution. In 1934, before PUHCA was enacted, a handful of holding companies largely controlled the Nation's private

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[hh] In contrast, the Federal Energy Regulatory Commission did not require corporate unbundling of generation and transmission when it implemented an open-access transmission requirement, opting instead to implement behavioral measures to prevent utilities from favoring their own generation over competitors when providing transmission service.

utilities. Congress enacted PUHCA in response to “a pattern of widespread abuses by holding company systems, promoters, and underwriters.”[110]

The Act required the Securities and Exchange Commission (SEC)—the agency responsible for its implementation—to simplify and reorganize the complex structures of holding company systems. The heart of PUHCA was Section 11(b)(1), which directed the SEC to limit the operations of holding company systems to a “single integrated public utility system,” which, when applied to electric utilities, meant an interconnected system confined to a single area or region of the country. Section 11(b)(1) also directed the SEC to:

> …permit as reasonably incidental, or economically necessary or appropriate to the operations of one of more integrated public-utility systems, the retention of any business (other than the business of a public-utility company as such) which the Commission shall find necessary or appropriate in the public interest or for protection of investors or consumers and not detrimental to the proper functioning of such system or systems.[111]

The review of retention (and later acquisition) of non-utility assets or businesses became a test of the functional relationship of various activities to the utility’s core function of providing electric service. The Act addressed a number of issues related to the impact of non-core business on the provision of electricity, including whether the magnitude of the business activity was significant enough to deleteriously affect the holding company; the relationship of various business activities to the core business; and the presence of cross-subsidies to the non-core business (either directly or by penalties to the utility’s cost of capital).

Prohibitions on cross-subsidies among different lines of business and the simplification requirement compelled divestiture of non-utility businesses that were found to have no functional relationship to the core utility business. The divestiture requirement had a significant impact on the scope of utility; in particular, on the ownership of electric streetcar companies.

Samuel Insull had recognized the diversity benefits of electric streetcars (saving capital, fuel, and labor costs), but by 1935, streetcars no longer supported the utility’s core business of providing electricity. Streetcars had become unprofitable due to significant capital requirements for modernization. The aging infrastructure presented the potential for cross-subsidies, as the needed investment would have adversely affected the utility’s ability to attract capital for its core business.

Streetcars thus failed SEC/PUHCA review and were divested. The Act affected approximately 50 percent of the transit companies, which carried some 80 percent of passengers in 1931. In addition, more than 100 electric railways (both inter-urban and streetcar systems) were closed down or sold at extreme discounts.[112]

Although PUHCA was repealed in 2005, largely to enable non-utility and foreign-owned corporations to invest in electric utilities, it provides a framework for evaluating the lines of business that a utility might pursue. This framework could serve as a useful test of the future scope of utility activities. For example, there is a public policy dispute over whether utilities should provide electric vehicle (EV) charging stations. Before PUHCA was repealed, this line of business would likely have been permissible under the

SEC's Rule 58, which governs the acquisition of "an energy-related company" in the "ordinary course of business."[113]

6.2.1 Restrictions on Utility Scope in Industry Restructuring

The electric utility industry experienced upheaval again in the 1970s and 1980s due to losses of economies of scale, environmental regulations, coal strikes, natural gas shortages, the Three Mile Island accident, and oil embargoes, all of which fostered interest in restructuring the industry. Proponents of electric industry restructuring, and such marketers as Enron, which saw new business opportunities, pointed to the success of the restructuring of other industries, including airlines, trucking, natural gas, and telecommunications. This section describes how restructuring further limited the scope of utilities.

In the 1990s, industry restructuring and the creation of competitive electricity markets gained momentum with promises of potential benefits. For example, Representative Thomas DeLay (Republican-Texas) set out one such free-market vision: "Bringing electricity into the competitive world will unleash new products, greater efficiencies, business synergies, and entrepreneurial success stories."[114] One stunning prediction was that average residential electricity bills would decline 43 percent with customer choice.[115] Enron's Chief Executive Officer, Ken Lay, claimed before Congress that competition would result in annual savings of $80 billion per year.[116]

The expectation that competitive electricity markets would provide adequate electricity generation was buoyed by the success of non-utility generation as a consequence of PURPA. Furthermore, at that time, nuclear facilities had overrun budgets resulting in substantial disallowances that created financial difficulties for some utilities and caused the industry to become increasingly reluctant to build new generation. In states enthusiastic about restructuring, such as California, "Utilities had little interest in undertaking any significant new generation investments themselves under the existing regulatory compact. From their perspective, they could at best break even and then only if all of their expenses were judged prudent and reasonable by the [California Public Utilities Commission]. There was no upside potential and considerable downside risk."[117]

By 1996, at least 41 States, including California, New York, and Texas, had adopted or were considering plans to end utility monopolies and provide competitive service through new service providers.[118] The New York State Public Service Commission's (NYPSC's) 1996 Competitive Opportunities Order restructured the market and restricted the scope of utility activity.

> Our vision for the future of the electric industry in light of competitive opportunities includes the following factors: (1) effective competition in the generation and energy services sectors; … (3) increased consumer choice of supplier and service company….[119]

Restructuring greatly altered the electric utility business model by breaking up vertically integrated utilities and introducing competition and customer choice.[120] Utilities' divestiture of generation allayed concerns about anti-competitive behavior, such as cross-subsidies between affiliates and favored treatment of facilities in the new market. The introduction of competitive markets required three steps: (1) the establishment of a robust wholesale energy market with the creation of independent power producers; (2) open access to transmission facilities, the creation of an open-access transmission tariff, and the development of regional transmission organizations; and (3) the development of retail competition, which required unbundling utility rates into functional categories.

In the eastern United States, the three power pools that had coordinated inter-utility transactions were transformed into independent system operators (ISOs) (New York ISO, Pennsylvania-Jersey-Maryland Interconnection, and Independent System Operator of New England). In order to implement a wholesale power market, California created two entities to coordinate wholesale transactions and provide a market for competitive firms to buy and sell electricity: the California Power Exchange, which focused on economy transactions, and the California ISO, which focused on maintaining reliability.

On the customer-facing side of restructured markets, new load-serving entities offered a competitive alternative to utilities for retail sales competition. These entities work as intermediaries, purchasing power directly from generators or from the power market and selling it to customers via the distribution utility. In order to compensate for the use of distribution company facilities, electricity retailers and utilities unbundled costs.[ii] Customers pay the distribution company the unbundled cost of providing distribution services (e.g., wires, etc.) and make a separate payment to the load-serving entities for energy consumed.

Public utility commissions in restructured states frequently encouraged or required divestiture of generating assets, so that the integrated utilities no longer controlled their own generation. As was the case in New York, the primary rationale for divestiture was to break the economic tie between distribution and generation services. Between 1998 and 2001, utilities divested more than 300 electric generating plants in the United States, nearly 20 percent of total generating capacity.[121] In 1997, only 1.6 percent of U.S. electricity was produced by non-utility generation, rising to 25 percent by 2002 and nearly 35 percent in 2012.[122]

The creation of organized markets increased the efficiency of generation coordination, but the grand savings promised by Ken Lay and other advocates of restructuring did not materialize. Efficiency improvements have been achieved independently of divestiture in other jurisdictions; for example, in the Midcontinent ISO, where organized markets were overlaid on the traditional vertically integrated utility structure.

It is difficult to determine whether industry restructuring has benefited customers, as there is little analysis that demonstrates that electricity costs are lower in the current structure of short-term markets than with utility provision or long-term contracting. Uncertainty increases the cost of capital of competitive firms above that of utilities. Many significant merchant generator companies, marketers, and energy traders failed and reorganized in bankruptcy court, including PG&E National Group, NRG, Calpine, Dynergy, Enron, Reliant Energy, Utility.com, Mirant, Boston Generating, and Mission Energy. Some of these companies survived, some liquidated their assets, and others failed permanently. Ultimately, whether customers are better off depends on whether the benefits of competition outweigh

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[ii] Unbundling is a form of ratemaking in which each of the elements of providing utility service (generation, transmission, distribution, and billing) is identified and priced separately based on cost of service studies. Unbundled services are either competitive or residual utility services (e.g., services not provided by competitive suppliers, such as distribution of power).

the increased capital cost required to provide service from competitive firms that do not have access to a stable customer base.

In the case of industry restructuring, a confluence of factors drove utilities and regulators to pursue a competitive model: utilities' reluctance to invest in new generation after nuclear cost disallowances, success of restructuring in other markets, and the belief that the new model would reduce customer costs. Eighty years after PUHCA, and decades after the restructuring experiment began, distribution utilities are now facing new challenges that are prompting another industry upheaval and may again alter the scope of the utility business.

6.3 Energy Efficiency, Distributed Energy Resources, and the Scope of Distribution Utility Business Models

The distribution utility of the future must incorporate and accommodate the two disruptive technologies that are transforming customers into prosumers: energy efficiency (including demand response) and distributed energy resources. There are several models for investment into these types of resources. Some involve direct utility ownership, while others are based on an independent ownership. This section will present a number of options, and the section following will discuss methods for determining whether different activities fit into the business scope of the utility of the future.

6.3.1 Models for Provision of Energy Efficiency and Demand-Side Services

An essential question in drawing the future scope of the utilities is whether they will provide energy efficiency (EE) services. There are four basic approaches to the provision of EE:[jj]

1. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective EE) and administered by the utility
2. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective EE) and administered by a third-party operating under a State or utility program
3. A market-based approach, in which third-party providers seek profit by selling EE services to customers
4. A market-based approach, in which individual customer act in response to electricity price signals.

In the first two approaches, funds for programs are collected by the utility through customers' bills. The last two approaches are financed directly by customers. What follows are descriptions of different types of entities that provide EE services.

[jj] Energy efficiency standards have played a vital role in transforming the efficiency of available products. This section is concerned with the choice and acquisition of those products.

Utility Programs

Utility EE programs are part of a resource-acquisition process in which a utility plans for resources that it expects to need in order to provide reliable service. As previously discussed, regulation has adopted three basic methods to overcome disincentives that have discouraged utilities from pursuing EE: 1) rate mechanisms that allow utilities to recoup their expenditures; 2) mechanisms such as rate decouplingthat compensate the utility for lost margin due to reduced sales ; and 3) financial incentives that enable utilities to transform EE into a source of earnings, as opposed to lost opportunities for capital investment from which the utility would make a return on capital. In 2012, budgets for electric utility EE programs totaled $5.9 billion.[123]

Independent Entities

Some States use independent entities to administer EE programs. For example, Vermont does not rely on investor-owned utilities (IOUs); it relies entirely on the independent provision of energy services. In 1999, the State established Efficiency Vermont, the Nation's first statewide energy-efficiency utility. The utility is funded by a legislatively approved energy-efficiency charge collected as a volumetric charge (per kilowatt-hour) on all customers' bills. Its purpose is to invest in services and programs that save money and conserve energy. The fee is based on integrated resource plans that consider both environmental and economic costs.[124] The energy efficiency utility budgets are then set at a level to realize all cost- effective EE. Some states, such as New York, employ a blended approach, whereby some efficiency programs are implemented by the New York State Energy Research and Development Authority, and other programs implemented by the utilities.

Market-Based Providers

Some companies provide value by serving as the interface between customers and the market. Demand-response aggregators, such as Comverge, EnerNoc, and Viridity, aggregate customers to respond to market prices. Other types of energy service companies (ESCOs), including Ameresco and Schneider Electric, help customers save money and energy by implementing EE practices, sometimes in conjunction with utility programs.

Demand Response Aggregators

Aggregators are companies that group customers together to facilitate their participation in the markets. As previously discussed, demand response is a market mechanism by which customers are paid to curtail consumption. Its effect on system operations is equivalent to an increase in generation. Demand response has provided reliability services in a number of organized markets. In particular, demand response aggregators have brought together groups of customers in capacity markets. As a capacity resource, demand response customers, coordinated through their aggregators, reduce consumption when the system needs additional capacity to maintain reliability. The deployment of demand response will likely increase with better interoperability (the ability to communicate between the grid and sophisticated electric consuming devices).

Energy Service Companies

Energy service companies offer both private provision of EE services and a vehicle for implementation. They typically provide EE under performance contracts in which the ESCO guarantees energy and/or dollar savings for the project, linking ESCO compensation to the performance of the project.[125] Since

1990, ESCOs have delivered $30 billion in infrastructure improvements for greater efficiency.[126] Eighty percent of ESCO projects are in the public and institutional sectors. Performance contracts implement equipment and facility upgrades for clients that do not have access to capital, with little or no up-front investment. Approximately one-third of ESCO projects in the public and institutional sectors used utility rebates that provided roughly 16 percent of total project-investment costs.[127]

Customer Response

Some customers feel a moral imperative to protect the environment and the nation's energy security by becoming more efficient; others simply wish to reduce their electric bills. Customers respond to price and incentives to improve efficiency in two ways. The first is a short-run price response (and, increasingly, to behavioral prompts[kk]), reducing energy consumption using existing infrastructure. The second is investment in capital in such items as efficient appliances, sometimes leveraging utility rebate programs and governmental tax breaks to facilitate investment.

6.3.2 Models for Integrating Distributed Energy Resources into the Grid

A distributed energy resource (DER) can be defined as any small-scale, dispersed generation. This type of generation delivers power into the distribution grid near the load center. Typically, DER is on the customer side of the meter: the customer installs generation and ties into the grid via the distribution utility. Utilities can integrate DER using a variety of business models. These models fall into two main classes:

1. **Customer-side DER**: distributed generation located on the customer side of the meter, such as rooftop solar. This group encompasses models that include independent sales of DER products directly to customers, and utility-driven installations in which customers participate.
2. **Utility-side DER**: business models in which a DER provider enters into an agreement to provide power directly to the utility, with little-to-no customer involvement. In this model, the DER technology company acts as an independent power provider.

Today, most DER installations [ll] occur on the customer side, where the customers either invest their own capital into the DER system or enter into a pay-as-you-go arrangement with a DER provider in the form of a power-purchase agreement or a lease. [128] Except in rare cases of bypass, the customer remains connected to the distribution grid, which serves any load unmet by the DER. When the DER system produces power in excess of customer needs, that power may be sold into the distribution system. Sales to the interconnected utility could occur under a net-metering arrangement, a value of solar tariff, a feed-in tariff,[mm] a PURPA contract, or as a negotiated wholesale sale.

[kk] Such companies as Opower use behavioral economic techniques to elicit more efficient consumption from consumers. One such technique is to show lower levels of energy usage among comparable homes.

[ll] "Onsite industrial generation represents approximately 3 percent of current U.S. generating capacity and approximately 4 percent of total megawatt hours of electricity generated in 2012, the latest year for which final data are available. More than 90 percent of the industrial generation capacity is concentrated in five industries. Of these industries, chemicals, paper, and petroleum and coal account for more than 80 percent of onsite industrial generation; primary metals and food industries comprise the remaining 20 percent."

[mm] Feed-in tariffs are set prices paid by utilities to customers for production of renewable energy.

Customer-Side Models

Customer Ownership

In this model, the customer finances the installation, keeps any renewable energy credits associated with solar production, enjoys the tax benefits of the investment, and keeps the bill credit from net metering (or revenue stream from an alternative compensation scheme, such as a value-of-solar or feed-in tariff).

Power Purchase Agreements

Power purchase agreements (PPAs), standard contract vehicles for long-term power purchases from a third-party developer, are recognized by at least 24 States, the District of Columbia, and Puerto Rico.[129] In PPAs for solar power, developers contract with building owners to install photovoltaic (PV) systems in exchange for a long-term contract. The developer owns the DER; the customer pays a fixed price for the electricity produced. The customer is credited through net metering. This process enables customers to have generation installed at their homes without paying the capital cost of the installation. The PPA is, effectively, customer's long-term hedge for the purchase of electricity while taking on the risk of the value of the bill credit for energy sold to the utility. In the event that energy prices decline or there is a shift in rate design, the bill credit can decline (increase), leaving customers to pay more (less) for their PPAs than they would for power from the utility.

Utility Affiliate Model

Distributed energy resource providers, such as ConEdison Solutions, can be utility affiliates rather than independent companies. In this business model, the utility is allowed to invest capital in developing DER providers through an affiliate. This type of arrangement ensures continued competition between DER providers, despite the advantages that the utility-affiliate may have from being associated with the utility.[130] To level any potential advantage, State PUCs and the Federal Energy Regulatory Commission have adopted codes of conduct that bar affiliates from competing in markets in which their parent (franchised) utilities do business, or subject affiliates to special restrictions and oversight.

Utility-Provided Customer-Premises Model

Where allowed, utilities may offer DER systems to customers and, like other utility generation investments, include the capital cost in rate base. The utility (as opposed to an affiliate) is the supplier. In areas with high demand for distributed or renewable energy generation (e.g. rooftop solar panels), a utility can compete with independent DER providers. In this case, the utility can closely monitor generation and improve complex system operations issues resulting from DER. For example, Tucson Electric Power has proposed a new program to install solar panels on customers' rooftops. Customers would receive a fixed bill for the 25-year term in exchange for use of their roofs. Customers would also have the opportunity to purchase the systems at a price that reflects the system's age.[131] The Tucson approach nets the PPA payments and bill credit of a third-party PPA business proposition to provide customers with certainty about their future electricity costs.

Whenever the utility is the DER provider, the regulator must be cognizant of the potential exercise of market power. If the regulator believes that customers are better off with a combined market of utility and independent offerings, it should establish mechanisms to prevent anti-competitive behavior.

Utility-Sided DER Model

Utility-Owned DER

Utility-owned DER can be located either on a customer's premises or on utility property. Arizona Public Service Company has proposed locating solar panels on customers' premises, but on the utility side of the meter rather than the customer side (the array and the inverter would be utility property). In this case, the utility would engage in a lease to pay the customer for hosting the solar panels. [132] Similarly, in 2011, Public Service Electric & Gas Company was allowed to install up to 200,000 pole-attached PV units (40 MW) on utility poles connected directly to the secondary distribution system that feeds homes and businesses.[133]

Utility-Provided DER

Utility-provided DER is, essentially, small-scale utility-owned generation. The advantage is that the utility can choose to place these distributed installations in locations that provide the greatest value, where they concentrate to provide the most dispatchable resource, or where they spread the financial benefits of solar among a group that would otherwise miss them (e.g., low-income customers). This model alleviates the issue of high upfront and installation costs that leave customers unable to participate. With no upfront costs and lease payments for providing PV sites, this option could be appealing to customers because it provides cash flow and allows them to participate in the clean energy economy.

Third–Party Merchant Model

Independent third parties can connect DER directly to the distribution system with no on-site customer involvement. This type of arrangement is possible under a PPA between the project developer and the utility. In Minnesota, Xcel Energy recently contracted with Geronimo Energy to add 100 MW of 2–10 MW distributed solar installations co-sited with Xcel substations to add generation in peak hours at key load centers.[134]

Community Solar Model

The community solar model is an additional method of organizing the installation of solar facilities. In this structure, solar facilities supply power to multiple customers, enabling the placement and sharing of solar installations by a diverse group of customers. This model is mentioned separately because it can be developed via multiple ownership forms, including joint, municipal, and utility.

6.4 When Limitation of Scope Is Warranted

Past restrictions imposed on utility ownership of generation provide lessons for looking at the scope of the future business model. In particular, restrictions reinforce the understanding that what utilities can or cannot do will have a significant impact on customers. As the Enron collapse demonstrated, it is easier to promise benefits of alternative structures than it is to deliver those benefits to customers.

Prudent public policy decision-makers would ask whether and what future limitations on utility scope are warranted, and whether and how limiting utility scope benefits customers.

Regulation often seeks to rely on the market rather than regulatory mechanisms, as reflected by the NYPSC's decision to deregulate New York's electric sector, saying, "Market forces overall are expected to produce, over time, rates that will be lower than they would be under a regulated environment."[135]

In order to implement its image of competition, the NYPSC restricted utility ownership of generation.

> In any model under which the production of electricity is deregulated, it must be separated from transmission and distribution systems in order to prevent onset of market power.[136]

In its current Reforming the Energy Vision initiative, New York continues to favor market provision over regulated provision of services to customers.

Professor Alfred Kahn,[nn] perhaps best described as the late twentieth century's Dean of regulatory theory and practice and an early proponent of competition as an alternative to regulation, argued against limiting the ability of incumbent utilities and their ratepayers from benefiting from their advantages in the market:

> Protection of competition, not competitors—Government interventions must aim to provide fair competitive opportunities, not to protect competitors from efficient competition. Any attempt to deny incumbent companies the benefit of or handicap them in exploiting genuine efficiency advantages threatens to suppress competition and denies consumers its full benefits.[137]

Telecommunications deregulation took a different tactic than electric restructuring when it came to the ability of affiliates to provide competitive services. Unlike PUHCA regulations that focused on the relationship with the core utility business, telecommunications regulations focused on the ability to exercise market power. The Bell operating companies that survived the transition to competition, such as Verizon Communications, did so because they were permitted to offer such competitive services as Internet access, cable television, and cellular telephones.[138] AT&T re-acquired some Bell operating companies, including Pacific Bell and Southwestern Bell Company. Judge Harold H. Greene's 1978 Consent Decree, which provided the roadmap for breaking up AT&T, described the terms for allowing competitive services:

> According to the Department of Justice, the Operating Companies must be barred from entering all competitive markets to ensure that they will not misuse their monopoly power. The court will not impose restrictions simply for the sake of theoretical consistency. Restrictions must be based on an assessment of the realistic circumstances of the relevant markets, including the Operating Companies' ability to engage in anticompetitive behavior, their potential contribution to the market as an added

[nn]Alfred Kahn was a professor of economics at Cornell University, Chairman of the New York Public Service Commission, President Jimmy Carter's Inflation Czar, and Chairman of the Civil Aeronautics Board for which he oversaw the deregulation of the U.S. airline industry.

> competitor for A.T.&T., as well as upon the effects of the restrictions on the rates for local telephone service.[139]

Ultimately, the question is not what the utility affiliate is permitted to do, but which functions the utility itself is allowed to perform. Some basic questions should be addressed in the process of determining the scope of the utility:

1. Does prohibiting utility activity mean giving up diversity benefits or economies of scale and scope?
2. Do the benefits of competition, with its higher cost of capital, outweigh the lower cost of capital associated with the regulatory compact?
3. Which option provides customers with the lowest cost of service?

The role of utilities in providing DER is relevant to the problems of determining scope. Are customers better off or worse off in states that prohibit utility deployment of residential-scale PV systems? A significant portion of DER is PV installed under power purchase agreements. These agreements typically require a customer to enter into a 20-year contract with a solar power provider. The contract provides a fixed payment schedule, which is essentially a hedge against the price paid to the utility for service. The solar power provider finances the project, typically at a competitive cost of capital above that allowed for regulated utilities. Like customers with a utility-owned solar roof installation, customers with a PPA with a solar provider do not own the solar array.

California's policy is a hybrid approach, allowing net metering with third-party development through PPAs and utility investment in PV. State IOUs are allowed to own and operate solar PV facilities and execute solar PV PPAs with independent power producers through a competitive solicitation process.[140] California has also pursued a hybrid approach to utility/market provision that promotes storage technology that enhances grid optimization, the integration of renewable energy, and the reduction of greenhouse gas emissions, and explicitly provides a role for the utility. Under *State Law AB 2514*, the California PUC is required to establish procurement targets for the State's three IOUs to acquire viable and cost-effective storage. In October 2013, California PUC established procurement targets that required the three IOUs to procure 1,325 MW of storage by 2020, with targets divided among three industry segments: connected transmission, distribution level, and customer-side meter applications. In contrast with the State's policy on rooftop solar installations, utilities are allowed to own up to 50 percent of their cumulative targets.[141]

If the primary objective is to reduce greenhouse gases through renewable energy, then distributed renewable power may be a high-cost route to achieving greenhouse gas reductions. A recent study found that the cost-per-MW of adding 300 MW of customer-owned residential-scale solar power generation was twice that of utility-scale solar due to economies of scale from utility development. The cost difference further increased when compared to leased residential-scale systems.[142] The accounting of transmission, network reliability, and corporate overhead on the utility side is critically important, as are benefits that distributed solar generation might bring on the customer side.[143] From a customer perspective, it may not be possible to close this gap, as the cost of capital varies among service providers.

EV charging stations present another example of where utility scope comes into play. The utility, the customer, or a third party can own home EV charging stations. Does it make sense to prohibit electric utilities from providing EV charging stations? Although such a move seems to benefit competitive providers of charging stations, does the customer benefit? Customers will have to pursue and enter into private transactions without the benefit of a regulatory structure to oversee the quality of the interconnection. From the utility's standpoint, there are lost opportunities to either add charging stations into the rate base or to earn revenues associated with their installation. EV charging appears to pass the PUHCA criteria discussed above: investment in EV stations would be relatively modest and align with the core business of distribution (interconnecting load to the grid); PUCs could maintain an ongoing regulatory process to guard against cross-subsidization. In addition, there could be the potential for utilities to integrate operation of charging stations with the EV as a form of distributed storage. Ultimately, State PUCs will need to evaluate whether customers are better off with or without utility participation in these activities, and where utility involvement ends. An evidence-based approach to such decision-making would require transparent analytical methods, the design of which is discussed in more depth in the next chapter.

Decisions about options available to utilities and customers are sometimes made with a focus on protecting competitors, rather than minimizing consumers' costs. All sides will argue that their service is best for consumers and in the public interest, but their fiduciary responsibilities lie with their stockholders, not their customers. It is the regulator's job to analyze these arguments and forge business models that protect the public interest. California learned the lessons of protecting competitors over consumers during its early foray into deregulation. California utilities' obligation to serve was shifted from utility acquisition and power plant ownership to an obligation to purchase power through the spot markets.[oo] Utilities were kept from entering into long-term contracts that could have provided a hedge against volatile market prices. Consequently, 50 percent to 60 percent of customers' energy was acquired in un-hedged spot markets during the energy crisis. After the crisis, California re-created a regulatory structure with an active role for utility procurement, including a reinvigorated role for planning, preapproval of plans for acquiring power, and, if demonstrably beneficial to ratepayers, utility ownership of generation resources.[144]

There are alternatives that limit the scope of utilities while continuing to protect competition. Regulation provides a unique protection for utilities: anti-trust immunity. The State Action Doctrine is based on U.S. Supreme Court precedent, immunizing activity that would otherwise be subject to anti-trust prosecution.[145] There is a two-prong test to determine whether behavior is immune: behavior must be both consistent with State policy and supervised by a State agency. For utilities, the standard is safe and adequate service at just and reasonable rates, with supervision carried out by PUCs that determine the rates and terms of service.[146] Recently, with the restructuring of the electric industry, some states have backed away from policies in which a regulated monopoly is the preferred method of service provision and has increased their reliance on the market. One way to protect competition while enabling utilities to participate in new markets is for a PUC to limit the scope of State action immunity, providing legal recourse to competitors aggrieved by perceived unlawful exercise of monopoly power.

[oo] CA AB 1890 obligated utilities to purchase power through the PX and CAISO during a transition period.

The issue of utility scope will increase in importance with the complexity of electricity provision, including growth of DER, EVs, and other disruptive technologies.

7.0 The Path Forward

This paper has described the characteristics, factors, and players of the electric utility landscape and issues confronting the distribution utility model, as well as provided information to new and old stakeholders involved in the current discussions about utility futures. A snapshot of the history of the utility business model, milestones, and significant transitions has illuminated key issues. This chapter addresses the evolving current situation and the intertwined problems that government, industry, and stakeholder input must resolve to foster development of a distribution utility model that serves the public interest today and in the future.

7.1 Adapting the Distribution Utility Business Model

The electric distribution utility, more than ever previously experienced since its inception in the 1880s, now faces a fundamental transformation. The current evolution is being driven by the emergent role of the consumer as prosumer, and by such new imperatives as resilience, a cleaner energy future, and security. Additional investments to support enhanced services are required, including the new transactive role for customers and the higher levels of reliability that will support the digital economy.

It is critically important to understand that alternative utility business models and regulatory practices are inextricably linked. Modification of the utility business model must be acceptable to State regulators, responsive to customers, and financially tenable to utility shareholders, all while supporting innovation (whether by the utility or third-party providers). The business model is part of a triad of interrelated elements that determine the nature of customer service:[147]

1. The **regulatory structure** defines the products, services, and service providers that will be subject to a spectrum of regulations that include prices and specific attributes of service that utilities offer in order to meet diverse customer needs.
2. The **economic structure** defines the organization of the utility space: the types of firms that provide service, and the mechanisms and structures for cost recovery (e.g., markets and cost-of-service regulation including such variants as performance-based ratemaking and decoupling) that will influence the amount of capital that will be invested.
3. The **business model** defines products sold, process of selling and customer interaction, the ultimate form of pricing/terms of service, and internal organization to support the model.

Dr. Peter Fox-Penner, a thought leader providing expert services to the electric utility industry, has identified two alternative models that can evolve logically from current market structures: the Smart Integrator Model and the Energy Services Utility. The Smart Integrator is an operator of the distribution grid in much the same way that an independent system operator (ISO) operates wholesale power markets. It is a platform for transactions but does not participate in energy transactions. The Energy Services Utility shares the basic functions of the smart integrator, but is also a provider of services. It is an extension of the vertically integrated utility. Figure 7.1 describes the impact of competition and smart grid networks on each of these business models.

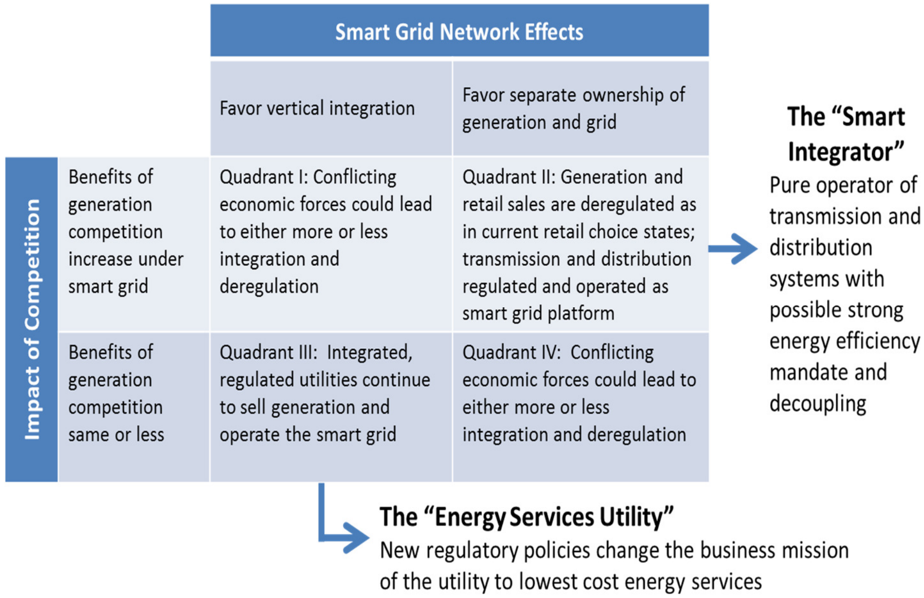

Figure 7.1 Impact of Competition and Smart Grid Network Effects on Utility Business Models

Source: Adapted from Fox-Penner, Peter. 2010. "Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities." Island Press. Reproduced with permission..

The models articulated by Fox-Penner frame two extremes of the future distribution utility model. The remainder of this chapter focuses on issues and methods to facilitate stakeholders and policymakers in determining where on the quilt of alternatives the new distribution utility model will fall.

7.2 Guiding Principles for Transforming Distribution Utilities

Guiding principles can provide a framework for evaluating alternative models. These principles serve as a starting point and context for discussion among stakeholder groups, and more clearly frame the debate about the future role of the distribution utility.

The role of guiding principles is determined by each state's restructuring action, and some states, including New York, California, Minnesota, and Vermont, have already begun the process. New York has introduced Reforming the Energy Vision (REV). The Minnesota e21 Initiative began as a stakeholder-driven process to develop a regulatory framework that was then formalized in a Minnesota PUC inquiry. The California legislature has provided direction and mandates to the California Public Utilities Commission through *California Assembly Bill 32*, which requires aggressive reductions in greenhouse gas emissions[pp], and through *California Assembly Bill 327*, which enhances methods of distribution planning.[qq] Vermont's, State legislature has empowered the Vermont Public Service Board to investigate

[pp] California Assembly Bill 32

[qq] …such as CA AB 327. The California PUC has promulgated a number of proceedings guided by legislative mandate and executive orders that take deep dives on a number of specific issues, including community choice aggregation, energy storage procurement targets, energy efficiency, EV sub-metering, demand response, distribution grid development and transparency, smart metering, and the California Solar Initiative.

and approve alternative forms of regulation. These restructuring actions illustrate the use of guiding principles by decision-makers.

The New York State Public Service Commission (NYPSC), inspired by the potential transactive role of customers, initiated its REV process to overhaul the role of the distribution utility in the State.

> **R**eforming the **E**nergy **V**ision will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management and operation of the electric system.[148]

One of the first steps in the New York REV process was the development of guiding principles in a collaborative process reviewed and approved by the NYPSC.

In Minnesota, e21 stakeholders collaboratively developed guiding principles. The Minnesota process followed the four-step "virtuous cycle of energy diplomacy:" convene, inform, agree, and act. The process included the State, ratepayers, cities, non-governmental organizations, clean-energy companies, utilities, and the Minnesota Chamber of Commerce.

Table 7.1 compares guiding principles for the Minnesota e21 process with those adopted by the NYPSC in its REV process and Vermont's legislative mandate. The e21 process describes guiding principles for an energy services utility, whereas New York provides principles for a smart integrator model and Vermont creates a new regulatory compact.

The principles established by all three States reflect many of the same interests. For example, the NYPSC Order calls for the promotion of investments and market activity with "consideration to identified externalities." Minnesota framed externalities more broadly as "align[ment] … with State and Federal public policy goals" that acknowledge the State's aggressive renewable generation goals. Each set of principles stresses the importance of innovation; however, there are differences among the principles that might be adopted for an energy services utility as opposed to a smart integrator model. Minnesota expressly calls for the "predictable recovery of utilities' fixed costs that are not necessarily dependent on commodity sales." New York does not include recovery of utility costs in its list of principles, but does include the concept of "fair and open competition." Indeed, the New York experience with retail access is reflected in its concerns about market power, whereas the Minnesota and Vermont principles are oriented toward utility provision of service and a more customer-centric business model.

Table 7.1 Comparison of Guiding Principles of Minnesota e21 Process. New York REV Initiative and Vermont

Minnesota e21[149]	New York REV[150]	Vermont[151]
1. Align an economically viable utility model with State and Federal public policy goals. 2. Provide universal access to electricity services, including affordable services to low-income customers. 3. Provide for just, reasonable, and competitive rates. 4. Consistent with No.2 and No.3 (above), align payments to and by participants with the costs and benefits they impose on and provide to the system. 5. Enable the delivery of services and choices that customers' value, and compensate utilities, customers, and service providers for the full range of services they provide. 6. Allow for timely and predictable recovery of utilities' fixed costs that are not necessarily dependent on commodity sales. 7. Encourage and enable electricity users to take advantage of all cost-effective energy efficiency and other demand-side management opportunities. 8. Facilitate innovation and implementation of new technologies, and delivery of new energy services. 9. Assure system reliability, and enhance resilience and security, while addressing customer privacy concerns. 10. Foster investment that optimizes the system's economic and operational efficiency.	1. Provide timely and consistent access to relevant information by market actors, and public visibility into market design and performance. 2. Make market rules and technology standards uniform statewide to encourage liquidity and participation. 3. Balance market innovation and participation with customer protections. 4. Reduce volatility and system costs, and promote bill management and choice. 5. Develop distributed system provider procurement tariffs to minimize the potential for market power. 6. Maintain and improve service quality, including reduced frequency and duration of outages. 7. Enhance system ability to withstand unforeseen shocks, including physical-, climate-, or market-induced, without major detriment to social needs. 8. Design level-playing-field incentives and access policies that promote fair and open competition. 9. Reduce data, physical, financial, and regulatory barriers to participation. 10. Promote diverse product and program options in a competitive market, including financing mechanisms to increase the value of those options. 11. Fair valuation of benefits and costs—include portfolio-level assessments and societal analysis with credible monitoring and verification 12. Align distributed system provider market operations and products with wholesale market operations to reflect the full value of services. 13. Promote investments and market activity that provide the greatest value to society, with consideration given to identified externalities. 14. Incorporate emission regulations and public service commission policy determinations for local distributed energy resources impacts. 15. Ensure consistency across regulatory objectives and requirements.	1. Establish a system of regulation in which companies have clear incentives to provide least-cost energy service to customers. 2. Provide just and reasonable rates for service to all classes of customers. 3. Deliver safe and reliable service. 4. Offer incentives for innovation and improved performance that advance State energy policy, such as increasing reliance on Vermont-based renewable energy and decreasing the extent to which the financial success of distribution utilities between rate cases is linked to increased sales to customers and may be threatened by decreases in those sales. 5. Promote improved quality of service, reliability, and service choice. 6. Encourage innovation in the provision of service. 7. Establish a reasonably balanced system of risks and rewards that encourages a company to operate as efficiently as possible using sound management practices. 8. Provide a reasonable opportunity, under sound and economical management, to earn a fair rate of return, provided that such opportunity is consistent with flexible design of alternative regulation and includes effective financial incentives in such alternatives. 9. Share savings that result from alternative regulation with ratepayers.

7.3 Moving from Guiding Principles to the Distribution Utility of the Future

7.3.1 Enhanced Role of Planning

Planning can be used to investigate alternatives and chart a path to achieve desired goals. The nature of electric utility planning has changed significantly over the past 30 years. Traditional utility planning focused on resource adequacy, assuring that there would be adequate generation to meet the forecasted customer needs. The introduction of demand-side management fostered the development of a new model, integrated resource planning (IRP), that fundamentally changed the planning process by introducing demand-side resources (e.g., energy efficiency) as an acceptable method of achieving resource adequacy objectives. IRP is a valuable tool for incorporating guiding principles in planning for the distribution utility of the future. Distribution resource plans (DRPs) provide a vehicle for exploring the many choices associated with the provision of distribution service and the role of the distribution utility. Future planning must be a nimble, ongoing process that monitors progress and problems, and adjusts to feedback and new circumstances.

The planning process provides a record of regulatory decision-making on broad policy issues, a forum in which to address those issues and specific investments. This process is not a bi-lateral conversation between the regulator and the utility—it must include all stakeholders with an interest in the outcome of the planning process, as it is in the public's interest to understand the deliberations and their implications. Broad participation requires access to utility data (e.g., line loadings on the distribution system) and analytical tools (e.g., production costing and financial models), so that differing options can be evaluated on an equal basis. Ultimately, the regulator is the arbiter of the planning process.

Although there can be several paths to developing a plan, the various alternative approaches share a number of common features. These include:

- Articulation of future needs
- Evaluation of alternatives
- Identification of new functions and an institutional framework for accommodating them
- Delineation of the scope of the utility
- Assessment of rate design and recovery mechanisms
- Analysis of the plan's effects on utilities' financial health
- Assessment of whether the plan supports or is a barrier to innovation.

One thing is certain: the distribution utility of the future will operate differently than it does today. It will increasingly rely on local resources—either customer behavior or physical resources (e.g., storage), as a substitute for building new distribution capacity. The Consolidated Edison Company of New York has saved customers more than $200 million in transmission and distribution expenses over the past decade by leveraging the transactive role of customers through demand-side programs.[152] Therefore, newly devised plans must consider and prepare for dramatic increases in information flow and include the analysis required to support the transactive role of customers.

Planning must also consider unambiguous policy objectives and mandates, including specific investments to increase the resilience of the power system. For example, after Superstorm Sandy crippled the mass transit system serving the New York metropolitan area, New Jersey pursued the development of a microgrid to provide highly reliable power to New Jersey Transit during natural disasters. New Jersey is implementing this project with technical assistance from the U.S. Department of

Energy and Federal financial assistance.[153] Microgrids, such as the proposed New Jersey Transit grid, employ their own generation and are able to operate autonomously to help the grid recover from major failure and reconnect. Although the merits of such an investment are obvious, it does raise a number of issues that relate to the utility business model. Should the utility participate as an equity partner in such a project? What is the role of the distribution utility in coordinating the microgrid's generation? What new products are required for the distribution utility to serve the microgrid and how will those rates be determined? A planning process provides the opportunity to explore the issues of implementing State policy.

California has led the Nation in creating a new role for distribution planning. In 2013, *California Assembly Bill 327* required that "[e]ach electrical corporation, as part of its distribution planning process, shall consider non-utility-owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost."[154] California's investor-owned utilities are required to file DRPs with the California PUC that include "the need for investment to integrate cost-effective [distributive energy resources (DER)] and for actively identifying barriers to the deployment of DER such as safety standards related to technology or operation of the distribution circuit."[155]

Analysis of the optimal location of DER enables utilities to avoid unnecessary investment in distribution infrastructure. Making these investments requires developing new methods that allow the utilities to define locational benefits of DER. The DRP goes beyond the analysis of physical infrastructure, requiring that "the planning process must also be sufficiently transparent to support the development of DER alternatives that meet current and future system requirements,"[156] and to provide "information needed by third parties to plan for effective market participation."[157]

7.3.2 The Need to Coordinate Transactive Energy

A core function in either the energy services utility or smart integrator model is the role that the distribution company plays as a communications network. Communications are required to allow the evolution of transactive energy and the transformation of electricity consumers into prosumers. Enabling power electronics provides three vital communications functions: monitoring, control, and metering.

Monitoring distribution system operation is growing more complex as flow on the system changes from one-way to bi-directional flows between customers and the grid. In addition to the changing role of consumers, power electronics are also providing increased control over distribution circuits. The complexity of transactions increases the need for a meter that can both communicate with customers and record their energy production and consumption behavior. The net effect of the dramatic increase in the number of points of monitoring, control, and metering is the need to develop new information-management capabilities.

A more advanced distribution system will have to communicate to different devices in different time horizons, including phasor measurement equipment that monitors real-time electricity flows 60 times per second, and advanced meters that provide and collect information in 15-minute intervals.[158] It is reasonable to assume that the distribution system, which currently handles tens of thousands of information nodes, will have to handle tens of millions or hundreds of millions of nodes.[rr] This is a three to four orders of magnitude increase in the number of endpoints to be controlled or coordinated over what is common now.[159] Accommodating this increase in information flow will require new information-management systems and the infrastructure to support these systems. Complicating the development of new information-management systems is the need to maintain cybersecurity—it is critically important to protect the network from malevolent acts.

Thus, the emerging information challenge of coordinating the distribution system has led to calls for the creation of a distribution system operator (DSO). The DSO would be responsible for "balancing supply and demand variations at the distribution level, and linking wholesale and retail market agents—all while maintaining the traditional role of the system operator as a custodian for distribution system reliability."[160] DSOs would become the interface between the customer and the ISO, while the ISO would coordinate wholesale transactions, including energy and capacity purchases from generation. DSO and ISO would both maintain reliability and optimize operations at the distribution system level.

Figure 7.2 shows the electrical connections between the balancing authorities (e.g., ISOs) and customers. Generation and load directly connected to the transmission grid, as well as import-export points with neighboring balancing authorities, are assumed to exist within the balancing authority/transmission system operator, but are not shown because the focus of the diagram is transmission and distribution interfaces. The diagram does not preclude the possibility that distribution-connected load or generation could have transactions in the wholesale market operated by the transmission system operator—the DSO would still have to manage reliable distribution system operations to support such transactions. Electrically, all such transactions require some supporting functionality on the part of the DSO, even if it has no role in the business side of such transactions.

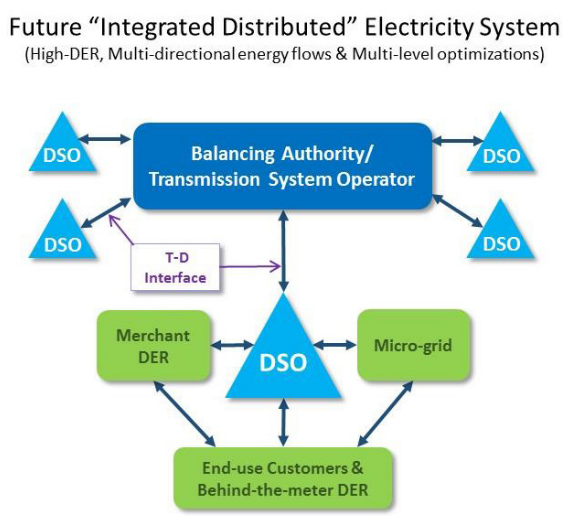

Figure 7.2 Integrated Distributed Electricity System with DSO

Source: Kristov, L, DeMartini, P. 2014. "21st Century Electric Distribution Systems Operations," Reproduced with permission.

[rr] The number of nodes exceeds the number of customers, because the calculation presumes not just transactive sites, but transactive devices inside those sites, and so is the outer limit of what may happen.

The New York REV process is developing the concept of the distribution company as an integrator of energy services. In this process, a new construct, the distributed service platform provider, the New York term for DSO, is under consideration. A significant difference between the distributed service platform provider and the traditional distribution utility is the new role as a transactional platform for a distribution-level market as a functional center called the distributed system provider (DSP).

> Ultimately, the DSP will synthesize system planning, grid operations, and market operations to promote the efficient and effective adoption of DER on the distribution system, with the goal of enhancing system efficiency, reducing long-term infrastructure costs, and engaging private capital in meeting customer energy goals.[161]

Two issues of scope come with the emergence of the DSO. The first relates to ownership of the DSO, the entity that will organize the operation of the distribution system. The second is which entities are allowed to participate in DSO activities (e.g., whether utilities are allowed to own distributed resources and their role in providing energy-efficiency resources). Policymakers should consider these questions when drafting new regulations for distribution utilities and alternative entities.

7.3.3 Grid Architecture as a Planning Tool

The intricacies of modern grid systems have long surpassed the capabilities of traditional methods of managing complexity. Paradigms such as system of systems and interoperability, while useful at certain levels, are not sufficient to support changes being contemplated in response to such emerging issues as the high penetration of DER. The relationships among technology, business, and regulation of the grid can be more easily understood from the standpoint of grid architecture, a discipline developed to enable a wide range of stakeholders to have a shared understanding of the grid and propose changes from multiple viewpoints simultaneously.[162] In this approach, the grid is viewed as a network of structures, as shown in Figure 7.3.

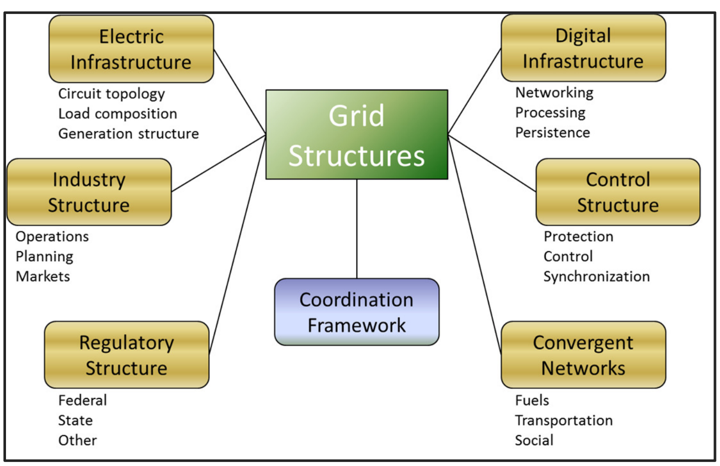

Figure 7.3. Network of Structures Model of the Grid

Source: Jeffrey D. Taft. 2105: System Architecture as a Tool for Managing Complex Systems: Application to Electric Grids. PNNL-SA-109838. Reproduced with permission.

Grid architecture provides a method of evaluating options analytically in relation to the set of qualities, properties, and priorities set for it by the stakeholders. Its primary uses are:

- Managing complexity, and, therefore, risk in making changes to the grid
- Determining the consequences of changes across the set of structures shown in Figure 7.3
- Enabling stakeholder communication around a shared vision of the future grid
- Identifying essential structural limitations and the minimum changes needed to enable new capabilities
- Modeling value streams before significant investments must be made
- Locating gaps in technology, regulation, and operational models in light of emerging trends and proposed changes.

More than anything else, grid architecture produces *insight*. As a simple example of how grid architecture illuminates key issues, consider the before and after diagrams of control and coordination in Figure 7.4. The coordination diagram illustrates how operational flows work in two scenarios in the first, distribution companies are largely bypassed, which could lead to eventual reliability issues as DER penetration increases. In the second, flow through the DSO resolves the ambiguity about reliability while potentially improving scalability and security.

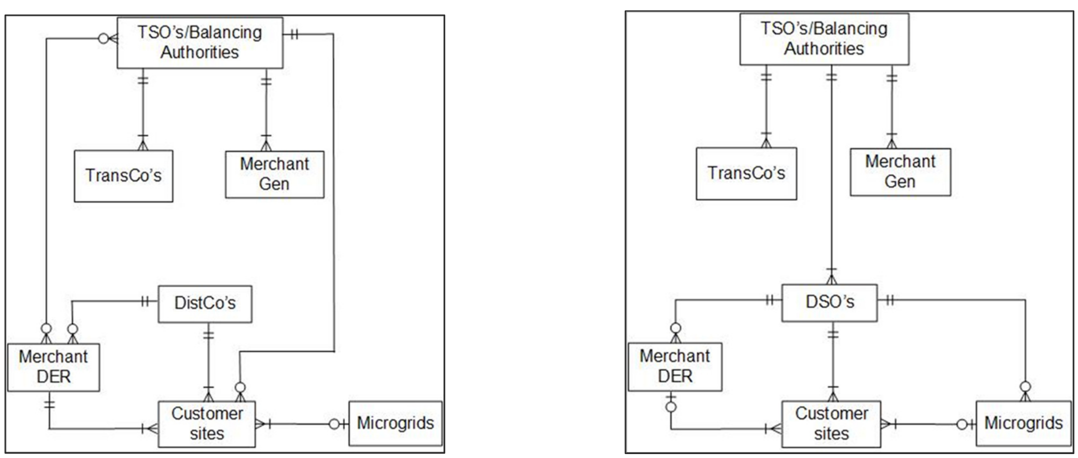

Figure 7.4. Comparison of Coordination Flows for Traditional and DSO Industry Structures

Source: Adapted from Jeffrey D. Taft. 2015: System Architecture as a Tool for Managing Complex Systems: Application to Electric Grids. PNNL-SA-109838. Reproduced with permission.

This coordination framework has clarified interaction models for traditional distribution provider and DSO models in high-DER-penetration environments with dual (e.g., ISO and DSO) markets. This, in turn, clarifies value flows, system interfaces, and market/control integration structures, and illuminates regulatory jurisdiction and market rule design issues.

Grid architecture is a valuable tool for augmenting efforts in the regulatory design of future business models, grid planning, market and control implementation and integration, standards development, and technology research.

7.3.4 Scope of the Distribution Company

Future utilities will fall between the two fundamental types of distribution companies, the smart integrator and the energy services utility. Each utility has a different starting point determined by its current regulatory structure and whether it provides unbundled or integrated service. At least three issues of scope will frame the future distribution utility business model: ownership and control of the DSO, ownership and provision of facilities, and services on the customer side of the meter.

Ownership and Control of DSOs

As previously discussed, information requirements associated with the transactive role of customers, combined with sophisticated power electronics that facilitate the reliable operation of the distribution system, will require a new control infrastructure. The DSO can function as a separate entity or as a new function within the utility. Whether a distribution company should own and operate the DSO is subject to debate. Market advocates contend that:

> …the best way for a utility to embrace new innovations without disruption to the grid is to have the distribution utilities transfer their operations to an independent distribution system operator akin to an independent system operator or a regional transmission organization in the bulk transmission system … The regulated utility will continue to maintain the distribution assets and rate-base obligatory grid investments under established protocols. It will also retain billing function to its customers for distribution service. …allowing the current grid owner (the utility) also to operate the distribution grid presents a strong conflict of interest, especially if optimizing the use of those assets may reduce the need for grid expansion and utility investment. The grid operator has clear incentives to favor increasing the utility's assets rather than encourage customer-owned DER."[163]

The creation of the independent distribution system operator is based on a regulatory imperative that separates asset ownership from operation. Some might argue that the independent ownership (typically a non-profit structure) of independent system operators is precedential for the ownership of the DSO. However, the role of coordination is somewhat different in the wholesale market, because power flows over a network with many owners. In contrast, in the distribution system, power typically flows over a network with a single owner.

The NYPSC recognized the importance of the distribution company's role in maintaining reliability in supporting its role as owner and operator of the DSO. In effect, the NYPSC's findings are based on economies of scope between reliability functions and the role of the DSO.

> Utilities are responsible for reliability, and the functions needed to enable distributed markets are integrally bound to the functions needed to ensure reliability. Technology innovators and third party aggregators (energy service companies, retail suppliers and demand-management companies) will develop products and services that enable full customer engagement. The utilities acting in concert will constitute a statewide platform that will provide uniform market access to customers and DER providers.[164]

> Having the utility expand its responsibility to include DSP functionality enhances the opportunity for integrated operation of the distribution system and for realizing the economic value of DER investment.[165]

Provision of Services on the Customer Side of the Meter

Beyond its historic role in delivering power to customers, the distribution company can provide two general classes of competitive services on the customer side of the meter: energy efficiency (including demand response) and distributed generation. Both are subject to evaluation in distribution resource plans and can act as a substitute for investment in distribution infrastructure. Which entity is best suited to provide the services? At issue is a tradeoff between economies of integration at the utility level combined with a lower capital cost, versus thought that the market is a preferred provider.

This confidence in the market is reflected in recent limits imposed by the NYPSC on the ability of the utility to own DER:

> First, as the platform provider, utilities will not participate as owners of DER where a market participant can and will provide these services. … DER will remain a non-utility service provided by the competitive market.[166]
>
> The basic tenet underlying REV is to use competitive markets and risk-based capital (as opposed to ratepayer funding) as the source of asset development. On an *ex-ante* basis, utility ownership of DER conflicts with this objective and, for that reason alone, is problematic.[167]

However, in making this finding, the NYPSC left the door open for utility ownership if "competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative" or if "a project will enable low- or moderate-income residential customers to benefit from DER where markets are not likely to satisfy the need."[168] Thus, the NYPSC is following California's lead, discussed earlier, in which California utilities are able to provide generation resources if utility provision is demonstrably preferable to that of the market.

The debate surrounding whether a distribution company ought to provide efficiency services closely parallels that of whether a utility ought to provide energy-efficiency services. Ultimately, the question is whether the tenet of the benefits of competition compared to utility provision that New York and other jurisdictions rely on is supported by empirical evidence. The competitive experiment has been ongoing since the late 1990s; however, there has been little analysis of whether customers have benefited. The evidence suggests that competition in the provision of retail service has created increased concerns related to customer protection. In announcing a plan to protect residential and small commercial customers in New York from unfair business practices, Governor Cuomo cited examples of energy service providers charging customers from two to eight times the rates thatincumbent utilities charged.[169]

Clearly, significant investment is needed to transform the U.S. electric system to meet the modern customers' potential consumption, achieve resilience and greenhouse gas objectives, and deploy EV charging stations to electrify transportation. Analytical approaches are required to evaluate whether customers are better off with competition, utility provision, or both. Additionally, PUHCA rules provide guidance. The AT&T Consent Decree also provides guidance from an industry that restructured, incorporated utility provision, and improved the welfare of its customers. Furthermore, part of the issue associated with utility participation in potentially competitive activities is whether PUCs are conveying State action immunity for anti-trust prosecution. The decision on the nature of the entity that will provide distribution services (e.g., provision of DER) will have significant societal effects beyond those of the competitive firms that are protected by limitations on utilities. Ultimately, a prudent decision must be based on evidence, not supposition.

7.3.5 Rates and Planning

Rates are a vital mechanism for implementing a distribution plan, which must perform three fundamental roles: (1) achieve cost recovery that both compensates utilities and provides them with incentives to achieve specified goals, (2) provide customers with incentives to reduce consumption and self-supply electricity, and (3) create revenue streams for third-party providers (e.g., polar providers) through net metering.

James C. Bonbright's three primary objectives (discussed previously) for ratemaking remain relevant. The first objective allows utilities to earn a fair return on invested capital. The second requires that the burden of rate recovery be fairly spread among the beneficiaries of services provided. The third objective is the efficiency of rate design (e.g., rates should provide efficient price signals for customer consumption decisions).

Cost analysis in rate design should track costs used in planning. An important issue in the planning process is whether the costs on which the plans are based are appropriately defined for the services rendered to and by customers. As previously discussed in the context of net metering, there are divergent views as to the appropriate elements of costs and their quantification. Reliance on different cost concepts not only affects rate design, but also affects the desired plan. The concept of higher rates to encourage conservation stems from the fact that social costs (environmental externalities) associated with the production of electricity are not reflected in market prices. In this case, prices based on market prices are not efficient from a societal standpoint. This divergence of private and social costs highlights the importance of clarity and the need for transparency of the costs used in planning, rate design, and cost recovery. At this point, information on costs is highly fractured, with different jurisdictions using different cost perspectives. A national review of the way costs are currently used, and how definitions and estimation methods may change, will help bring clarity to the choice of costs used for different purposes.

In addition to the price signal to customers, the rate design process also provides behavioral incentives to the utility. Doing so often involves developing new ways for utilities to make money. In a recent REV "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework" [170] the NYPSC established a number of new performance-based incentives called Earnings Adjustment Mechanisms (EAMs). The EAMs are designed to better align utility financial incentives with priority objectives, such as: system efficiency, energy efficiency, improved data access, and interconnection. Furthermore, the order established a new revenue stream Platform Service Revenues (PSRs) that enables utilities to earn revenues from operating and facilitating distribution-level markets.

7.3.6 Financial Implications of Distribution Utility Transformation

The electric utility industry has been accommodating new disruptive technologies and industry structures since the 1970s. One key metric of transformation is utility credit worthiness. Figure 7.5 illustrates the continued degradation of utility credit quality in the context of the changing nature of regulation and the utility business. In 1970, just prior to the restructuring events that altered the industry, the vast preponderance of utilities had credit ratings in the A range. By 2011, electric utility credit quality had declined, with more than 70 percent of utilities rated below the A range. In addition, the average quality in the A range deteriorated, with no utilities maintaining a AAA rating.

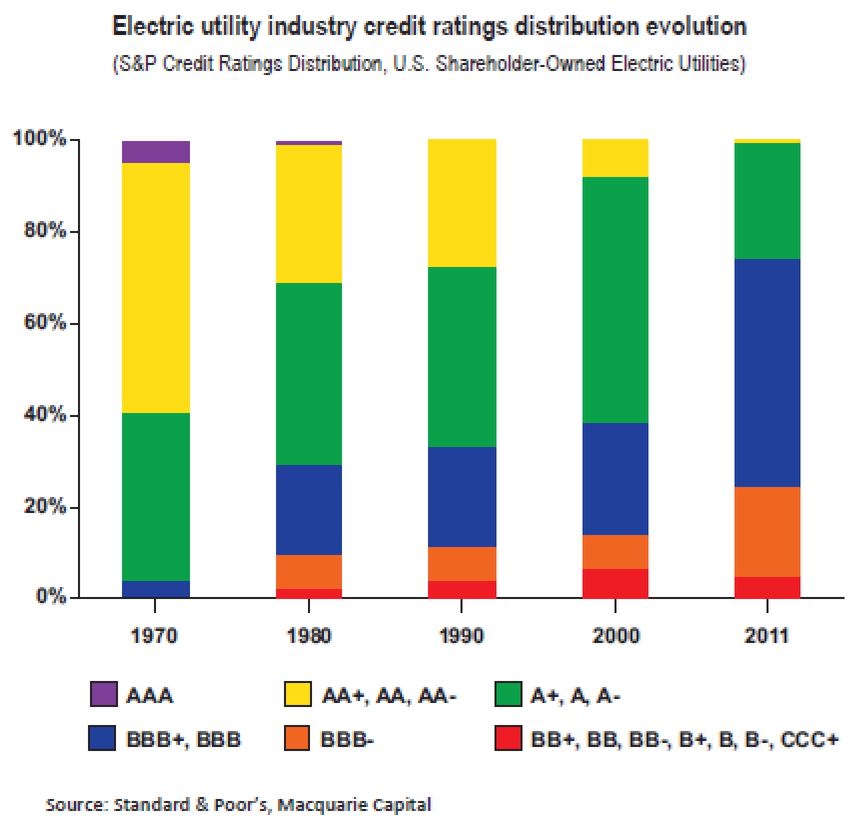

Figure 7.5. The Decline in Electric Utility Quality

Source: Reproduced from Peter Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," prepared for Edison Electric Institute, January 2013. Reproduced with permission.

Declining credit quality in the utility industry has cost implications for customers. Depending on a utility's capital requirements, a degradation in credit quality can impose increased costs on customers. It is prudent for State PUCs to evaluate the impact of decisions on utility scope and ratemaking on the utility's financial health and creditworthiness.

Quantitative analysis using financial models, such as the Financial Impacts of Distributed Energy Resources (FINDER) model at Lawrence Berkeley National Laboratory, can provide a better understanding of the financial implications of different customer and utility options. In fact, Arizona, Kansas, Massachusetts, and New Mexico have already used financial models to examine the impact of aggressive energy efficiency and distributed energy resource penetration goals on utilities and customers.[171,172, 173, 174] Increased analysis of the financial effects of regulatory actions ranging from doing nothing to the adoption of various mitigation measures will inform the deliberative process and, ideally, help forge compromise among conflicting objectives.

7.3.7 Encouraging Innovation

The declining cost of service experienced from the dawn of electric utilities through the 1970s was primarily due to utility innovation. This track record of innovation was largely derailed by nuclear power cost overruns in the late 1970s and 1980s. External forces supplanted the utilities as innovators, while relying on the utilities to provide pricing mechanisms that supported that innovation.

There has been concern about how utilities can remain innovative since the beginning of the industry. Samuel Insull was concerned about:

> …the extent to which such a scheme of regulation is destructive of the initiative of enterprise and the initiative of the inventor. … I thought that was one of the most serious menaces; that if our business was going to run too much by rule … it might be possible that the initiative of the enterprise and enthusiasm of the operator and the risk that the commercial man might be unfavorably affected by commission rule, and that it was one of the things the commissions and the utility men would have to guard against.[175]

Innovation is not always accompanied by a viable business model. *Fortune* magazine named Enron Corporation the "most innovative company in America" six years in a row (1996–2001), including the year that the company declared bankruptcy after committing market manipulation and fraud.

The challenge of the new distribution utility business model is to harvest innovation that benefits customers while providing entrepreneurs adequate reward for inventiveness and supporting widespread deployment. As discussed, utilities have often provided the financial support for innovation. They have tremendous access to capital and billing systems that could be leveraged to finance innovation. It is vital to evaluate how innovation fits into the scope of the business model.

With just one electric investor-owned utility— Green Mountain Power (GMP),[ss]—the State of Vermont, seems to have found the intersection of regulation and innovation. The achievement demonstrates the benefit of a forward-looking cooperative relationship between the regulator (PSB) and the utility. A central feature of the Vermont alternative regulatory plan is the role of IRP. As described by GMP:

[ss] GMP can be characterized as a smart integrator, as the State restructured its electric utilities in the 1990s, with purchase power expenses largely dependent upon those in Independent System Operator New England.

> First, we discuss how GMP plans to combine its vision to become an integrated energy service company with specific strategies and prospective investments that will meet our customers' need for energy services at low cost. Second, we outline a power supply strategy that realizes Vermont's energy policy goals while managing cost volatility and regional rate competitiveness.[176]

What is unique about GMP's IRP is that it explicitly discusses the utility's role as a force of innovation. The Vermont PSB has enabled innovation at GMP by expanding the scope of traditional utility activities, including the following:

- Leasing energy-efficient heat pumps to customers
- Developing the State's EV infrastructure
- Providing home energy renovations and upgrades, including home energy controls, through its "ehome initiative," including low interest on-bill financing for up to $15,000 over 10 years
- Collaborating with Tesla and NRG to provide on-site storage and DER-enhancing resilience during extreme weather events
- Increasing the incorporation of distributed renewable power.

In this process, the Vermont PSB has also designed rates that allow the utility to recover costs while moving closer to time-varying rates that reflect bulk energy market prices. Rates are determined for a three-year period, with quarterly adjustments of power costs, annual adjustments to reflect changes in operating costs, and an annual earnings reconciliation.[177] A longer rate cycle enables company management to focus on pursuing the plan to provide service, as opposed to managing rate requests.

A process that encourages both the utility and the market to provide innovative solutions for providing customer service is needed. Vermont provides an example of a utility working with an innovator. Such a model seems to provide a successful approach to innovation collaboration. Other models are also possible, and the planning process provides a venue to explore impediments to their implementation.

7.4 Resolving Jurisdictional Ambiguity

Jurisdictional ambiguity creates regulatory uncertainty and risk to the future evolution of the distribution utility business model. The net effect impedes progress in the development of the clean-energy economy. A number of mechanisms can resolve this uncertainty through a more cooperative approach to regulation between the State PUCs and Federal Energy Regulatory Commission (FERC).

Attempts to harmonize Federal and State regulation are not new. Almost a century ago, Frankfurter and Landis proposed a solution to what they saw as growing conflicts between States and the Federal Government over the regulation of the development of power:

> The regional characteristic of electric power, as a social and economic fact, must find a counterpart in the effort of law to deal with it. No single State in isolation can wholly deal with the problem. The facts equally exclude the capacity of the Federal Government to cover the field. Co-ordinated regulation among groups of states, in harmony with the Federal Administration over developments on navigable streams and in the public domain, must be the objective. Regional solutions in such new and

> complicated demands upon law must necessarily be empiric and cautious in their unfolding. The exact form of future legal devices will have to be modified from time to time, and from region to region, adapted to varying conditions and, it is to be hoped, built on a growing body of experience. The vehicle for this process of legal adjustment is at hand in the fruitful possibilities inherent in the Compact Clause of the Constitution.[178]

The early use of compacts in the power industry was designed to resolve interstate resource allocations, as in the Colorado River Compact, which provides for the "equitable division and apportionment of the use of the waters of the Colorado River system" and "[establishes] the relative importance of different beneficial uses."[179] More recently, compacts have been used to plan and evaluate methods of providing service to customers. For example, the *Northwest Power Act of 1980* created the Northwest Power and Conservation Council, a compact between Idaho, Montana, Oregon, and Washington, which is directed to prepare a power plan to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply.[180]

Section 209(a) of the *Federal Power Act of 1935* contains provisions to facilitate State regulation by authorizing the Federal Power Commission to establish a joint board to deal with any matter arising in the regulation of companies engaged in interstate commerce. The Commission has acted in cooperation with the States to enable them to regulate areas where they might not have well-established jurisdiction. In Vermont, a joint board was established that enabled the State to regulate an intrastate merger. This joint board was formed because Vermont had not established jurisdiction to regulate mergers.[181] Since that time, most states have established the jurisdiction to regulate mergers, thereby avoiding the need for joint boards for that purpose. Section 209(b) of the *Federal Power Act of 1935* also empowers FERC to confer and to hold joint hearings with states with regard to the relationship between rate structures, costs, and the regulations of State Commissions.

While a host of mechanisms has already been used to harmonize State and Federal jurisdiction, new mechanisms can be crafted. One such mechanism, using the Commerce Clause, could on application by the States, establish…

> …a multi-state Federal Regulatory Agency consisting of members appointed by the President from the FERC and the states involved. The Federal Agency would exercise plenary utility-regulatory authority, displacing both Federal and State regulation.[182]

Resolving jurisdictional ambiguity will not be simple. The starting point is increased State/Federal cooperation and the beginning of a robust dialog on how the diverse set of interests of each jurisdiction and its stakeholders can be accommodated. Each of these mechanisms requires not only buy-in from the various levels of government, but often Federal and State legislative approval. To be successful, a credible form of governance must be established. Reducing the uncertainty associated with regulatory oversight will create a more stable investment environment, facilitating the development of the clean-energy economy at the lowest possible cost.

7.5 Getting There

It bears repeating that the electric distribution utility is at a strategic inflection point. The utility industry plays a vital role in America's economy. The industry's health is essential to the well-being of the U.S. population. Electricity is not an isolated commodity; it affects all aspects of our Nation's social and economic fabric. The manner by which electricity is provided to millions of consumers influences many markets, and what goes on in other markets significantly affects the provision of electricity.

There is no single right way for the electric distribution business model to evolve; it must reflect local markets, customer needs, resource availability, and policy circumstances. Adaptive structures are required to accommodate technologies and requirements currently unforeseen that will no doubt develop in the future.

The process of developing the distribution utility business model of the future is a balancing act. Establishing guiding principles and articulating their relative importance, along with a clear decision framework, enables those engaged in the process to map out a path forward.

Only a collaborative process can create a sustainable result. The industry faces many challenges that effective collaboration can transform into opportunities for customers, utilities, and market-based firms.

Underlying this collaborative process are two key issues that will determine the future of distribution utilities: (1) the scope of utility activities, and (2) the manner by which rates that allow cost recovery and provide desired incentives to both to customers and utilities are crafted. Thus, the planning process provides a useful forum for addressing both issues.

The scope of utility activities now and in the future is a matter that regulators, utilities, and all stakeholders need to address. It is not prudent to restrict consideration of options that can provide least-cost solutions for electric customers.

The manner in which rates are crafted to allow cost recovery is vitally important. Cost is a critical element and plays a substantial role in designing rates. Unfortunately, it has been more than 40 years since there has been a comprehensive, nationwide study of the design of utility rates. Information about rate design and the underlying cost-of-service studies has become fragmented, partially since regulation has increasingly relied on multi-year rate settlements in which the details of costs and rates are reviewed less frequently and as a consequence are slower to pick-up changes in costs. (although this practice can also have benefits for utilities, as in the case of Green Mountain Power). New methods of conducted cost studies need to be developed that use practices and protocols that reflect current technology and market conditions. To facilitate the discussion and understanding of the costs involved for stakeholders and decision-makers (in State PUCs), a new, nationwide study of the design of utility rates must be advanced.

The path to the future is going to be very interesting and far from simple. It is essential that we move forward in a way that preserves the best of what exists while embracing new players, advancements, and opportunities. The path is filled with many analytically and politically difficult issues that should be translated and understood by all involved, as the destination has great implications for our quality of life and the strength of our national economy. Access to an analytical framework that supports the dialogue by facilitating and encouraging the greatest participation of stakeholders is imperative.

There is no doubt that the electric distribution utility will continue to play a vital role in powering the American economy. It must take on new roles to meet emergent challenges and opportunities. The utility of the future will no longer be a monopoly provider, but will increasingly serve as a platform to support many competitive service opportunities. Meeting the challenge of this transformation requires that many diverse interests work together to address and create a business model of the future that will benefit all as it moves the Nation toward a cleaner, low-cost, reliable, and resilient energy future.

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