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Electricity Regulation In the US: A Guide

SECOND EDITION

Author

Jim Lazar, with RAP staff



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June 2016

Foreword to the Second Edition

The original 2011 edition of *Electricity Regulation in the US: A Guide* has proven to be a handy reference for many people in the field. It was designed to be an introduction for the newly appointed regulatory commissioner, the first-time rate case participant, or the newly hired regulatory analyst. We think it has served that function well.

This revised edition includes updates to every chapter, and a number of new chapters. The new chapters include Integrated Distribution System Planning and Renewable Energy, plus a greatly expanded chapter on Regulatory Treatment of Environmental Compliance Costs.

The balance between completeness and brevity is a difficult challenge. We want this handbook to be short enough that it is not intimidating, current enough to be relevant, and complete enough to provide initial guidance on almost any regulatory topic. It is no substitute for Charles Phillips' *The Regulation of Public Utilities*, or Bonbright's seminal *Principles of Public Utility Rates*. Each chapter refers the reader to other resources that cover that topic in greater detail. Many of these are RAP publications, and we encourage all readers to visit www.raponline.org and peruse our library of publications, presentations, and webinars.

Dozens of readers of the first edition contributed ideas that led to this update. The regulatory world is not static, and things will continue to change. Don't hesitate to contact us with things you think need to be added, things that are inadequately explained, or areas where you think we don't quite get it right.

This update has been a project involving most of RAP's team, but it builds strongly on the effort for the first edition. Our inside team included Jim Lazar, an economist with 38 years of experience in utility regulation, as lead author, plus Carl Linvill, Rich Sedano, John Shenot, David Littell, David Farnsworth, and Ken Colburn as authors of the new material. The internal review team included Rick Weston, Riley Allen, Donna Brutkoski, and Becky Wigg. Our outside review team includes former Commissioners Jeff Goltz (Washington State), Ron Binz (Colorado), Bob Lieberman (Illinois), Tim Woolf (Massachusetts), and Karl Rabago (Pace University). We cannot forget the work on the first edition of Edith Bayer, Christopher James, Thad Curtz, Wayne Shirley, and Diane Derby.

All of this was under the careful watch of Rich Sedano, US Team Leader, and Camille Kadoch, RAP Publications Manager.

Jim Lazar
Olympia, Washington June, 2016

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Acronyms

| | |
|----------------|---|
| AC | Alternating Current |
| AFUDC | Allowance for Funds Used During Construction |
| AMI | Advanced Metering Infrastructure |
| APPA | American Public Power Association |
| BPA | Bonneville Power Administration |
| CAA | Clean Air Act |
| CAPM | Capital Asset Pricing Model |
| CCR | Coal Combustion Residuals |
| COU | Consumer-Owned Utility |
| CPCN | Certificate of Public Convenience and Necessity |
| CPP | Clean Power Plan |
| CSAPR | Cross-State Air Pollution Rule |
| CVR | Conservation Voltage Regulation |
| CWA | Clean Water Act |
| CWIP | Construction Work in Progress |
| DC | Direct Current |
| DCF | Discounted Cash Flow |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DRP | Distribution Resource Planning |
| EERS | Energy Efficiency Resources Standards |
| EFSEC | Energy Facilities Site Evaluation Council |
| EGU | Electricity Generating Unit |
| EIM | Energy Imbalance Market |
| EIS | Environmental Impact Statement |
| EPA | (US) Environmental Protection Agency |
| ERCOT | Electric Reliability Council of Texas |
| EU-ETS | European Union Emission Trading System |
| EV | Electric Vehicle |
| FAC | Fuel Adjustment Clause |
| FACT | Flexible AC Transmission System |
| FERC | Federal Energy Regulatory Commission |
| G&T | Generation & Transmission Cooperative |
| IDP | Integrated Distribution Planning |
| IOU | Investor-Owned Utility |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Planning |
| ISO | Independent System Operator |
| kV | Kilovolts |
| kWh | Kilowatt-Hour |
| LEED | Leadership in Energy and Environmental Design |
| LIHEAP | Low Income Home Energy Assistance Program |
| LIRP | Localized Integrated Resource Planning |
| LPPC | Large Public Power Council |

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| MATS | Mercury and Air Toxics Standards |
| MWh | Megawatt-Hour |
| NAAQS | National Ambient Air Quality Standards |
| NASEO | National Association of State Energy Officials |
| NASUCA | National Association of State Utility Consumer Advocates |
| NEB | Non-Energy Benefit |
| NEM | Net Energy Metering |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Council |
| NO_x | Nitrogen Oxides |
| NRECA | National Rural Electric Cooperative Association |
| NUG | Non-Utility Generator |
| OASIS | Open Access Same-Time Information System |
| OATT | Open Access Transmission Tariff |
| OPI | Other Program Impacts |
| PACT | Program Administrator Cost Test |
| PBR | Performance-Based Regulation |
| PCT | Participant Test |
| PGA | Purchased Gas Adjustment |
| PIPP | Percentage of Income Payment (Programs) |
| PMA | Power Marketing Agency |
| PPA | Power Purchase Agreement |
| PUC | Public Utility Commission |
| PURPA | Public Utility Regulatory Policies Act |
| PV | Photovoltaic |
| RCRA | Resource Conservation and Recovery Act |
| REC | Renewable Energy Certificate |
| REV | Reforming the Energy Vision |
| REZ | Renewable Energy Zone |
| RGGI | Regional Greenhouse Gas Initiative |
| RIIO | Revenue = Incentives + Innovation + Outputs (British) |
| RIM | Ratepayer Impact Measure (Test) |
| RPC | Revenue Per Customer |
| RPS | Renewable Portfolio Standard |
| RTO | Regional Transmission Organization |
| SBC | System Benefit Charge |
| SCADA | Supervisory Control and Data Acquisition |
| SCR | Selective Catalytic Reduction |
| SEP | State Energy Program |
| SFV | Straight Fixed/Variable (Pricing) |
| SNCR | Selective Non-Catalytic Reduction |
| SO₂ | Sulfur Dioxide |
| SQI | Service Quality Indices |
| TOU | Time-Of-Use |
| TRC | Total Resource Cost (Test) |
| TVA | Tennessee Valley Authority |

| | |
|-------------|----------------------------|
| UC | Utility Cost (Test) |
| VER | Variable Energy Resource |
| VOC | Volatile Organic Compound |
| VOST | Value of Solar Tariff |
| WCI | Western Climate Initiative |

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About This Guide to Utility Regulation

Over the past 150 years, society has undergone a fundamental transformation. The invention of the incandescent light bulb in the 1870s introduced lighting as one of the first practically available uses of electrical power. Electric utilities began to spring up in major cities during the 1880s, and by the 1900s they had spread across the United States. While investor-owned utilities served urban areas and industrial customers prior to World War I, a drive for universal service was launched in the 1930s, with the creation of the Rural Electrification Administration, now the Rural Utilities Service in the US Department of Agriculture. The National Academy of Engineering designated electrification as the 20th century's greatest engineering achievement, beating the automobile, computers, and spacecraft.

This conclusion is hardly surprising when one considers the intricate web of wires that connects every light switch in the United States to massive power plants, individual rooftop solar panels, and every source of electricity **generation** in between. Add to this the layer of pipes that runs underground to feed stovetops, power stations, and factories with natural gas, and you have the foundation on which modern society has been built.

The utility grid of interconnected electric and natural gas infrastructure continues to grow as the US population expands and demand for energy increases. In 2014, US consumption of energy (electricity and all fuels including natural gas) to power industry, residential homes, commercial establishments, and all transportation was 98 quadrillion BTUs.

Although the transportation sector has been served by competitive providers since the 1920s, electricity and natural gas service was deemed to be a natural monopoly because of economies of scale and the significant capital necessary to build power plants, transmission lines, and natural gas pipes and plants. Electricity and natural gas companies developed what we now recognize as monopolies offering electricity and natural gas service from a single provider on largely unnegotiable terms as discussed subsequently. To address the disparity in economic leverage between the customer and the monopoly provider, regulation of the utility system has evolved over the past 150 years to ensure that the system is reliable, safe, and fairly priced.

This guide focuses on electric and, to a much lesser extent, gas utility regulation in the United States, and is meant to provide a basic understanding of the procedures used and the issues involved. Many of the concepts and methods discussed are also applicable to other regulated industries and to self-regulated, consumer-owned electric utilities.

The purpose of this guide is to provide a broad perspective on the universe of utility regulation. The intended audience includes anyone involved in the regulatory process, from regulators to industry to advocates and consumers. The following pages first address why utilities are regulated, and then provide an overview of the actors, procedures, and issues involved in regulation of the electricity and gas sectors. The guide is intended to serve as a primer for new entrants and assumes that the reader has no background in the regulatory arena. It also provides a birds-eye view of the regulatory landscape, including current developments, and can therefore serve as a review tool and point of reference for those who are more experienced.

Utility regulation is also a political endeavor, however. Regulators are either appointed by elected officials, or they are directly elected to office. Their job is not only to administer the law in a fair, just, and reasonable fashion, but also to facilitate the achievement of the purposes of those laws. This guide does not attempt to address the political side of regulation. Every state and region has local circumstances, local political goals, and expects distinct results from its regulators. In every state, the laws under which regulators operate are different. And the goals set by voters change—sometimes rapidly—over time. It would not be useful to draft a single guide to the political aspects of regulation, and it would be inappropriate for the Regulatory Assistance Project, a non-profit educational organization, to attempt to do so. The politics may be at least as important as the framework we address in this guide. The reader will need to seek other sources for guidance on the politics of regulation.

These chapters briefly touch on most topics that affect utility regulation but do not go into depth on each topic, as we have tried to keep the discussion short and understandable. For more in-depth analysis of particular topics, please refer to the list of reference materials at the end of each chapter. The Regulatory Assistance Project publishes detailed reports on particular topics that provide a more comprehensive review of many topics in this guide, which are available online at www.raonline.org. Also, a lengthy glossary appears at the end of this guide to explain utility-sector terms.

1. The Purpose of Utility Regulation

Electric (and natural gas) utilities that deliver retail service to consumers are regulated by state, federal, and local agencies. These agencies govern the prices utilities charge, the terms of their service to consumers, their budgets and construction plans, and their programs for **energy efficiency** and other services. Utility impacts on air, water, land use, and waste product disposal are typically regulated by other government agencies. Environmental and land use regulation is generally beyond the scope of this guide, except with respect to a discussion of federal regulation of air pollution emissions, water discharges, and waste disposal from power plants in Chapter 20.

Two broad, fundamental principles justify governmental oversight of the utility sector. First, because a utility provides *essential services* for the well-being of society—both individuals and businesses—it is an industry “affected with the public interest.”¹ The technological and economic features of the industry are also such that a single provider is often able to serve the overall **demand** at a lower total cost than any combination of smaller entities could. Competition cannot thrive under these conditions; eventually, all firms but one will exit the market or fail. The entities that survive are called *natural monopolies*, and, like other monopolies, they have the power to restrict output and set prices at levels higher than are economically justified. Given these two conditions, economic regulation is the explicit public or governmental intervention into a market that is necessary to achieve public benefits that the market fails to achieve on its own. In recent years, the power supply element of the electric utility industry has been subject to greater competitive pressures, and in some states (and countries) has been excluded from economic regulation (but not from environmental regulation).

This chapter covers the overall context in which utility regulation operates, as a preface to discussing the structure of the current industry and the regulatory framework that has evolved with it.

1 The term “affected with a public interest” originated in England around 1670, in the treatises *De Portibus Maris* and *De Jure Maris*, by Sir Matthew Hale, Lord Chief Justice of the King’s Bench.

1.1. Utilities are “Natural Monopolies”

In 1848, John Stewart Mill published an analysis of natural monopolies, noting that, “(a) Gas and water service in London could be supplied at lower cost if the duplication of facilities by competitive firms were avoided; and that (b) in such circumstances, competition was unstable and inevitably was replaced by monopoly.”² The arc of policy in the United States has generally been toward introducing competition where it is the most efficient model for allocating resources and meeting essential needs. The natural monopoly concept still applies to at least the network components of utility service (that is, to their fixed transport and delivery facilities). However, even where there is sufficient competition among the providers of energy supply and/or retail billing service, the utility sector’s critical role in the infrastructure of modern, technological society justifies its careful oversight.

1.2. The Public Interest is Important

Regulation is intended to protect the “public interest,” which comprises a variety of elements. Utilities are expected to offer (and in the United States, provide) service to anyone who requests it and can pay for it at the regulator’s (or government’s) approved prices. In this sense, service is “universal.”

A **connection charge** may be imposed if providing service involves a significant expenditure by the utility, but even that is subject to regulation and, in many cases, is subsidized in some manner by other customers or taxpayers.³ Although some public services, like fire and police protection, are provided by government without many direct charges to users, utilities (even when government-owned) are almost always operated as self-supporting enterprises, with regulations dictating the terms of service and prices.

Utilities must also adhere to strict government safety standards, because their infrastructure runs throughout our communities and the public can be adversely affected by sagging wires, ruptured pipes, and other problems.

2 John Stewart Mill, cited in Garfield, P., & Lovejoy, W. (1964). *Public Utility Economics* (p. 15). Englewood Cliffs, NJ: Prentice Hall.

3 Strictly speaking, a subsidy exists when a good or service is provided at a price that is below its long-run marginal cost—that is, the value of the resources required to produce any more of it. Although some market theorists argue for pricing based on short-run marginal cost, that issue here is, in our view, an accident of history. In general, equilibrium—in which the market is operating as efficiently as it can and total costs are minimized—long-run and short-run marginal costs are the same, because the cost of generating one more unit from an existing power plant is the same as the cost of building and operating a new, more efficient power plant. Certainly, the long run—that period of time in which all factors of production (capital and labor) are variable—is the sensible context in which to consider the public-policy consequences of utility matters, because investments in utility infrastructure are, for the most part, extremely long-lived.

The production and **distribution** of electricity and natural gas also have environmental and public health impacts—from the emission of pollutants, through the use of public waters, on scenic views and land uses, and even from noise—that can adversely affect the public. Generating power often produces pollution; transmission and distribution lines have both visual and physical impacts on land use and ecological systems. By the same token, the availability of electricity and natural gas creates opportunities to use less-polluting fuels than oil or coal.

So, depending on the scope of authority delegated to them, regulators may therefore impose environmental responsibilities on utilities to protect these public interests. Regulators are granted specific powers by legislators, and this authority varies from state to state.

Because most utility consumers cannot “shop around” for utility distribution service among multiple providers as a result of the natural utility monopoly, regulation serves the function of ensuring that service is adequate, that companies are responsive to consumer needs, and that transactions like new service orders and billing questions are handled responsively. In addition, the utility is often a conduit—through the billing envelope or other communications—for information that regulators consider essential for consumers to receive.⁴

Finally, given utilities’ crucial role in the economy and in society’s general welfare, service reliability standards are often imposed as well.

1.3. Regulation Replaces Competition as the Determinant of Prices

For most businesses, the prices of goods or services that are sold are determined by what the customer or market will bear. In economic terms, markets will “clear” at the point where **marginal costs** equal the value that consumers, in the aggregate, set for the good or service; that is at the point where supply intersects with demand.

A different approach to price-setting is required for utilities, because competition and free entry into (and exit from) markets does not exist in natural monopolies, and some level of reserve **capacity** is necessary to assure reliable service. Regulators use a *cost of service approach* to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial, and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs, and allocated based on the sales made to each class.

4 In Chapter 3, we discuss the movement in many states toward restructuring or deregulation of the power supply function.

1.4. Regulatory Compact

Effectively, regulation constitutes an agreement between a utility and the government: the utility accepts an obligation to serve in return for the government's promise to approve and allow rates that will compensate the utility fully for the costs it incurs to meet that obligation. This implied agreement is sometimes called the *regulatory compact*.⁵

Despite the above phrasing, there is in fact no binding agreement between a utility and the government that protects utility ownership from financial accountability.⁶ There are numerous examples of regulated utilities going through bankruptcy reorganization because the revenues found prudent and allowed by regulators were insufficient to cover the obligations entered into by utility management. Regulation is an exercise of the police power of the state, over an industry that is “affected with the public interest,” whether that industry enjoys the right to operate as a monopoly provider or not.

The need for regulation of utilities arises primarily from the monopoly characteristics of the industry. The general objective of regulation is to ensure the provision of safe, adequate, and reliable service at prices (or revenues) that are sufficient, but no more than sufficient, to compensate the regulated firm for the costs (including returns on investment) that it incurs to fulfill its obligation to serve. The legal obligations of regulators and utilities have evolved through a long series of court decisions, several of which are discussed in this guide.⁷

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- 5 This is entirely separate from the legal process for defining service territory boundaries. Some states provide for exclusive franchises, approved by the state, whereas others prohibit exclusive franchises. Others leave the franchising role to local government, where it may be as narrow as defining the relationship between the municipality as a regulator of construction activity and permitting the utility to have its facilities in (above and below) city streets and rights of way.
 - 6 This is true in the United States. In other parts of the world, however, regulation by contract is quite common.
 - 7 US Supreme Court case law on the topic begins with its 1877 decision in *Munn v. Illinois*, 94 U.S. 113 (which itself refers to settled English law of the 17th century—“when a business is ‘affected with the public interest, it ceases to become *juris privati* only.”), and runs at least through *Duquesne Light v. Barasch*, 488 US 299 (1989). Nowhere in that series of cases, including *Smyth v. Ames*, 169 U.S. 466 (1898), *FPC v. Hope Natural Gas*, 320 U.S. 591 (1944), and *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968), does the Supreme Court accept the notion of a regulatory compact.

1.5. All Regulation is Incentive Regulation

Some analysts use the term *incentive regulation* to describe a system in which the regulator rewards utilities for taking actions to achieve, or actually achieving, explicit public policy goals. However, it is critical to understand that *all regulation is incentive regulation*. By this we mean that every regulation imposed by government creates limitations on what the utility can do; but every regulation also gives the utility incentives to act in ways (driven generally by the desire to maximize net income, or earnings) that may or may not promote the public interest. Given any set of regulations, utilities will take those actions that most benefit *their* principal constituencies—shareholders and management—while meeting the requirements of the regulations.

For more information:

Lazar, J. (1982). *The People's Power Guide: A Manual of Electric Utility Policies for Consumer Activists*. Olympia, WA: People's Organization for Washington Energy Resources. Retrieved from <http://www.raponline.org/document/download/id/808>

NW Energy Coalition. (1993). *Plugging People Into Power: An Energy Participation Handbook*. Retrieved from <http://www.raponline.org/document/download/id/810>

Steinhurst, W. (2011). *The Electric Industry at a Glance*. Silver Spring, MD: National Regulatory Research Institute. Retrieved from <http://www.synapse-energy.com/project/electric-industry-glance-2011>

US Department of Energy. (2002). *A Primer on Electric Utilities, Deregulation, and Restructuring of US Electricity Markets*. Richland, WA: Pacific Northwest National Laboratory for US DOE. Retrieved from http://www.pnl.gov/main/publications/external/technical_reports/PNNL-13906.pdf

2. A Brief History of Regulation

Utility regulation has evolved from historical policies regulating entities that are “affected with the public interest” into a complex system of economic regulation. One of the earliest forms of business regulation was the requirement in Roman and medieval times that innkeepers accept any person who came to their door seeking a room. Customers could be rejected only if they were unruly or difficult.⁸

This chapter presents a very brief history of utility regulation, setting the stage for a discussion of the traditional regulation now practiced in most of the United States, and certain alternatives that are practiced in some states.

2.1. Grain Terminals and Warehouses, and Transportation

In the 19th century, a series of court decisions in the United States held that grain elevators, warehouses, and canals were “monopoly” providers of service “affected with the public interest”⁹ and that their rates and terms of service could therefore be regulated.¹⁰ When railroads emerged in the second half of the 19th century, regulation in the United States became more formalized with the creation of state railroad commissions, and then the Federal Railroad Commission (which later became the Interstate Commerce Commission¹¹) to regulate rail transportation, and

Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use and must submit to be controlled by the public for the common good ...

— US Supreme Court,
Munn v. Illinois,
94 US 113, 126 (1877)

8 Phillips, C. F. (1984). *Regulation of Public Utilities: Theory and Practice* [3rd ed.] (pp. 75-78). Reston, VA: Public Utilities Reports.

9 The term “affected with a public interest” originated in England around 1670, in the treatises *De Portibus Maris* and *De Jure Maris*, by Sir Matthew Hale, Lord Chief Justice of the King’s Bench.

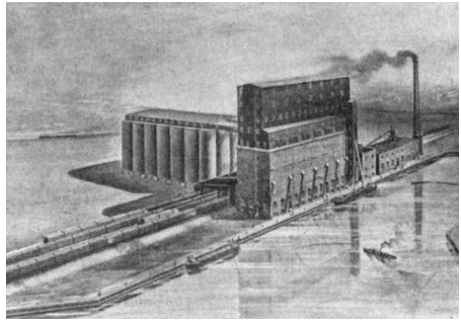
10 *Munn v. Illinois*, 94 U.S. 113 (1877).

11 The Interstate Commerce Commission has since been dissolved following a Congressional determination that truck freight presented a competitive alternative to rail freight, and that neither required economic regulation.

later, trucking. Today, state and federal economic regulation of transportation has mostly ended, as it is perceived that competition exists in most aspects of transportation.

2.2. Utility Regulation

Initially, electric and gas utilities competed with traditional fuels (e.g., peat, coal, and biomass, which were locally and competitively supplied), and were allowed to operate without regulation. If they could attract business, at whatever prices they charged, they were allowed to do so. Cities did impose “franchise” terms on them, charging fees and establishing rules allowing them to run their wires and pipes over and under city streets. Around 1900, roughly 20 years after Thomas Edison established the first centralized electric utility in New York, the first state regulation of electric utilities emerged.¹² The cost-of-service principles of regulation (discussed in detail in Chapters 3 through 8 of this guide) have evolved over the 20th century from this beginning.

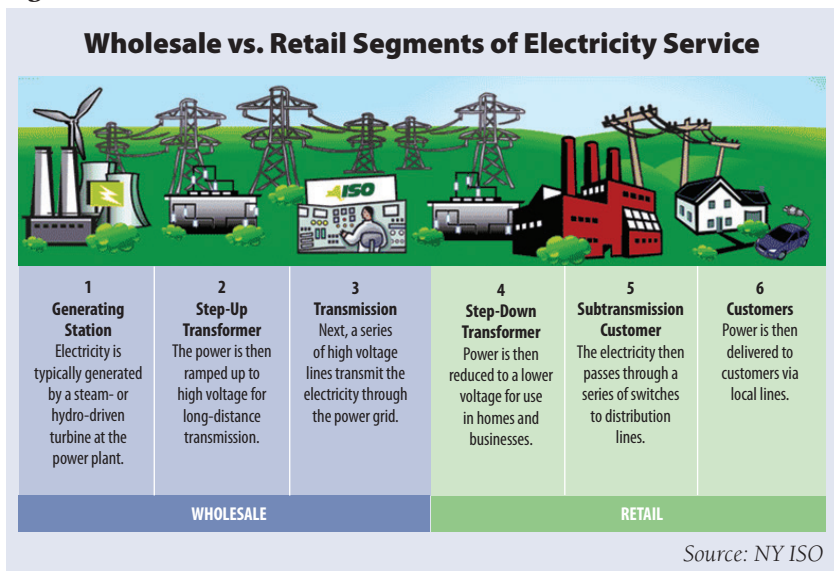


2.3. Restructuring and Deregulation

In about 1980, electricity prices began to rise sharply as inflation became significant, fuel prices soared, and the cost of new power plants with pollution and safety equipment rose sharply. Following developments in the structure of the telecommunications and natural gas industries, large industrial-power users began demanding the right to become wholesale purchasers of electricity. This led, a decade or so later, to the period of restructuring discussed in Chapter 3, during which some states “unbundled” the electricity-supply function from distribution, on the theory that only the wires (the fixed network system) constituted a natural monopoly, whereas the generation of power did not. In some cases, large-volume customers (big commercial and industrial users) were allowed to negotiate directly with

12 Photographs of lower Manhattan at the turn of the 20th century vividly display the economically and aesthetically (if not environmentally) destructive consequences of the over-building of the first duplicative and unnecessarily costly networks of wires that competitive individual firms were constrained to deploy during this period. Ultimately (and, as it turned out, quite quickly), the natural-monopoly characteristics of the industry doomed the less efficient providers to bankruptcy or acquisition by a single firm. (In New York, this company, founded by Thomas Edison, eventually became the aptly named Consolidated Edison.)

Figure 2-1



wholesale power suppliers that competed with the services provided by the utility at regulated prices. In other states, the utilities were forced to divest their power-plant ownership, and the production of power was left to a new industry of competitive suppliers. In both cases, the utilities retained the regulated natural monopoly of distribution.

In the years since 2010, the availability of electricity generation from onsite facilities (primarily from solar and fuel cell units) at prices competitive with the retail price of electricity has forced some regulators to confront the notion of whether an electric utility remains a natural monopoly in light of technological change.

For more information:

Bonbright, J. C. (1961). *Principles of Public Utility Rates* [1st ed.]. New York: Columbia University Press. Retrieved from <http://www.raponline.org/document/download/id/813>

Garfield & Lovejoy, *Public Utility Economics*.

Phillips, *Regulation of Public Utilities: Theory and Practice*.

3. Industry Structure

The electric utility sector is economically immense and vast in geographic scope, and it combines ownership, management, and regulation in complex ways to achieve reliable electric service. This chapter discusses the industry's organization and governance: its forms of ownership, the jurisdiction of federal and state regulators, and how utilities across the country cooperate and coordinate their activities.

3.1. Overview

The US electric industry comprises over 3,000 public, private, and cooperative utilities, more than 1,000 independent power generators, and over 700,000 homes and businesses with onsite solar generating systems.¹³ There are three regional synchronized power grids, eight electric reliability councils, about 140 control-area operators, and thousands of separate engineering, economic, environmental, and land-use regulatory authorities. We will attempt to make all of these terms meaningful. The US Department of Energy's Energy Information Administration collects, organizes, and maintains vast amounts of information and generates many reports about the utility industry and the energy sector in general.¹⁴

3.1.1. Investor-Owned Utilities

About 75 percent of the US population is served by **investor-owned utilities**, or IOUs. These are private companies, subject to state regulation and financed by a combination of shareholder equity and bondholder debt. Most IOUs are large (in financial terms), and many have multi-fuel (electricity and natural gas) or multistate operations. Quite a few are organized as holding companies with multiple subsidiaries, or have sister companies controlled by a common parent corporation.¹⁵

13 Solar Energy Industries Association (SEIA). *Solar Industry Data*. Retrieved from <http://www.seia.org/research-resources/solar-industry-data>

14 For more information, see: <http://www.eia.gov>

15 The investor-owned utilities are organized through a trade and lobbying group called the Edison Electric Institute (EEI). See: <http://www.eei.org>

3.1.2. Public Power: Municipal Utilities, Utility Districts, and Cooperatives

Consumer-owned utilities (COUs) serve about 25 percent of the US population, including cities and many large rural areas. (In addition, there are a small number of consumer-owned natural gas utilities.) These utilities include:

- **City-owned or municipal utilities**, known as “munis,” which are governed by the local city council or another elected commission;
- **Public utility districts** (of various types) that are utility-only government agencies, governed by a board elected by voters within the service territory;¹⁶
- **Cooperatives (co-ops)**, mostly in rural areas, which are private nonprofit entities governed by a board elected by the customers of the utility.¹⁷ Most co-ops were formed in the years following the Great Depression, to extend electric service to remote areas that IOUs were unwilling to serve; there are also some urban cooperatives;¹⁸ and
- **Others**, including a variety of Native American tribes, irrigation districts, mutual power associations, and other public and quasi-public entities providing electric service in a few parts of the United States.

Figure 3-1

| Utility Consumers, Sales, and Revenues, 2014 | | | | | |
|---|---------------------|--------------------|----------------------|------------------------|----------------|
| Type of Utility | Number of Utilities | Consumers | Sales (MWh) | 2014 Revenue x \$1,000 | Average \$/kWh |
| Investor-Owned | 199 | 86,816,419 | 1,926,805,312 | 207,051,497 | \$0.107 |
| Municipal | 824 | 15,007,065 | 395,141,132 | 39,882,627 | \$0.101 |
| Cooperatives | 855 | 18,942,612 | 428,439,745 | 44,555,361 | \$0.104 |
| Other | 288 | 11,913,427 | 406,820,181 | 36,362,520 | \$0.089 |
| Total | 2,166 | 132,680,523 | 3,157,206,370 | 327,852,005 | \$0.104 |

As reported to US Energy Information Administration

16 The public power districts and municipal utilities are organized through a trade and lobbying group called the American Public Power Association (APPA). See: <http://www.publicpower.org>

17 Although public power districts conduct elections like other governments, with a one-person, one-vote principle, co-op elections are normally limited to the consumers of the utility—typically on a one-meter, one-vote basis, including business consumers and persons ineligible to vote in general government elections.

18 The cooperatives are organized through a trade and lobbying group called the National Rural Electric Cooperative Association (NRECA). See: <http://www.nreca.org>

Increasingly, solar leasing companies are offering power from generating units installed on customer property, and these are included in the “other” category.

Figure 3-1 shows the customers and sales for each category of electricity provider, as reported to the US Energy Information Administration.

3.2. Vertically Integrated Utilities

Vertically integrated utilities are responsible for generation, **transmission**, and distribution of power to retail customers. In many cases, they own some or all of their power plants and transmission lines, but they may also buy power through contracts from others, giving them the operational equivalent of power-plant ownership. Most use a combination of owned resources, contract resources, and short-term purchases and sales to meet their customer demands, and a combination of their own transmission lines and lines owned by others to move power from where it is produced to the communities they serve. The mix of these varies widely from utility to utility.

3.3. Distribution-Only Utilities

Many electric utilities (and most natural gas utilities) are not vertically integrated, and provide only distribution service. By sheer number, the vast majority of distribution-only utilities are smaller and consumer-owned, but some are large investor-owned utilities serving in states that have undergone restructuring. These distribution-only utilities do not own any generating resources. They either buy their power from one or more upstream wholesale providers, or, in the **restructured states**, consumers may obtain their power directly from suppliers, with the utility providing only the distribution service.

3.4. Non-Utility Sellers of Electricity

Many states prohibit the sale of electricity to the public by any business other than a utility. Nonetheless, a number of non-utilities sell electricity to the public in various ways. For example, campgrounds and marinas have “hookups” for transient RVs and boats. They typically buy power at a regulated retail rate, and sell power at a daily, unmetered rate. In most states, this has been either explicitly exempted from regulation or simply tolerated. The same is true for landlords of multi-tenant buildings who may submeter electricity and bill tenants; if they simply divide up the bill of the regulated utility and do not add additional charges, this is generally tolerated. More recently, companies have begun installing solar electric systems and charging customers either a fixed lease payment (not linked to kilowatt-hour [kWh] production) or a per-kWh rate for power provided. In some states this has been controversial, and in a few it has been prohibited. Similarly, providers of

electric vehicle (EV) charging stations provide electricity to the public; some do so at no charge, some at regulated prices, and some at unregulated prices.

3.5. Trends Toward Less-Regulated Systems

The United States, along with most of the European Union, New Zealand, and Australia, is seeing a trend toward a less-regulated power sector. In the United States, this emerged in the 1980s with natural gas utilities initiating “gas transportation service” for their large commercial and industrial customers, and then spread to what was called “retail wheeling” for electricity customers.

In particular, the power supply function is more commonly seen as a competitive sector, and one in which competition, rather than regulation, can produce beneficial results for consumers. This is particularly evident in New England, the mid-Atlantic region, and Texas.

The Public Utility Regulatory Policies Act (1978) (PURPA) required utilities to purchase output from qualifying generators. The Energy Policy Act (1992) created a new regulatory designation, Exempt Wholesale Generators, and made market-based rates available where cost-based rates had been all that was available previously. Congress, through legislative refinements, and the Federal Energy Regulatory Commission (FERC), through rulemakings, have further elaborated on the rules governing competitive wholesale power markets. Many states contributed to the trend by causing or permitting divestment of utility generation. Today nearly half the generation in the United States is owned by non-utilities, although much of the non-utility generation is under long-term contract to utilities.

Some regulators are experimenting with significant changes to the regulation of distribution utilities as well. These include redefining the role of the distribution owner from “utility” providing service to “distribution platform provider,” supplying a network in which customers, vendors, and aggregators of services can all play a role in the provision of reliable service. A common thread across all utility forms in the United States is a commitment to connect customers at reasonable terms and conditions.

3.6. Federal vs. State Jurisdiction

Some aspects of the industry, such as interstate transmission and wholesale power sales, are federally regulated; some, such as retail rates and distribution service, are state-regulated; and some, such as facility siting and environmental impacts, may be regulated locally. Some functions, such as customer billing, are treated as monopoly services in many jurisdictions, but are treated as competitive in others.

The FERC handles most of the federal regulation of the energy sector, but some activities are regulated by the Environmental Protection Agency (EPA),

federal land agencies (such as the Bureau of Land Management), or other federal bodies.

In most cases, the US Constitution allows federal intrusion into private economic activity only where interstate commerce is involved. Interstate transmission of electricity and natural gas clearly meets this test, and the courts have concluded that other parts of the electricity and natural gas supply system that affect interstate commerce, notably wholesale energy transactions, are also subject to federal regulation, federal guidance, and/or federal oversight.

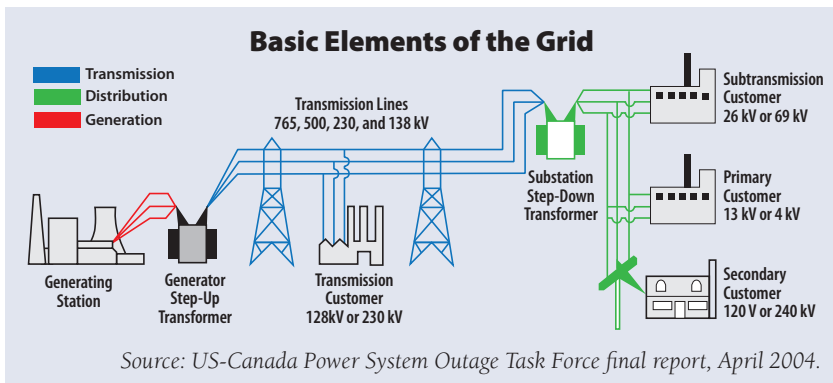
State regulators adopt construction standards for lower-voltage retail distribution facilities, quality of service standards, and the prices and terms of service for electricity provided by investor-owned utilities. In some states, they also regulate consumer-owned (i.e., cooperative and municipal) utilities, but in most states this is left to local governmental bodies and elected utility boards.

3.7. Power Supply

Figure 3-2 shows the most essential elements of the power grid: generation, transmission, and distribution facilities.

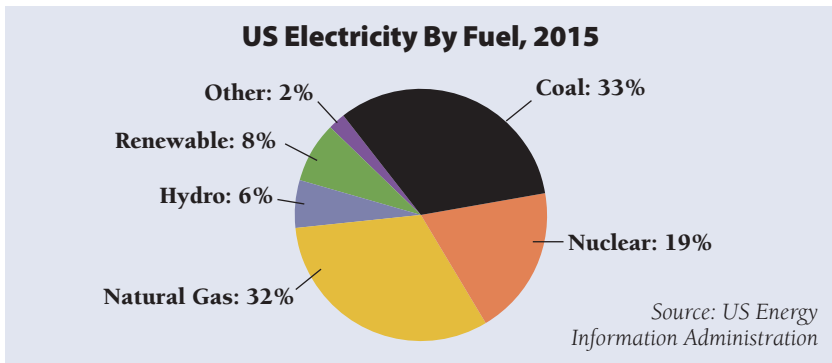
Most electricity in the United States is generated by coal, natural gas, and nuclear power plants, with lesser amounts from hydropower and other **renewable resources** such as wind and solar.¹⁹ Licensing of nuclear and hydropower facilities is federally administered, for the most part, by FERC and the Nuclear Regulatory Commission, whereas licensing and siting of

Figure 3-2



19 Less than one percent of US net electric generation came from oil-fired units in 2011. See: US Energy Information Administration. (2012, September). Table 8.2a: Electricity Net Generation: Total (All Sectors) 1949-2011. Retrieved from <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0802a>

Figure 3-3



other types of power production facilities—about 75 percent of the total—is managed at the state and local levels.

Individual utilities or utility consortia are responsible for most power generation, with some coming from federal agencies and an increasing amount from independent, non-utility suppliers.

3.7.1. Federal Power Marketing Agencies

Federal **power marketing agencies** (PMAs) were created by Congress to market power produced by federal dams. In some cases, they have also been given authority to build and own thermal power plants. These federal PMAs include the Bonneville Power Administration (BPA), the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration. The Tennessee Valley Authority (TVA) is technically not a PMA, but operates in much the same way. Generally, the PMAs only sell power at wholesale to local, vertically integrated utilities or local distribution utilities. However, BPA and TVA also operate extensive transmission grids, serving numerous local distribution utilities.

3.7.2. Regulation of Wholesale Power Suppliers/Marketers/Brokers

FERC has clear authority to regulate wholesale power sales, except when the seller is a public agency. The federal power marketing agencies, such as the TVA and BPA, and local municipal utilities are subject to limited FERC regulation with respect to wholesale power sales and transmission services.

Hundreds of companies are registered with FERC as wholesale power suppliers. Although some own their own power plants, marketers often do not; instead they buy power from multiple suppliers on long-term or spot-market bases, then resell it. Brokers arrange transactions, but never actually take ownership of the electricity.

3.7.3. Non-Utility Generators

A **non-utility generator** (NUG), or **independent power producer** (IPP), owns one or more power plants but does not provide retail service. It may sell its power to utilities, to marketers, or to direct-access consumers through brokers. Sometimes a NUG will use a portion of the power it produces to operate its own facility, such as an oil refinery, and sell the surplus power. Some enter into long-term contracts, while others operate as merchant generators, selling power on a short-term basis into the wholesale market. Some NUGs are owned by parent corporations that also operate utilities; in this situation, the regulator will normally exercise authority over affiliate transactions.

3.7.4. Consumer-Owned Utilities

COUs, including munis, co-ops, and public power districts, are often distribution-only entities. Some procure all of their power from large investor-owned utilities, and some from federal power-marketing agencies.

Groups of small utilities, mostly **rural electric cooperatives** and munis, have formed **generation and transmission cooperatives** (G&Ts) or joint action agencies to jointly own power plants and transmission lines. By banding together, they can own and manage larger, more economical sources of power, and the G&Ts may provide power management services and other services for the utilities. Such G&Ts typically generate or contract for power on behalf of many small-sized member utilities, and often require the distribution cooperatives to purchase all their supply from the G&T.

A significant number of COUs do own some of their own power resources, which they augment with contractual purchases, market purchases, and purchases from G&Ts. A few COUs own all their supply, and sell surplus power to other utilities.²⁰

3.7.5. Joint Power Agencies and G&Ts

Consumer-owned utilities often join together to develop power resources. Public power utilities often use joint power agencies, which are legally separate municipal corporations that sell bonds, build facilities, enter into contracts, and sell the resulting power to the member utilities. Groups of electric cooperatives often form G&Ts to build facilities to serve the needs of the cooperatives in a geographic region.

²⁰ The 24 largest consumer-owned utilities are organized through a trade and lobbying group known as the Large Public Power Council (LPPC). These utilities collectively own about 75,000 megawatts of generation. See: <http://www.lppc.org>

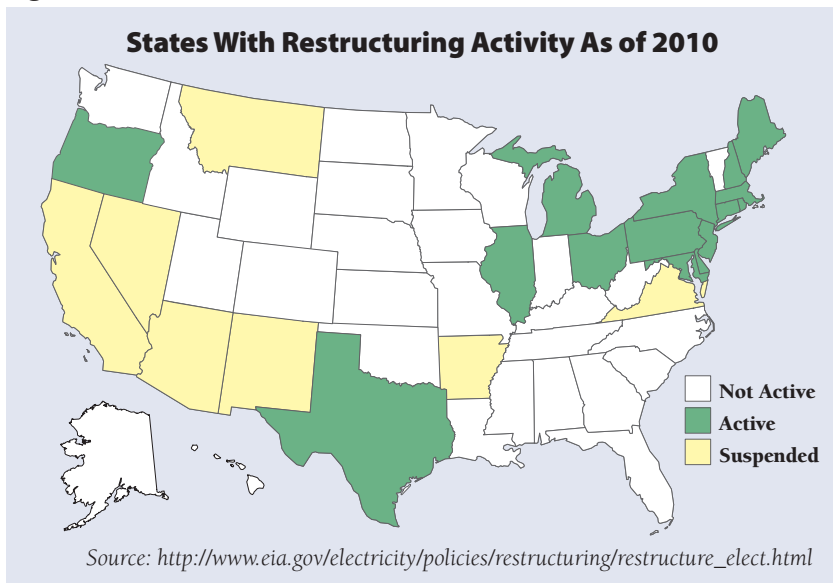
3.7.6. Retail Non-Utility Suppliers of Power

Beginning in about 1990, England and Wales began restructuring their utilities to allow *direct access* by letting customers choose a power supplier competitively and pay the utility only for distribution service. Under restructuring, utilities may provide combined billing for both the distribution service (which they provide) and for the power (which is supplied by others). (The term retail electricity service is widely used overseas to mean the business that actually interacts with the consumer, issuing bills and collecting revenues. In the United States, distribution utilities perform these functions almost exclusively.)

After 1994 the British experiment was followed by some US states, now including California, Illinois, Texas, Ohio, and most of New England. In most cases, investor-owned utilities in these states had previously owned power plants, but sold them to unaffiliated entities or transferred them to non-regulated subsidiaries of the same parent corporation.

Most of these states made provisions for a **default supply**—also referred to as **basic service**—for those consumers who do not choose a competitive supplier, or whom the competitive market simply does not serve. Although a significant percentage of large industrial-power users are direct-access customers, most residential and small-business consumers are served by the default supply option.²¹ Figure 3-4 shows restructuring activity as of 2010;

Figure 3-4



21 America's experience with retail competition in supplying electricity has revealed that the costs of acquiring and administering the accounts of low-volume users generally exceed the profit margins that sales of the power as a commodity, separate from distribution, allow.

both California and Montana have since moved back toward regulated utility service, and some states provide for consumer choice for some (typically large) customers, but not for all customers. In several states, community choice aggregation allows the municipality to serve as a collective form of wholesale power acquisition.

In states that have restructured their retail electric markets, separate companies exist to sell commodity electricity to local individual consumers. Some companies specialize in selling “green” power from renewable energy, whereas others specialize in residential, commercial, or industrial service. These suppliers may own their own power plants, buy from entities that do, or buy from marketers and brokers.

Some states allow large customers to “buy-through” their utility to obtain direct purchases of electric power, even though other customers do not have this option. Sometimes this is done to allow the customers access to lower cost power, and sometimes to allow access to renewable energy that customers prefer to buy. In Chapter 10, we discuss green power programs that allow customers to access renewable energy from their utility, and in Chapter 18 we discuss community solar, a form of shared-ownership of renewable resources.

3.8. Transmission

Power from these various resources is distributed over extra high-voltage AC transmission networks (115,000 volts and greater), linked into three transmission **synchronous interconnections** (sometimes termed “interconnects”) in the continental United States. These are the Eastern Interconnection, covering the region east of the Rockies, excluding most of Texas, but including adjacent Canadian provinces except Québec; the Western Interconnection, from the Rockies to the Pacific Coast, again including adjacent Canadian provinces; and the Electric Reliability Council of Texas (ERCOT), covering most of Texas (see Figure 3-5). These three AC systems operate independently. There are a few DC connections between them that enable limited scheduled power flows across these interfaces. DC lines are also used in a few instances to transmit quantities of power over long distance with low losses, as along the Pacific Coast, or from northern Canada to the northern tier of the United States.

Because 47 states (excluding ERCOT, Hawaii, and Alaska) have interconnected transmission networks, FERC sets the rates and service standards for most bulk power transmission. FERC has been experimenting in recent years with bonus returns for some projects to encourage construction, consistent with its Order 679 from 2011. The industry has also seen an increase in the role of independent transmission-owning companies unaffiliated with electric distribution companies. FERC has been granted

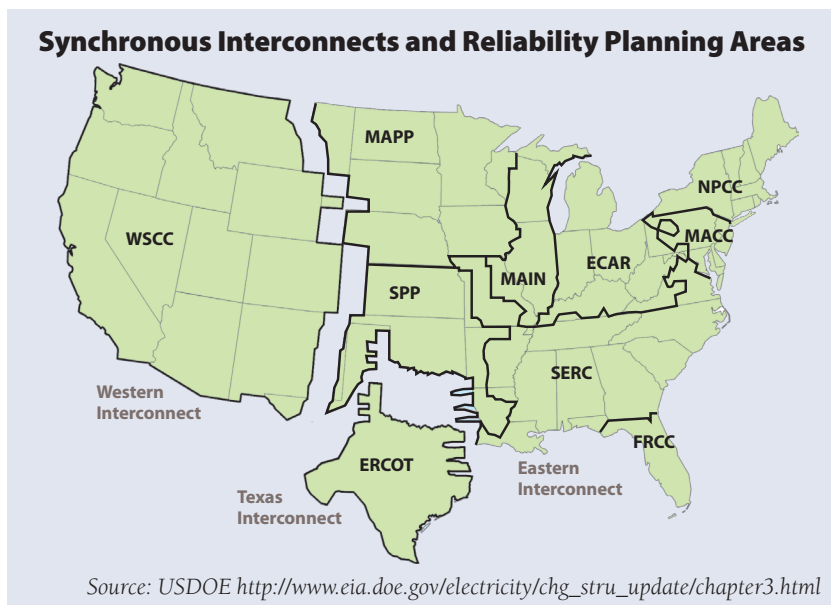
federal authority over the siting of transmission facilities in certain areas or corridors designated under federal law being in the national interest.²² This authority has not yet been used.

By federal law, the transmission system is accessible to any generator that wants to use it. This is accomplished commercially through an **open access transmission tariff** (OATT). The OATT is approved by FERC.

FERC also has jurisdiction over wholesale system planning. In 2011 FERC issued an order, known as Order 1000, has the effect of requiring transmission operators to cooperate with neighboring systems and to consider state policy on such matters as renewable energy and energy efficiency in the process.

This transmission system has been upgraded in some operational areas with select advanced **smart grid** technologies. Operators now have improved awareness of the state of the system through more and better sensors, and electronic devices, such as phase angle regulators and flexible AC transmission systems (FACTS), that give operators some control over power flows. Still, right-of-way maintenance and management of trees and vegetation remains a critical factor in the performance of transmission systems.

Figure 3-5



22. FERC was given limited authority in the Energy Policy Act of 2005 to step in where state siting authorities have withheld approval for transmission lines for a period of at least one year and where the US DOE has designated a National Interest Electric Transmission Corridor after analysis.

3.9. Managing Power Flows Over the Transmission Network

Power must generally be produced at the same time it is consumed. Large batteries and other storage systems such as pumped storage dams are methods to store electricity, but are expensive.²³ In most grids, the real time balancing of customer demand and system supply requires sophisticated control of power plants and transmission lines to provide reliable service. A number of organizations manage the flow of power over the transmission network. The continental United States (along with most of Canada and a bit of Mexico) is divided into eight reliability planning areas, under the oversight of the **North American Electric Reliability Council** (NERC). NERC has adopted specific reliability standards for transmission reliability that are legal requirements under FERC authority.

3.9.1. RTOs, ISOs, and Control Areas

Within the NERC regions, many entities manage minute-to-minute coordination of electricity supply with demand: **regional transmission organizations** (RTOs), **independent system operators** (ISOs), and individual utility **control areas**.

Regional transmission organizations and independent system operators are similar. Both are voluntary organizations established to meet FERC requirements. ISO/RTOs plan, operate, dispatch, and provide open-access transmission service under a single **tariff**. Each is the control area for its region, assuming this role for all transmission owning members. The ISO/RTOs also purchase balancing services for the transmission system, and they manage various markets for energy and other grid services.

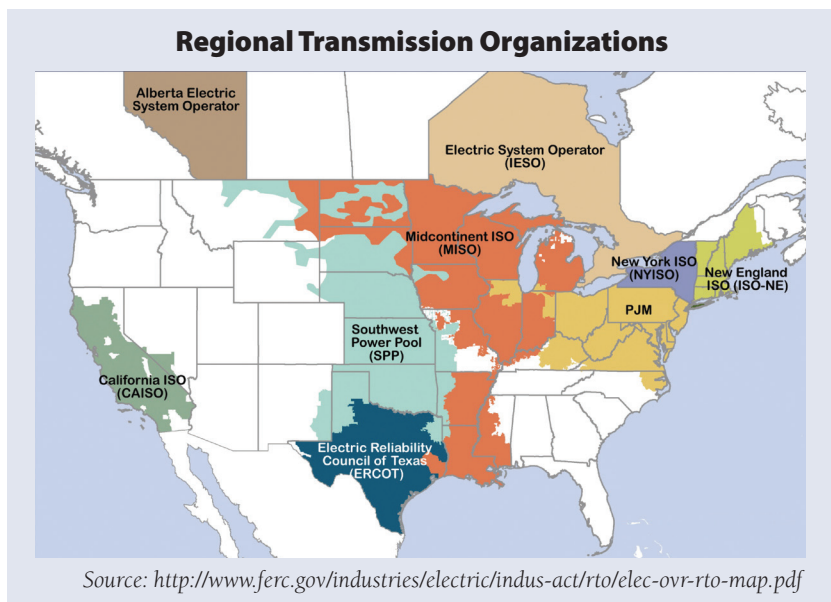
To accomplish their mission, ISO/RTOs must have functional control of the transmission system. Their purpose is to foster competitive neutrality in wholesale electricity markets and reliability in regional systems. Transmission owners then turn over control of their systems in exchange for federal tariffs that recover costs plus a return on investment.

In 1996, FERC articulated 11 criteria that ISOs would need to meet in order to receive FERC approval.²⁴ Four years later, FERC had approved (or conditionally approved) five ISOs, but it had also concluded that further refinements were needed to address lingering concerns about competitive neutrality and reliability. ISOs grew out of Orders 888/889, in which the Commission suggested the concept of an ISO as one way for existing tight power pools to satisfy the requirement of providing nondiscriminatory access to transmission.

23 Storage technologies are evolving, and the economics are improving. See Chapter 16.

24 Order 888, FERC Stats. & Regs., 1996.

Figure 3-6



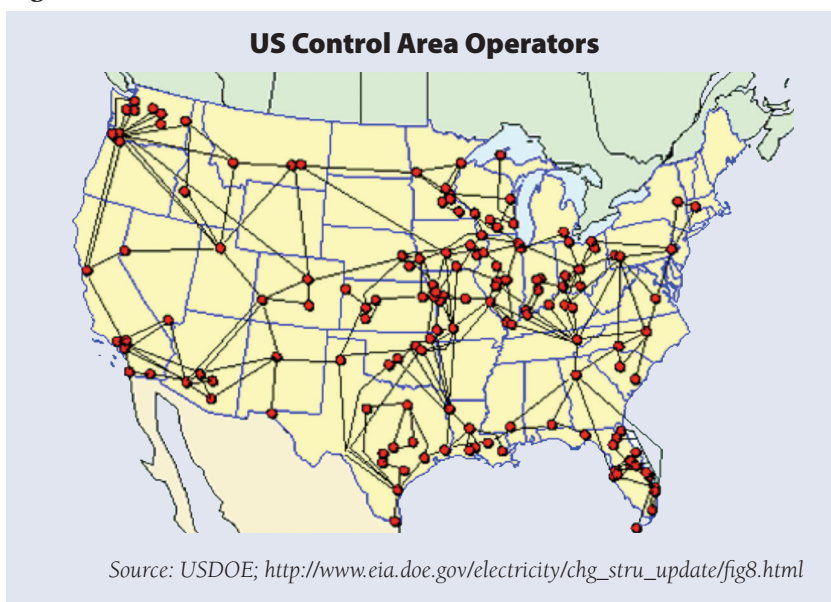
In 1999, FERC issued Order 2000 establishing non-mandatory standards for RTOs. Again, it did not mandate an obligation to form RTOs; instead, it simply laid out the 12 elements that an organization would have to satisfy to become an RTO. Many of the features mirrored the earlier ISO requirements. As of October 2010, seven organizations had been approved as either an ISO or an RTO. As ERCOT in Texas is isolated from the rest of the US grid, it is overseen not by FERC but by the Texas Public Utility Commission (PUC).

Some parts of the country are served by RTOs, and some by ISOs. Some, mainly in the west and southeast, are not served by either. Because an RTO is a voluntary organization, participating transmission owners can exit or enter. Thus, the national RTO map is also subject to change.²⁵

Some grid areas within each NERC reliability planning area are managed by individual utilities, mostly large investor-owned ones, and some by the federal power marketing agencies. These are called control areas or balancing authorities. In the Western interconnection, there is no region-wide RTO or ISO (the California ISO has recently begun steps to expand to serve utilities to its north and east), and the individual control-area operators must

25 As this section was being published, multiple systems in the western states were negotiating an energy interchange market and possible geographic expansion of the California Independent System Operator.

Figure 3-7



coordinate with each other to ensure region-wide reliability of service.

Although the western United States has had a history of bilateral cooperation between control area operators, the proliferation of wind generation has motivated a new level of interest in some market solutions to managing resources in a least-cost manner. A number of utilities, with support of some state regulators, are implementing an **Energy Imbalance Market** (EIM) that will enable exchanges of excess generation from one part of the west to address high cost or shortage of generation elsewhere in ways that may be more efficient than possible under traditional relationships.

Whether served by an RTO, an ISO, or a utility control area operator, all places have some form of wholesale market for power under the supervision of FERC. A utility market may have a single buyer, whereas an RTO or ISO will tend to have many buyers.

FERC's Order 1000 on regional system planning applies to control area operators, and specifies objectives for inter-control area planning.

3.10. Natural Gas Utilities

Most natural gas utilities do not own their own gas wells or gas transmission pipelines. Utilities typically operate as distribution-only entities, buying gas from multiple suppliers over multiple pipelines to serve their retail consumers. Like electric utilities under restructuring, most natural gas utilities also allow larger consumers to purchase gas directly from wholesale

gas suppliers, and pay the local utility to deliver the gas from the interstate pipeline.

Unlike distribution-only electric companies, however, gas utilities typically buy gas from suppliers, then pass the cost through to consumers in rates without any additional markup or “profit” component. It is common for gas utilities to sell “bundled” supply and distribution service to residential and small commercial customers, but sell only “transportation” service to large users, leaving these customers to negotiate gas-supply contracts with marketers and brokers.

For more information:

Federal Energy Regulatory Commission. *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States*. Retrieved from <http://www.ferc.gov/about/ferc-does/ferc101.pdf>

US Department of Energy, *A Primer on Electric Utilities, Deregulation, and Restructuring of US Electricity Markets*.

4. The Regulatory Commissions

Most state regulatory commissions and FERC follow generally similar procedures. Local regulatory bodies (generally elected city councils or boards) that govern COUs, however, can use very different processes. Regardless of the procedures or standards followed, the regulatory body ultimately performs the same basic functions by:

- determining the revenue requirement;
- allocating costs (revenue burdens) among **customer classes**;²⁶
- designing price structures and price levels that will collect the allowed revenues, while providing appropriate price signals to customers;
- setting service quality standards and consumer protection requirements;
- overseeing the financial responsibilities of the utility, including reviewing and approving utility capital investments and long-term planning; and
- serving as the arbiter of disputes between consumers and the utility.

This chapter discusses the structure and organization of the regulatory commissions. Later chapters discuss how they actually operate.

4.1. Commission Structure and Organization

Most state commissions consist of three to seven appointed or elected commissioners and a professional staff.²⁷ The staff may carry out some or all of the following functions:

- managing their own personnel, facilities, operations: administrative staff;
- conducting hearings: administrative law judges, hearings examiners, attorneys;
- analyzing rate filings through testimony (usually pre-filed): economic, accounting and engineering staff;
- enforcing rules and tariffs: compliance staff, attorneys;

26 Although data are reported to the US EIA in only four classes, Residential, Commercial, Industrial, and Transportation, there is no uniformity in how customers are classified. Nearly all utilities place residential consumers in a separate class. Some try to separate commercial from industrial consumers, whereas others organize business users by size or voltage. Many have separate classes for agricultural and government consumers.

27 Information on state commissions and FERC can be found at the website of the National Association of Regulatory Utility Commissioners, or NARUC. NARUC is a voluntary association of state and federal regulators. See: www.naruc.org

- providing technical assistance to the commissioners: advisory staff;
- legal analysis: attorneys;
- legislative analysis and reporting: policy staff; and
- facilitating alternative dispute resolution processes, including settlement negotiations among parties.

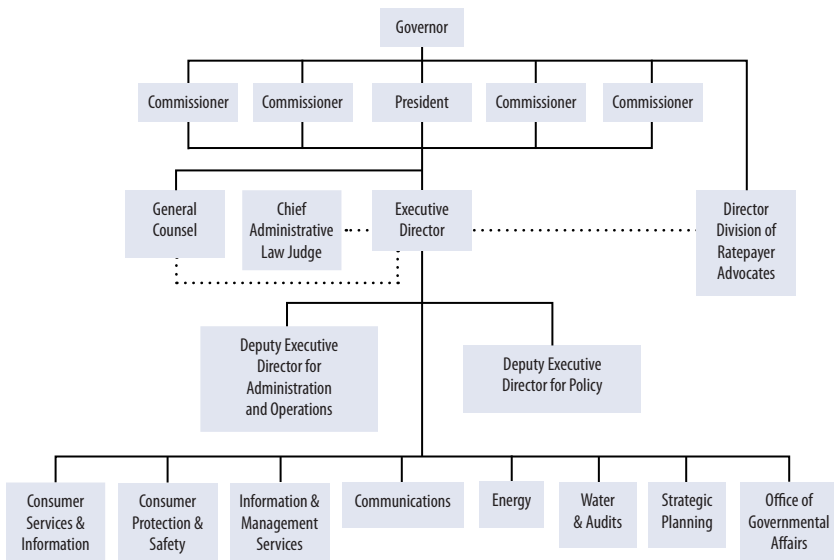
The California Public Utility Commission is organized along functional lines. Although it is larger than most state commissions, its organizational chart provides an illustrative overview of the range of functions that a commission performs.

Not every commission carries out each of these functions. In some states, the commission staff does not prepare any evidence of its own. A few states include the consumer advocate (discussed in more detail shortly) within the commission—but in most states that have a consumer advocate, that office is located in a separate agency, sometimes in the attorney general’s office.

In some states, the commissioners actually sit through hearings and listen to the evidence, asking questions and ruling on motions. In other states, the hearings are conducted before a *hearing officer* (sometimes called a *hearing examiner* or *administrative law judge*), typically an attorney sitting in the role of a judge, who then writes a *proposed order* to the commissioners. The commissioners then may only hear or review arguments on the proposed order before rendering a decision. In some states, both approaches are used.

Figure 4-1

California PUC Organizational Structure



Source: CPUC, 2016

4.2. Appointed vs. Elected

In the majority of states, the commissioners are appointed by the governor, subject to confirmation by the legislature. However, a number of states have elected commissioners. In a few of these, the commissioners are elected by the legislature, although most are elected by voters. In some of the states with elected commissioners,²⁸ very strict rules may govern campaign contributions and conflicts of interest. Most commissioners serve terms of four to six years. In some states there are limits to how many consecutive terms a commissioner may serve.

4.3. Limited Powers

Commissions are limited-power regulators. Their authority is defined by law, and their decisions are subject to appeal to the state courts, generally pursuant to the state administrative procedure act, or federal court, in the case of FERC. In general, courts will defer to the expertise of the regulators, but if they find that regulators have exceeded their statutory authority, misinterpreted the law, or conducted an unfair process, they will take appropriate remedial action.

In a few states, the regulatory agency is established in the state constitution and has constitutional duties and powers beyond the scope of legislative authority, although the legislature may augment the agency's authority or duties through legislation. Among the powers delegated to commissions is the authority to promulgate rules. These can be legislative rules that set specific requirements for utilities or interpretive rules that provide guidance on how the law is to be carried out. Legislative rules, once adopted, usually have the force of law. Courts generally retain to themselves the authority to interpret statutes and regulations, but will defer to reasonable interpretations by the commissions.

In general, state commissions do not regulate consumer-owned utilities, but there are some exceptions.

4.4. Consumer Advocates

Most states have a designated consumer advocate.²⁹ Many of these are housed within the state attorney general's office, but some are located in other agencies or are stand-alone offices with leaders appointed either by the governor or other elected officials. The consumer advocate represents the public in rate proceedings, and generally has a budget for some technical

28 The elections may be statewide or by district. In South Carolina, commissioners are elected by the state senate.

29 In states where there is no state-funded consumer advocate, and for larger consumer-owned utilities, the federal Public Utility Regulatory Policies Act (PURPA) Section 122 provides a framework for intervenor compensation to parties that significantly affect regulators' implementation of the PURPA ratemaking standards.

staff and expert consultants. Some consumer advocates are charged with representing all customers (or at least those not otherwise adequately represented), whereas others are explicitly limited to residential and, possibly, commercial customer classes. Consumer advocates tend to focus on the total **revenue requirement**, the allocation of that revenue requirement between customer classes, and **rate design**. In addition to their focus on rates, some consumer advocates also concern themselves with resource planning and environmental impacts or costs.³⁰

4.5. COU Regulation

COUs typically have very different regulatory structures. City utilities/munis are generally subject to control by the City Council or a special board or committee that may or may not ultimately answer to the City Council. Public power districts generally have dedicated boards, elected by the voters at large. Cooperatives generally have dedicated boards, elected by the consumers of the utility (including business consumers). In general, COUs have much more streamlined processes for setting rates and policies—and sometimes no visible process at all, except for a decision by the governing body in open session.

State public utility laws, however, generally do apply to COUs. These may control elements like the timing of and notice requirements for rate adjustments, resource portfolio requirements, availability of low-income assistance programs, and standards for termination of service for non-payment.

In some states, the legislature has given the state commission regulatory authority over cooperatives and munis. Even where this is not the case, munis and coops are still subject to the intervention, discovery, and other provisions of PURPA when rate design issues are considered. PURPA is discussed in Chapter 6. Where COUs are regulated by state commissions, some requirements applicable to IOUs may be relaxed.

30 More information on state consumer advocates is on the website of the National Association of State Utility Consumer Advocates (NASUCA). See: <http://www.nasuca.org>

5. What Does the Regulator Actually Regulate?

Different regulators control different parts of the utility industry. Some of the regulation is done directly by state legislators and the Congress. Most is done by the FERC and the state Commissions, who use a mix of legislative-style rulemaking and quasi-judicial hearings processes.

First and foremost, regulatory bodies are creations of the legislative branch of government. They have only the powers that are vested in them by the Congress or the state legislatures. Although these powers may be broad, they are not unlimited. Many regulatory commissions have issued decisions that have later been reversed by courts as exceeding the authority of the regulator.

At the federal level, FERC has authority over hydropower licensing, interstate transmission tariffs and rules, and wholesale power sales, although in Texas, Alaska, and Hawaii, where there are limited (or no) interstate connections,³¹ it only regulates licensing for construction and operation of power-producing dams.³² FERC transmission regulation is discussed in Chapter 13. Nuclear power plant design, construction, operational safety, and nuclear material are regulated by the Nuclear Regulatory Commission. FERC also has jurisdiction over utility mergers, typically sharing with the Securities and Exchange Commission, other federal agencies, and affected states.

The state regulatory commission normally regulates all IOUs in a state. In most but not all states, municipal utilities and public power districts are not

31 An interconnection encompassing multiple states is considered to be in interstate commerce, and therefore within FERC's jurisdiction, when the power flows on both sides of the state line are synchronous. To avoid FERC jurisdiction for most of the state, Texas (through ERCOT) has limited interconnection between the core area of the state and other utilities across state lines to so-called back-to-back DC interconnections, through which power is converted from alternating current to direct current, transferred to the adjacent synchronous interconnection, and then converted back to alternating current. In this case, the transaction over the direct current intertie is actually FERC jurisdictional, but the interconnection behind the direct current intertie in Texas is not considered to be in interstate commerce. Portions of the state near the periphery, outside of ERCOT, are fully interconnected to adjacent states and are actually part of the control areas of utilities based out of state.

32 Hydropower regulation is beyond the scope of this guide. More information on the regulation of power producing dams may be found at www.ferc.gov/industries/hydropower.asp.

subject to any economic regulation by the state utility regulator; they are still subject to regulation by statute. In about 20 states, cooperatives are subject to some form of state regulation.

Depending on state law, local cities and counties may control local transmission and power plant siting. In most states, however, one or more state agencies are responsible for issuing permits necessary to build and operate generation and transmission, pre-empting local authorities. The local government within which the utility operates generally also regulates such matters as the location of poles and overhead wires, and coordination with other utilities on construction. Local land use plans may have some standing to be considered in state jurisdictional siting matters.

Federal, state, and local environmental regulators have authority over land use, air and water emissions, and land disposal of waste from power plants, but this environmental regulation is largely beyond the scope of this guide. Federal regulators also have authority over projects on federal land or those that are undertaken by federal governmental agencies.³³ Additionally, federal regulators have authority over off-shore wind projects and projects under the control of federal management agencies.³⁴

The balance of this chapter deals with the role of the state utility regulatory commission, although the local utility regulators for COUs generally have the same set of powers.

5.1. The Revenue Requirement and Rates

The first and best established functions of the state commission are to determine a utility's revenue requirement and to establish the prices or rates for each class of consumers. The process for determination of the revenue requirement is discussed in detail in Chapter 8. However, in the case of industrial customers with direct access to high-voltage transmission lines, transmission rates set by FERC may represent almost the consumer's entire bill from the local electric utility.

33 The Energy Policy Act of 2005 calls for utility-grade wind and solar energy development on federal land in Section 211, and also calls for west-wide and east-wide energy corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on federal land in Section 368. The National Environmental Policy Act of 1969 (NEPA) requires federal agencies to consider environmental impacts of their proposed actions and evaluate reasonable alternatives to those actions. Such an impact would be evaluated through an environmental impact statement (EIS). The Energy Policy Act therefore triggers a review under NEPA for large-scale energy projects. Additionally, natural gas pipelines and other projects undertaken by the federal government may trigger a NEPA review.

34 For example, Cape Wind, the offshore wind farm off the coast of Cape Cod, is currently undergoing review under NEPA, the Massachusetts Environmental Policy Act, and other environmental statutes. Projects undertaken by federal management agencies, such as the BPA, also trigger review by federal regulators.

5.2. Resource Acquisition

The commission generally has some authority over the utility's choice of power sources to serve its consumers, but that authority varies greatly from state to state.

Portfolio Standards. Many state legislators, commissions, and voters have adopted energy portfolio standards, which require utilities to meet a certain percentage of their sales with designated resource types, generally a defined set of renewable ones.³⁵ Some states have explicitly required utilities to meet a portion of power needs by reducing demand through energy efficiency programs.

Integrated Resource Planning (IRP). An IRP is a long-term plan prepared by a utility to guide future energy efficiency, generation, transmission, and distribution investments. Some commissions require IRPs and review the plans. IRP is discussed in Chapter 15.

Construction Authorization. Many state commissions have the authority to consider and approve, or reject, proposed power plants. Some states require a specific approval (sometimes called a certificate of public convenience and necessity, or CPCN). Others may use an IRP process to determine whether construction of a power plant is necessary, and some use a combination of the two (see Chapter 15 for a discussion of these).

Prudence. Once a power plant or other capital project is completed, the commission may conduct a prudence review to determine if it has been constructed or implemented as proposed, according to sound management practices, and at a reasonable cost and with reasonable care. This review may compare utility performance to a previously reviewed set of goals, or it may be prepared on an ad hoc basis for a specific project.

Energy Efficiency. About half of the states have directives related to energy efficiency. Energy efficiency is typically the least expensive way to meet consumer needs for energy services. Some states have adopted mandatory energy efficiency standards for buildings, appliances, and other equipment. Utility-funded investments in energy efficiency pay for measures that benefit the utility system, but the energy efficiency measures would not otherwise be implemented by consumers for a host of possible reasons. Even when investments in efficiency are not required by state law, most state regulators have adopted policies and principles that set criteria for making investments in efficiency measures, and provide a mechanism for recovery of the investments made by utilities (or other designated administrator).

35 About half of the states, totaling about 75 percent of the nation's population, have renewable portfolio standards or energy efficiency standards of some type. The definition of eligible resources varies by state. See: <http://www.dsireusa.org/resources/detailed-summary-maps/>.

General Authority. Regulators are usually broadly empowered to “regulate in the public interest” and this has resulted in some regulators taking on issues that others do not. This may include some aspects of environmental regulation,³⁶ economic justice, or long-run reliability planning. This power is not unlimited; it is constrained by the enabling statutes.

5.3. Securities Issuance and Utility Mergers and Acquisitions

When a utility seeks to issue additional stock or bonds to finance or refinance its investment in utility facilities, in many states it must get permission from the regulator. This ensures that the terms of the securities that will likely become part of the rate base are reasonable, and also ensures that the utility does not indebt itself in such a way as to harm its access to capital. Access to capital at reasonable cost is essential to the utility’s ability to provide safe and reliable service, especially in the event of a major failure (e.g., storm damage or an unplanned plant outage) or for major construction projects.

A merger between utilities, or acquisition of a utility by another corporation, involves a form of securities issuance, and usually affects the utilities capital structure, and therefore normally requires approval of the regulator. Typically mergers must pass a public interest test. In some states a *no-harm* standard is imposed, whereas in others a *net benefit* standard must be met. Over the past two decades, there have been dozens of mergers approved by regulators, usually with specific conditions attached to protect the public interest.

5.4. Affiliated Interests

The regulator generally has authority over the relationship between the utility and *affiliated interests*, meaning a parent corporation, another subsidiary of the utility’s parent corporation, or a separate company that is in some other way deeply intertwined with the utility. These regulations are intended to prevent self-dealing, where, for example, the utility pays above-market prices for services provided to it by an unregulated affiliate or, conversely, it provides services to its unregulated affiliate at below-

36 See Dworkin, M., Farnsworth, D., & Rich, J. (2001, June). The Environmental Duties of Public Utility Commissions. *Pace Environmental Law Journal*, 18(2). Retrieved from <http://digitalcommons.pace.edu/cgi/viewcontent.cgi?article=1564&context=pejr>

37 Migden-Ostrander, J. (2015, December). Power Sector Reform: Codes of Conduct for the Future. *Electricity Journal*, 20(10), 67-79. Retrieved from <http://www.sciencedirect.com/science/article/pii/S1040619015002274>

market costs.³⁷ In both circumstances, the utility is taking advantage of its captive monopoly customers to give its unregulated affiliate an economically unjustified advantage over its competitors. Where regulators have authority over affiliated-interest activities, they generally take care to ensure that utility consumers are not harmed by the often risky actions taken by the unregulated affiliates.³⁸

5.5. Competitive Activities

Regulators may permit utilities to engage in activities that may be competitive in nature. This would tend to occur under tightly managed circumstances and would tend to leverage the monopoly position of the utility to get wide coverage for a service, or nurture accelerated growth of a service. Energy efficiency services could be competitive, yet utilities are in a special position to cover their territories with offers of assistance and support. Solar photovoltaic (PV) systems on customer premises are competitive, yet some suggest that utility involvement will help grow deployment faster, whereas others fear it will impair progress. Some regulators have required that competitive activities be performed by separate subsidiaries, and that the subsidiaries pay a royalty to the regulated utility for the use of the goodwill value of the public confidence that the regulated utility is a trustworthy vendor.

5.6. Service Standards and Quality

Commissions adopt specific standards for voltage, **frequency**, and other technical requirements in electric service, generally based on industry standards. This is generally limited to the distribution service, not to transmission, which is subject to FERC regulation. Commissions may also adopt regulations governing the terms on which service is offered, the charges that apply when lines are extended, and the process by which customers may be disconnected for nonpayment. A few regulators have used their authority to regulate service standards to implement minimum energy efficiency standards for new homes and commercial buildings where local building officials do not make efficiency a priority. With growth in customer generation, primarily solar, regulators adopt standards for interconnection, and may limit new solar connections if it is deemed to pose reliability risk to

38 Perhaps the most extraordinary of these situations was when Enron went bankrupt in 2001. Enron owned several utilities, including Northern Natural Gas and Portland General Electric. Although the consumers of these utilities were adversely affected in terms of price and reliability by the Enron collapse, utility regulators took steps to ensure that catastrophic impacts did not occur. A similar situation occurred in Texas, where Oncor was the distribution utility subsidiary of Energy Future Holdings, which entered bankruptcy reorganization in April 2014.

other customers.

Many commissions have adopted **service quality indices** (SQI) based on specific indicators to measure the quality of utility service, such as the frequency and duration of outages, the speed with which companies respond to telephone inquiries, the speed with which they respond to unsafe conditions, and so on. Service quality is discussed further in Chapter 22.

5.7. Utility Regulation and the Environment

Utility regulation and environmental regulation are increasingly intertwined.³⁹ In most states, the utility regulator is tasked by statute as an economic regulator, leaving the enforcement of environmental laws to separate environmental agencies. In many states, however, the economic regulator nonetheless evaluates environmental costs and risks to consider the appropriate long-term energy resources that best serve ratepayers. In many cases, this economic and risk analysis encourages utility investment in low-pollution alternatives, such as renewable resources and energy efficiency as a prudent long-term investment strategy for the electric sector.

Because the future cost of power to consumers will probably be significantly affected by the environmental impacts of power production, utility regulators are increasingly paying attention to utility resource decision-making through the IRP process (see Chapter 15). Utility regulators are also taking a more active role with respect to the promulgation of environmental regulations by environmental regulatory agencies; in some cases, this is focused only on reliability, and in others, cost and technology diversification play a role.

The Clean Power Plan (CPP), promulgated by the EPA under Section 111(d) of the Clean Air Act, creates challenges for utility regulators assuming it survives court challenges underway in 2016. The CPP imposes emissions limitations on each state, but does not directly affect individual utilities or power plant owners. The EPA rule grants the states broad latitude on the type of system they can adopt and whether they work alone or regionally. Under the 111(d) rules, it is the environmental regulators in the states, operating under a system described as “cooperative federalism,” that will need to determine the best way to achieve cooperation and coordination among the different owners of power plants creating emissions and, in coordination with state environmental officials, determine the best way to meet state targets. The utility regulatory body, which ultimately reviews and allows recovery of compliance-related spending and investments, will necessarily have a role in

39 The Regulatory Assistance Project. (2010, September). *Clean First: Aligning Power Sector Regulation With Environmental and Climate Goals*. Retrieved from <http://www.raponline.org/document/download/id/927>

the multi-utility coordination to minimize total costs for a state.

Decisions by environmental regulators affect utility investment, as states implement plans to meet EPA standards for air, land, and water quality. These are likely to change utility resource strategies. Utilities may seek to recover the costs of their investments through utility regulators; in restructured states, they may pass along the costs of their investments through regional electricity markets. In a few states, the utility regulator has a direct role in some aspects of environmental regulation, primarily the investment by utilities in pollution control equipment.⁴⁰

Chapter 20 of this Guide addresses environmental regulation for the power sector in greater detail.

40 For example, in Washington state, the Energy Facilities Site Evaluation Council (EFSEC) is the permitting agency for major power plants. The Washington Utilities and Transportation Commission is one of the agencies holding a voting seat on EFSEC.

6. Participation in the Regulatory Process

Utility regulators provide multiple avenues for public participation in the process. Some opportunities are complex and legalistic, whereas others more clearly invite citizen input.

This chapter describes the various forums through which consumers, environmental advocates, business groups, and others can participate in the regulation of utility prices, policies, and resource planning. It is important to understand and closely follow rules regarding contact and communications with regulators, especially in the course of formal contested proceedings.

6.1. Rulemaking

Commissions make three types of rules. *Procedural* rules guide how the regulatory process works; *legislative* rules govern how utilities must offer service to consumers; and *interpretive* rules provide guidance on how utility actions will be viewed in future economic regulation. There is normally an opportunity for public comment when rules are proposed or amended. In some states, the legislature or the attorney general may have authority to review and approve proposed rules. Although **rate cases** and other adjudicatory proceedings are subject to courtroom-like procedures, rulemaking activities are generally more interactive, with informal contacts and meetings with the regulators allowed.

6.2. Intervention in Regulatory Proceedings

Intervention in a formal regulatory proceeding is probably the most demanding form of citizen participation. Utility hearings are normally held under state administrative law rules, and function very much like a courtroom. Although an individual may usually be able to participate without an attorney, requirements of the rules of procedure and evidence must nonetheless be met. A consumer or group of consumers must file documents to become an **intervenor**. Although the right of intervention to address PURPA rate-making issues affecting large electric utilities is guaranteed by federal law,⁴¹ regulators may reject or limit intervention on other issues.

41 16 USC 2631

6.3. “Paper” Proceedings

Although utility general rate proceedings normally involve live testimony and cross-examination of expert witnesses, as well as public hearings, many regulatory proceedings are conducted entirely by written submission of proposals, comments, evidence, and argument. These are known as *paper proceedings*. This approach is often used for technical changes to tariffs and service rules.

6.4. Generic Proceedings and Policy Statements

Regulators often convene generic proceedings to examine emerging issues in the industry. These may be structured to involve all of the regulated utilities and stakeholders in a single proceeding that leads to a guidance document to be applied in future proceedings involving individual utilities. Examples may include “utility of the future” investigations, rate design, solar energy, customer service policies, investment in smart grid, and low-income energy services. Sometimes at the conclusion of these investigations, regulators may issue a policy statement to guide parties on the perceptions of the Commission in future dockets.

6.5. Stakeholder Collaboratives

In the past decade or so, many commissions have formed **stakeholder collaboratives** to engage utilities, state agencies, customer group representatives, environmental groups, and others in a less formal process, aimed at achieving some degree of consensus on dealing with a major issue. Commissions may conduct a stakeholder process through an *investigation* or an *inquiry* process that is less formal than an *adjudication*. These collaboratives may meet for a few months or more, then collectively recommend a change to regulations, tariffs, or policies. This approach provides an opportunity for innovation and cooperation on complex technical issues.

6.6. Public Hearings

Utility regulators hold two types of public hearings. Rate cases and select other proceedings are done through formal adjudication, which means the entire process of presenting testimony and cross-examination of witnesses is generally termed a public hearing, but is usually a very technical process not really designed for public involvement. As discussed in Chapter 8, one element of these may be an opportunity for the general public to speak on the issues in the rate case.

In addition, however, regulators often hold less formal (non-adjudicatory) public hearings on matters pending before the commission in a policy investigation or rulemaking context. Public hearings of this type offer the commission an opportunity to hear opinions of the public on the particular

issue before the commission. Anyone may speak at a public hearing. Public testimony at these types of hearings is normally not subject to the evidentiary hearing process, meaning members of the public will not be cross-examined by an attorney or the commission. The commission considers all of the information presented at the hearing, including testimony from the public.

Many regulatory bodies hold periodic “open-mike” sessions in which any person may speak to any issue that is *not* currently before the commission in a formal proceeding. These are opportunities to suggest such things as new approaches to regulation, new utility programs, or new evaluation standards to be applied to utility performance. There is typically no obligation for the commission or any party to give a formal response to an open-mike presentation.

6.7. PURPA Ratemaking Standards⁴²

PURPA, originally enacted in 1978 and amended several times since then, requires each state regulatory commission, and the regulatory body for each large self-regulated utility, to “consider and determine” whether several specific policies should be adopted. The regulators are not required to adopt these standards, but are required to consider evidence and enter a decision. Those decisions can be changed, but the modification of a previous decision can be subject to the same “consider and determine” process.

The standards address:

- Cost of service
- Declining block rates
- Time-of-day rates
- Seasonal rates
- Interruptible rates
- Load management techniques
- IRP
- Investments in conservation and demand management
- Energy efficiency investments in power generation and supply
- Consideration of the effects of wholesale power purchases on utility cost of capital; effects of leveraged capital structures on the reliability of wholesale power sellers; and assurance of adequate fuel supplies
- Net metering
- Fuel sources
- Fossil fuel generation efficiency
- Time-based metering and communication
- Interconnection
- Rate design modification to promote energy efficiency investments
- Consideration of smart grid investments
- Smart grid information

42 16 USC 2621

6.8. Proceedings of Other Agencies Affecting Utilities

Many governmental agencies other than the utility regulator have proceedings that affect utilities. State energy offices⁴³ may make rules affecting resource planning, energy efficiency, or renewable resources. Environmental and land use regulators may control the siting, construction, and operation of utility facilities. In some states, a siting council decides on such matters instead of the commission (although commission staff may also support the siting council, and a member of the siting council may be a commissioner). Safety and labor standards may be administered by other separate agencies, and each type of public agency with regulatory authority may have its own rules, processes, and procedures.

For more information:

NW Energy Coalition, *Plugging People Into Power*.

Rose, K., & Murphy, M. (2008). *Reference Manual and Procedures for Implementation of PURPA Standards in EISA 2007*. Washington, DC: US DOE. Retrieved from <http://energy.gov/oe/downloads/reference-manual-and-procedures-implementation-purpa-standards-eisa-2007>

43 Each state has an agency designated as the recipient of federal State Energy Program (SEP) funding. In most states this is a separate agency, but in some it is incorporated in a larger agency. Most are separate from the utility regulator. The state energy offices are organized under the National Association of State Energy Officials (NASEO). See: <http://www.naseo.org>

7. Procedural Elements of State Tariff Proceedings

A commission's approved conditions, terms, and prices of utility services are published in a document called a **tariff**. A utility submits a proposed tariff change to the regulator. The regulator may approve, reject, or set a hearing to consider a tariff change. Many minor tariff changes are approved summarily or allowed to go into effect automatically without a formal decision at the expiration of a statutory review period.

Significant changes, and rate increases in particular, are given more detailed review. Regulatory commissions primarily review significant revisions to utility rates and various elements of their service in general rate cases. In these rate adjustment proceedings, the commission determines a new rate base, a new rate of return, and new rates for most or all customer classes.

Some states require a general rate case on a fixed schedule (such as every three years), but most do not. With a few exceptions, utilities may request a rate change at any time if they can demonstrate that existing rates do not allow them a reasonable opportunity to earn a fair rate of return. Although most utilities file for general rate increases every two to five years, some utilities have gone more than 10 years without a general rate case. The commission normally has the authority to initiate a rate review on its own motion or by filing a complaint, but this is rare. In theory, an individual consumer or a small number acting together submitting a formal complaint that the utility's rates were not in compliance with the requirements of law (which generally say that rates should be "fair, just, and reasonable") could trigger a general rate review, but this also seldom happens.

When an IOU applies to its regulator for a rate or policy change, it triggers a well-established formal regulatory proceeding. Understanding the steps of the process in advance can help an interested party decide if, how, and when to take action. Figure 7-1 shows a typical procedural schedule; in some states, the schedule is more compressed, and in some situations, the duration can be much more extended.

This chapter describes the procedural elements of a general rate proceeding, that is, who does what and when do they do it. It is intended to help the reader understand the sequence and other formalities of a general rate case.

Figure 7-1

| Typical Schedule for a Major Rate Case | | |
|--|---------------|-------------------------|
| Activity | Calendar Date | Months From Filing Date |
| Notice of intent to file | Jan 15 | -2 |
| Initial filing of tariffs and evidence | Mar 15 | 0 |
| Discovery period ends | Jun 15 | 3 |
| Staff and intervenor evidence due | Jul 1 | 3.5 |
| Rebuttal evidence due | Aug 1 | 4.5 |
| Rebuttal discovery period ends | Aug 15 | 5 |
| Expert witness hearings | Sep 1-20 | 6 |
| Public witness hearings | Sep 25-27 | 6.5 |
| Briefs due | Nov 1 | 7.5 |
| Commission decision | Dec 15 | 9 |

7.1. Scope of Proceedings

The Commission sets the scope of a proceeding. The utility may request a rate increase, but in the order setting the matter for hearing, the Commission may expand the scope of the docket. Sometimes the regulator initiates a proceeding to consider significant policy issues. Because the regulatory process is part legislative and part adjudicative, it is quite common for regulators to expand the scope of a “rate case” to include resource planning issues, customer service issues, or energy efficiency issues. The fact that there is a trial-type proceeding to consider evidence does not detract from the broad discretion given to commissions (state and FERC) to regulate in the public interest. Commissions can make policy through rulemaking or through case-by-case adjudication.

7.2. Notice and Retroactive Ratemaking

Most states require utilities to give customers formal notice when a rate change is requested. This may be in the form of a bill insert, advertisements, or other means. Sometimes a rate increase may go into effect on a *subject to refund basis*, meaning that if the increase is not ultimately approved in full, the excess collection will be refunded to customers with interest. Normally a rate adjustment applies only to consumption after the date the rate change is approved. This often requires a pro-rated bill, with some consumption charged at the previous rate.

7.3. Filing Rules

Most commissions have specific *filing rules* that specify the information and public-notice requirements associated with a utility's request for a change in rates or other tariff terms. For example, the Washington Utilities and Transportation Commission's rules define a "general rate case" as one in which the utility is requesting more than a three-percent increase in overall revenues, and require detailed information to be submitted with the initial request. Applications involving smaller changes in rates, or changes affecting only a small number of consumers, are sometimes subject to less-detailed filing requirements.

7.4. Parties and Intervention

There are *statutory parties*—those whose right to participate in a commission proceeding is established in law—such as the utility, the commission staff, and the consumer advocate. Other participants, or *intervenor*s, such as representatives of industrial consumers, low-income consumers, and environmental groups, are granted the right to participate by the commission, sometimes after demonstrating a particularized interest that is not better represented by the statutory parties. Most commissions have rules that set out the terms of permissive intervention, when petitions to intervene must be filed (typically at the very beginning of the process), and the intervenors' obligations. Typically intervenors must attend hearings, answer discovery requests (see next section), file required documents in a timely fashion, and be respectful of the legal aspects of the process. Sometimes commissions ask parties with similar interests to cooperate or consolidate.

As discussed in Chapter 6, a federal law, PURPA, gives consumers of large electric utilities a statutory right to intervene in any proceeding relating to rates in which issues addressed in PURPA (relating mostly to rate design) are considered. Although this law appears to guarantee a right to intervene, it does not prevent the commission (or local regulator of a COU) from setting rules regarding intervention in other types of proceedings, or from determining whether the PURPA ratemaking standards are at issue in any given proceeding.

7.5. Discovery

When a utility seeks a change in the tariff and the commission schedules a hearing, the utility must provide information to the parties. Commissions establish guidelines as to the form in which parties may request information from other parties (as well as the utility). These are called *discovery requests*, *interrogatories*, *data requests*, *requests for production* (of documents), or *information requests*. The commission also sets deadlines for the required responses to these requests.

Some of the information requested may be commercially sensitive or protected from public disclosure by law. In these situations, the utility may refuse to provide the information, or may request a *confidentiality agreement*. The commission then decides what must be disclosed and the terms of disclosure. Parties that are granted access to confidential information assume a continuing duty to follow rules relating to handling and storage of documents, must take steps to protect the documents and information from unauthorized disclosure, and may be required to certify that all confidential materials were returned or deleted at the end of the proceeding.

Intervening parties may also have information of interest to the utility, or other parties. All parties are generally subject to discovery requests.

7.6. Evidence

All parties to a tariff proceeding may submit evidence, presented by witnesses. Evidence normally takes the form of pre-filed written testimony and exhibits. Testimony expresses the position of the witness, whereas exhibits contain detailed factual support, technical analysis, and numeric tables and worksheets. Before 1980, testimony was often delivered orally at the hearing, and in many states it is still written in question-and-answer format as though it were a transcript of oral direct examination by an attorney.

Direct testimony and exhibits are normally filed by the utility at the time it makes its tariff request. The commission then sets a schedule for when other parties must file their direct evidence. The applicant, normally the utility, is allowed to submit *rebuttal* evidence, which is evidence that the utility provides to rebut some evidence or testimony submitted by another party. In some cases, parties other than the utility can rebut one another in what is known as *cross-rebuttal* testimony. Sometimes additional rounds of *surrebuttal* evidence—evidence in response to rebuttal evidence—are allowed.

7.7. The Hearing Process

The hearing process allows the attorneys, or non-attorney representatives, of the parties to ask questions “on the record” of the expert witnesses. All of the evidence is given under oath (subject to the penalties of perjury) and recorded in a transcript. The degree of formality varies somewhat among the states. Commissions adopt procedural rules governing the conduct of hearings.

In most states, after all the direct and rebuttal evidence is filed, all of the witnesses are scheduled in a single hearing process that may take days or weeks. Some state commissions hold hearings in stages, as the evidence is submitted: the applicant’s direct evidence first, followed by a gap in time, then the testimony of other parties, then finally the rebuttal evidence. The hearing allows for the formal admission of testimony and evidence into the administrative record. The hearing may occur before the regulatory

commissioners, or before an administrative hearing officer who ultimately makes a proposal for decision to the commissioners.

7.7.1. Expert Testimony

Persons presenting detailed technical testimony and exhibits under oath are typically called *expert witnesses*, although rules for qualification of experts are less formal than in legal court cases. Expert testimony is ordinarily scheduled in advance, so that the other parties can be prepared to question specific witnesses on specific dates. Sometimes commissions will group witnesses by topic—for example, scheduling all of the cost-of-capital witnesses during a single day or week. The schedule is generally made after asking each party how many hours of questions they will have for each witness, and in consideration of the schedule of witnesses who must travel or have other conflicts.

Generally the administrative nature of the hearing and the pre-filing of testimony prevents the kind of courtroom dramatics often seen on television. Expert witnesses may be questioned as to their actual expertise on the topic. Although few commissions completely dismiss evidence if a witness is found to lack genuine expertise, such a situation definitely affects the weight given to the testimony. Intervenors are well advised to make certain that their witnesses do not go beyond the scope of their expertise.

In rare instances, the commission may use its power to subpoena witnesses and compel their testimony in a proceeding.

7.7.2. Public Testimony

Nearly all commissions also set aside a time, in hearings on major rate increases or other important proceedings, for testimony from the general public. This opportunity may be limited in time, typically to three minutes or less, depending on the number of people who want to speak. In large cases, commissions may require speakers to consolidate their remarks. Sometimes public testimony is received at the beginning of the process, as soon as the applicant's direct evidence is available. Sometimes they come after all of the parties have testified, and the issues have become more focused; this option is generally more effective for intervenors who want their members and supporters to speak at the public hearing.

In some states, members of the public speak under oath, but they are not required to be experts and they may speak to any topic being addressed in the proceeding. However, it is important that supporters understand the basics of the process: hearings are conducted like a court proceeding, and a courtroom demeanor is important. The commission may not give the same weight to public testimony as it does to expert testimony, especially

of witnesses who are not subject to questioning from the parties, but there is no question that public participation in the hearing process can affect the result. A large turnout with a clear, concise, relevant message can inform a commission's decision where the evidence and law allow the commission some discretion to craft an equitable resolution.

7.8. Settlement Negotiations

Once the testimony of all parties is filed (or even before), it is common for the parties to enter into settlement negotiations, with the goal of presenting an agreed position on all issues (or a partial settlement on some issues) to the commission. In some states, the commission by rule or by order requires an attempt at settlement discussions.

Settlement negotiations give intervenors an opportunity to have an important influence on the final result. All parties normally participate in settlement negotiations, and having an all-party settlement is important because it increases the likelihood that the commission will approve the settlement and thereby put an end to the formal hearing process. This saves all of the parties the time and expense of the expert-witness hearings. It also typically gets the utility a rate decision sooner than going all the way through the 6- to 12-month hearing process.

Although settlements can bring an efficient conclusion to a proceeding, if there is a string of settlements over a long time, the commission may lose touch with the evidence. This is one reason a commission or a consumer advocate may decide to reject a settlement and continue the formal process. Another concern commissions sometimes have is a “black box” settlement, in which the conclusion is clear, but the trade-offs different parties made are not. Commissions are sometimes presented with a settlement in which the parties explain that any changes will void the settlement. This situation may chafe commissioners who may object to some element, or who may see an opportunity to improve the deal. Commissions at this point sometimes risk stating that they will only approve the settlement if certain changes are made, challenging the parties and their flexibility.

Partial settlements are also possible, in which some issues are resolved through negotiations and a smaller subset of issues are addressed in the hearing process.

7.9. Briefs and Closing Arguments

If the proceeding goes all the way through the expert-witness hearing stage, the parties file final briefs and make final closing oral arguments to the commission once the hearings are complete. These summarize the evidence and describe how it supports their positions.

7.10. Limited Purpose Proceedings

Regulators frequently consider dockets that are on narrow subjects, or involve changes in policies rather than of rates and prices. These proceedings may be subject to a greatly abbreviated intervention, evidence (or no evidence at all, just briefs covering legal and policy arguments), and closing argument framework. Some may not even be conducted as formal adjudications. Examples of this approach include changes to energy efficiency or line extension tariffs, dockets for approval of specific investments, or proceedings that affect a limited number of customers.

7.11. Orders and Effective Dates

After reviewing the record, the commission will deliberate and issue a final order. In some states the deliberations are open to the public and in others they are not.

In states where the hearing is held before an administrative law judge or hearing examiner, the examiner will typically release a *proposed order* detailing a recommended resolution of the contested issues. The parties then file written exceptions to the proposed order, indicating where they believe the record supports a different conclusion. The proposed order and the exceptions are reviewed by the commission, which then issues a final order. The order will specify a date when the rates may take effect.

Generally the parties have the opportunity to file motions for reconsideration or clarification of an order before considering an appeal.

Sometimes a commission will allow rates to take effect prior to the conclusion of the proceeding; in these cases, the rates are allowed to go into effect subject to refund, meaning that if the commission subsequently decides that a lower rate increase is appropriate, the utility will have to refund the difference to consumers. This process is sometimes used when the commission cannot complete its analysis before the deadline imposed by state law. These interim rates are often referred to as “bonded” rates.

7.12. Appeal

Any party that believes the commission has deviated from that which is allowed by law may appeal the order to the courts. In general, the courts defer to the expertise of the regulatory body, especially on the resolution of factual issues, but will reverse or remand a decision if they find it clearly violates some principle of law.

For more information:

Chesapeake Bay Foundation. *How to Write and Present Testimony*. Retrieved from <http://www.cbf.org/Document.Doc?id=302>

8. Fundamentals of Rate Regulation: Revenue Requirement

This chapter summarizes the analytic process that a regulatory commission follows in a general rate proceeding.⁴⁴ Because commissions are supposed to set rates that provide utilities an opportunity to earn a reasonable rate of return of and on prudent investments, and recovery of reasonable expenses, they need to determine the utility's costs for providing service in their state. This includes both the costs associated with the rate base (the utility's investment in facilities and related capital costs, including interest on debt and a return on equity) and its operating expenses (labor, fuel, taxes, and other recurring costs).

This chapter and the two that follow it are the most technical and lengthy part of this guide. It takes the reader through the key elements of a general rate case. These include determining the overall level of expenses and investment to be recovered in rates, determining the appropriate rate of return (profit and interest), and then dividing the required revenue between customer classes and developing rates to recover that revenue. It ends with a discussion of a few of the minor issues that commissions deal with in these cases. Most states have a process that considers all of these issues, although each commission does this a little bit differently.

8.1. Functional and Jurisdictional Cost Allocation

Some utilities have multistate operations, are part of holding companies with both regulated and non-regulated operations, or have more than one regulated service (such as both natural gas and electric operations). In these cases, the regulator must first determine what investments and expenses are associated with the service that is the subject of the rate case. State regulators have no "jurisdiction" to determine rates in another state, or for federal purposes, but state-level decisions can indirectly affect rates in other jurisdictions, potentially complicating rate cases and other proceedings.

⁴⁴ The terms *rate proceeding*, *general rate case*, and *rate case* are used interchangeably to refer to the regulatory proceeding wherein a commission considers an application for an increase in utility rates—one that increases the total amount of money received, and generally applies increases to all or most of the customer classes served by the utility. There are *limited issue* proceedings that may not involve all the analysis of a general rate case.

8.1.1. Interstate System Allocation

When a utility serves more than one state, the commission conducting the proceeding must decide which facilities serve its state. In general, regulators allocate costs according to how those costs are caused. Identifying distribution facilities and expenses is fairly straightforward, because they are located in specific states and serve only customers in that state. Allocating a utility's costs for administrative headquarters, production, and transmission investments and expenses can be more controversial. Over time, most states have developed methods for interstate allocation that are considered to be fair in their jurisdictions, although in rare instances the total amount allowed in each state does not add up to the total of the company's actual operations. In the case of some multistate utility holding companies, FERC determines the allocation of generation and transmission costs between jurisdictions.

Commissions split production and transmission costs (including the investment in generating facilities and transmission lines, the operating costs of those facilities, and payments made to others for either power or transmission) based on various measures of usage. Some costs are assigned in proportion to each area's share of **peak demand** (the highest usage during a period) and others according to energy consumption (total kWh during a period), using principles similar to those used to allocate costs between customer classes. Administrative facilities are generally allocated in proportion to some combined measure of the number of customers in the state, the state's share of the utility's peak demand and energy use, and occasionally its share of total utility revenues. Federal taxes are normally divided proportionally, on the basis of taxable income, among all states in a system.

State and local taxes are more complex. Property taxes associated with distribution facilities that serve only one state are normally assigned to that state. However, a power plant located in one state and subject to property tax there may serve consumers in several states; it is fair for all the consumers who benefit from the facility to pay their share of its property taxes.

8.1.2. Regulated vs. Non-Regulated Services

Many utilities are also part of larger corporations that engage in both regulated utility operations and non-regulated businesses, which may or may not be energy-related. Although most costs relate only to specific business units such as the electric or gas utility, some are common to all the corporation's activities, such as the expenses for officers and the board of directors, for corporate liability insurance, and for headquarters facilities. The commission may need to allocate a portion of these administrative costs to the state utility, leaving the balance assigned to the parent company or to other states. Non-regulated operations are typically riskier business ventures,

and the commission must carefully allocate the costs so that utility consumers do not bear these risks. Allocation of these costs requires an assessment of relative risks and relative benefits, and can become highly contested.

8.1.3. Gas vs. Electric

Utilities that provide both gas and electric service (and sometimes telecommunications and even steam heat) need to have their shared investments in the rate base and operating expenses separated, so that electric rates cover only the costs of providing electric service, and gas rates only those of gas service. Formulas that are typically used for dividing the shared costs will consider the numbers of customers, the amount of plant investment directly associated with each service, the labor expenses associated with each service, and the total revenue provided by each service.⁴⁵ If the service territories for electricity and gas are not the same geographically, these allocations can be quite complex and controversial.

8.2. Determining the Revenue Requirement

Most of the evidence in a rate case is directed at determining the revenue requirement, or the total amount of revenue the utility would need to provide a reasonable opportunity to earn a fair rate of return on its investment, given specified assumptions about sales and costs. The utility is most concerned with this; the other elements of a rate case divide that total allowed revenue among different customer classes and among consumers within classes, and do not affect the utility's overall profit.

The basic regulatory formula for determining the revenue requirement is given in Figure 8-1. Operating expenses (including taxes and depreciation expense) are recovered on a \$1 for \$1 basis. If, for example, the rate of return is set at ten percent, a ten percent return on the amount of investment is recovered in rates each year until the investment is fully depreciated over its accounting lifetime.

Figure 8-1

The Basic Revenue Requirement Formula

$$\text{Rate Base Investment} \times \text{Rate of Return} + \text{Operating Expenses} = \text{Revenue Requirement}$$

Each of these is described in greater detail below.

⁴⁵ Approaches vary widely from state to state and even utility to utility. This isn't surprising, given that economic theory offers little guidance on the allocation of joint and common costs. A commission's judgment and sense of fairness are called for in exercises such as this.

8.2.1. The “Test Year” Concept

Rate cases are based on the concept of a **test year**, which presents the costs and revenues of the utility on a defined annual basis. The test year may be a recently completed actual year, or may be a future, estimated year. All the costs for the rate base, operating expenses, and sales revenues are computed for the same period, so that total costs can be appropriately compared with total revenues, with the full effects of weather and other annual impacts included, to determine if there is a revenue deficiency (or a revenue surplus, implying that a rate decrease is appropriate). After actual costs are quantified, adjustments to test year costs may be proposed to reflect known and measurable changes.

8.2.2. Historical vs. Future Test Years

A *historical test year* takes as a starting point the actual investments, actual expenses, and actual sales of the utility for a recently completed 12-month period. The utility proposes adjustments to the recorded data to bring them up to date, reflecting known and measurable changes in costs that have occurred since the test year or which are reasonably expected to occur before the new rates take effect. Known and measurable costs can be evaluated through evidence.

A *future test year* (sometimes called a *forecasted test year*) is an estimate of the same data for a future period, usually based on detailed budgets and expected changes in costs that are subject to examination by the commission. Typically the future year is the first year the proposed rates would be in effect.

In either case, the investment in a major addition to the rate base such as a new power plant may be reflected in the test year, so that the new rates will enable the utility to recover those costs in the future when that plant will be providing service (i.e., when it will be **used and useful**). In general, *used* means that the facility is actually providing service, and *useful* means that without the facility, either costs would be higher or the quality of service would be lower. However, each state has its own regulatory history that determines what is allowed to be included.

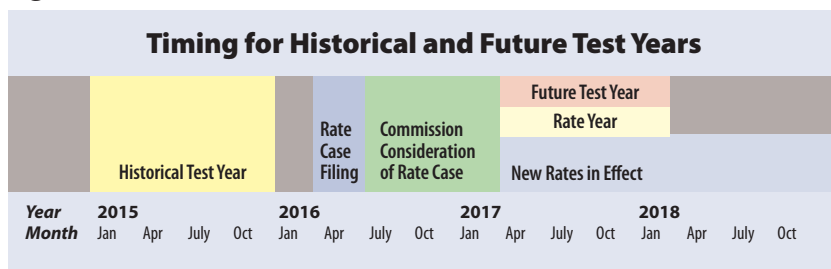
Finally, the term *rate year* is sometimes used to denote the first full year in which new rates will be effective. This term is used even in historic test-year jurisdictions, but typically would be about the same period that would be used for a future test year.

The theory is that, in a given year, whether historic or future, revenues, expenses, and rate base will “match.” That is to say that they reflect actual or anticipated relationships at a given point in time. Over time, of course, the revenues may change with customer growth or changes in usage. However, if sales, expenses, and investment change in the same proportion, then there should be no shortfall or windfall to the company.

The historical test year approach is generally accurate when costs are relatively stable over time, and inflation is offset by productivity improvements. Future test year estimation, especially when combined with more frequent rate cases, may be better suited to more dynamic economic conditions, such as periods with high inflation rates. But future test year rate-making requires much more scrutiny by the regulator because an overstated forecast of costs or understated forecast of sales will produce a windfall for the utility.

Figure 8-2 depicts a typical period for a historical test year of 2015, a rate filing in the second quarter of 2016, consideration of the filing for nine months, and both a future test year and a rate year beginning in the second quarter of 2017.

Figure 8-2



8.2.3. Average vs. End-of-Period Rate Base

When historical test years are used, the utility may seek to adjust all investments and all expenses to the level in effect at the end of the 12-month period. This is called an *end-of-period rate base*. However, traditional accounting principles generally recommend using the average rate base (typically the average of the 12 monthly average investment levels, using the beginning of month and end of month balances) for the year, because that more accurately reflects the entire time during which the revenues were (or will be) collected. New facilities and expenses may have been added during the year to serve new customers that come onto the system, but these also generated new revenues.

8.2.4. Rate Base

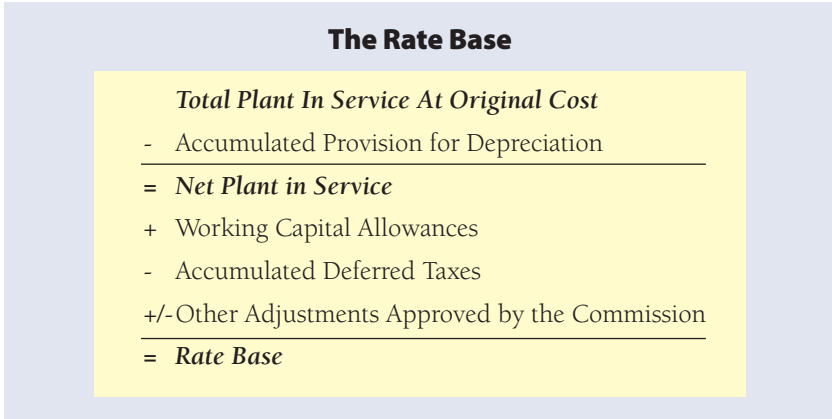
The **rate base** is the total of all long-lived investments made by the utility to serve consumers, net of accumulated **depreciation**. It includes buildings, power plants, fleet vehicles, office furniture, poles, wires, **transformers**, pipes, computers, and computer software.

The rate base also includes some adjustments for working capital and deferred taxes. It may also include adjustments for certain deferred costs

(such as *regulatory assets*) incurred by the utility in furtherance of regulatory or policy objectives. The term *rate base* is sometimes erroneously used to mean the entire revenue requirement, but in fact the term applies only to the investment in long-lived assets used to provide service (adjusted for working capital, regulatory assets, and deferred taxes).

The basic formula for the utility's rate base is given in Figure 8-3. The variables entering into the formula are described in more detail below.

Figure 8-3



Generally, to be allowed in rate base, an investment must be both used and useful in providing service and prudently incurred. The utility has the burden of proving that investments meet these well-established tests, but often enjoys presumption of use and usefulness, and prudence in the absence of evidence to refute it.

Working capital is the amount of cash the utility must have on hand to pay its bills when they are due, because consumers will normally not pay their utility bills until some time after they receive service.⁴⁶ Although it is not invested in hard assets that provide service, the utility is using this capital for the benefit of the consumers, and it is therefore allowed to earn a return on it.⁴⁷

46 Some utilities have moved to prepayment systems, in which some consumers pay for power before they use it. Under these circumstances, a working capital credit (reduction) should be applied to the rate base for the customer classes or sub-classes subject to prepayment.

47 Like all capital, working capital has a time value. If it were not being used to cover the utility's costs until the revenues are received through payment of customers' bills to cover those costs, the capital would be put to other productive uses on which a return can be earned. Thus, the return that working capital earns is the opportunity cost of foregoing those other uses.

Deferred income taxes reflect provisions in federal tax laws that allow utilities to collect money for taxes years before they actually pay them. Consumers have paid these taxes to the utility before the utility pays them to the government—so the utility, in effect, has a balance that the shareholders and bondholders did not provide; consumers did. Reducing the rate base by the amount of the previously paid taxes means that consumers pay lower rates over time, because part of the utility's investment is being supported with ratepayer-supplied funds.

Other adjustments may include ratepayer-supplied capital (such as payments made for line extensions), allowed *construction work-in-progress*, investments in terminated projects allowed into rates, and other minor elements. Some of these reduce the rate base, whereas others increase it.

8.2.5. Rate of Return

Utilities are allowed the opportunity to earn a regulated annual rate of return on their rate base. Legal precedent requires that rate to be sufficient to allow the utility to attract additional capital under prudent management, given the level of risk that the utility business faces. Two key US Supreme Court decisions, known as *Hope*⁴⁸ and *Bluefield*,⁴⁹ set out the general criteria that commissions must consider when setting rates of return. In *Hope*, the Court found that “*under the statutory standard of just and reasonable standard, it is the result reached, not the method employed, that is controlling.*” This allows regulators considerable flexibility, so long as they reach a reasonable result. In *Bluefield*, the Court found that utilities are entitled to a fair return, but not the kind of return that investors in speculative or risky ventures expect to receive.

Several different sources of funding provide capital for the utility, and the commission sets different rates of return for each source (shareholder equity, bondholder debt, and some others). Debt receives a lower rate of return than equity, because the debt holders bear less risk; they have the first call on the utility's revenues after operating expenses, before any dividends can be paid to stockholders. Short-term debt also generally carries lower interest rates, because the lender is not making a long-term commitment to the utility.⁵⁰

48 *Federal Power Commission v. Hope Natural Gas Company*, 320 US 591 (1944) (“*Hope*”).

49 *Bluefield Water Works and Improvement Company v. Public Service Commission*, 262 US 679 (1923) (“*Bluefield*”).

50 During the hyperinflation period of 1977 to 1982, short-term interest rates exceeded long-term rates, but both were dramatically higher than any period before or since.

8.2.5.1. Capital Structure

The utility's *capital structure* consists of the relative shares of its capital that are supplied by each source: common equity, preferred equity, long-term debt, and short-term debt. Because these all have different cost rates, the mix greatly affects its overall (weighted) rate of return and costs to customers. In addition, because the utility is subject to income tax on its return on equity, and gets an income tax deduction for its interest payments on debt, a higher share of equity quickly calculates to higher rates for consumers. The commission rules on the capital structure because it is an essential element in the calculation of the revenue requirement.

In general, US utilities have between 40 and 60 percent debt, and between 60 and 40 percent equity. There is no “right” level of equity. In Canada, for example, equity ratios are more typically around 30 to 35 percent, reflecting higher investor confidence in the certainty of utility earnings, so the utility can more easily attract bond investors and use lower-cost debt to provide a higher percentage of its total capital.

Utilities typically carry some short-term debt; this is incurred as small period borrowings under a bank line of credit, and then periodically extinguished when a larger sale of equity shares or mortgage bonds takes place. Different regulators treat short-term debt in different manners; some associate it exclusively with new plant under construction, whereas others treat it as part of the general capital structure.

The commission's approved capital structure is often different than the utility's actual capital structure, especially where the company has significant non-utility operations or has excessive or insufficient equity in its capital structure. (In such cases, the approved version is called a *hypothetical* or *imputed* capital structure.) A utility will sometimes seek an allowed capital structure with more equity than its current level, in effect asking to increase its equity ratio. This can be problematic, because if it does not actually achieve the allowed share of equity, it collects revenues for shareholder equity costs (and income tax costs) that it does not actually incur.

The utility's case for its preferred capital structure is typically made by expert witnesses based largely on prevailing trends in the utility industry and capital markets.

8.2.5.2. A Generic Rate of Return Calculation

The basic formula for rate of return (with each element separately determined by the commission) is given in Figure 8-4, and Figure 8-5 provides an illustrative example of a rate of return calculation. The cost of debt may be easily ascertained based on actual interest rates on outstanding bonds, and prevailing market conditions for new issuances. Other values, like the “cost” of common equity, include considerations of the rate of return that

Figure 8-4

| The Generic Rate of Return Formula | | | |
|---|--|------------------------------------|---------------------------------|
| | Percentage of Capital Structure | Cost of Capital for Element | Weighted Cost of Capital |
| Common Equity | A % | B% | A% x B% |
| + Preferred Equity | C% | D% | C% x D% |
| + Long Term Debt | E% | F% | E% x F% |
| + Short Term Debt | G% | H% | G% x H% |
| + Other | I% | J% | I% x J% |
| = Rate of Return | 100% | | Sum |

Figure 8-5

| Hypothetical Rate of Return Calculation ⁵¹ | | | |
|--|--|------------------------------------|---------------------------------|
| | Percentage of Capital Structure | Cost of Capital for Element | Weighted Cost of Capital |
| Common Equity | 45 % | 10% | 4.50% |
| + Preferred Equity | 5% | 8% | 0.40% |
| + Long Term Debt | 45% | 7% | 3.15% |
| + Short Term Debt | 5% | 5% | 0.25% |
| = Rate of Return | 100% | | 8.30% |

makes utility stock sufficiently “attractive” to investors without providing an unjust windfall to those investors at ratepayer expense.

8.2.5.3. Cost of Common Equity

The return on (or cost of) common equity is typically one of the most hotly contested issues in a rate case, in part because there is no precise way to measure it.⁵² Although the cost of debt and preferred stock are usually

51 Not all regulators include short-term debt in the capital structure; some ascribe all short-term debt to the allowance for funds used during construction (AFUDC).

52 Although the public generally perceives the return on equity as the utility’s “profit,” in the rate-case context it is usually referred to as the cost of equity, because it is the amount the utility must pay an equity investor in order to use the investor’s money, just as interest on debt represents the cost of borrowing from a bond investor.

set in advance, and precise data on what the utility will actually pay for those sources are known, the return to common stockholders must be determined in light of expert opinions about market conditions at the time of the rate case and over the period during which the rates will be in effect. Conceptually the allowed return on equity is the return that the utility must offer to investors to get them to invest in the company. In recent years, most commissions have determined this to be around 9 to 11 percent (after the utility's federal income taxes are covered), but it has ranged as low as 6 percent and as high as 16 percent in the past. Typically each of the major parties in a rate case presents an expert witness on the appropriate level for the allowed return on equity.

When actual market conditions deviate from expectations a great deal, either the utility or the commission may initiate a new rate case to reset the rates.

Several methods are used to estimate the cost of equity, each based on economic theory and decades of research. Some experts use a weighted combination of several approaches. Some commonly used methods include:

- **Discounted Cash Flow (DCF):** Estimates the present value of the earnings an investor in an equivalent company would receive over a long period of time
- **Equity Risk Premium:** Measures the premium that investors require to make higher-risk equity investments compared with lower-risk bonds
- **Capital Asset Pricing Model (CAPM):** Uses a statistical measurement of the relative risk of the utility company, compared with risk-free investments like government bonds

Commissions sometimes consider the results of multiple methods, and ultimately use their own judgment to determine a “fair” rate of return on common equity. For some methods, identifying comparable companies is important, and some judgment is used. For example, for a utility with a **decoupling** or other revenue stabilization mechanism (explained in greater detail in Chapter 19), using comparable companies with comparable mechanisms is desirable.

8.2.5.4. Cost of Debt

Utilities finance part of their investment with debt, because debt is often lower in cost than equity and because interest payments on it are treated as a cost of business for tax purposes. A utility's debt is usually a mix of long-term debt (bonds) and short-term debt (bank borrowings and/or direct short-term loans from mutual funds or other companies called “commercial paper”). Utilities routinely use some level of short-term debt, because they need unpredictable amounts of capital at any given time. The cost of debt is the

average cost of the utility's borrowed funds for the test year.

Although the cost of equity is always an estimate of what the market requires, utilities do have actual debt outstanding, and actual interest rates on that debt can be exactly calculated, except in the relatively rare situation in which a utility issues variable-rate debt. Particularly in states that use future test years, however, the commission sometimes estimates the cost of debt that will be issued in the near future, and includes this in an estimated cost of debt.

One issue is that utilities may request that a “hypothetical” capital structure that is different from their actual capital structure be used for setting rates. Usually this means a higher equity ratio and lower share of debt. Some regulators have conditioned rate increases on utilities actually achieving these capital structures.

In recent years, average costs for long-term utility debt have been around 5 to 7 percent, but during the dramatic inflation years of the early 1980s they reached 12 percent or more.

8.2.6. Operating Expenses

Operating expenses include labor, power purchases, outside consultants and attorneys, purchased maintenance services, fuel, insurance, and other costs that recur regularly. They also include state and federal taxes and depreciation expense, which is discussed below. The regulatory standard for operating expenses generally assumes an expense is necessary and prudent unless it is demonstrated to be inappropriate.

Some operating expenses are sporadic. Storm damage is an example—in some years, there may be no storms, whereas in others weather may be severe, causing millions of dollars in damage and repair costs. Rate case expenses are another example of sporadic costs, because utilities do not have rate cases every year. For these types of costs, a multiyear average is typically allowed as an expense in the rate case, not the amount actually incurred or projected for the test year.

Some operating costs vary continuously and unpredictably (like those for fuel and purchased power). Most states provide for these cost shifts through automatic changes to rates, under formulas called **adjustment clauses**. Many have other adjustment mechanisms or **tariff riders** dealing with other costs, such as those for nuclear decommissioning, infrastructure replacement, and energy-efficiency program expense. Some adjustment mechanisms provide for dollar-for-dollar recovery of actual expenditures, whereas others operate under formulas designed to give the utility an incentive to control costs. (Adjustment clauses are discussed in Chapter 14.)

8.2.6.1. Labor, Fuel, Materials, and Outside Services

Most operating expenses cover labor, fuel, materials, and outside services—costs that are directly associated with providing service. Typically most of these expenses are only evaluated by the commission in a general rate case. Imprudent, improper, and excessive expenses may be reduced or disallowed. Most commissions exclude costs that are not required to provide service, such as charitable contributions by the utility, political lobbying expenses, and image-building advertising

8.2.6.2 Taxes

Utilities also pay a variety of taxes, including federal and state income taxes, property taxes, and, in many states, gross revenue taxes. Normally these are all included in allowed operating expenses. In many cases, local cities and counties also impose franchise fees or gross revenue taxes. Because they are location-specific, these are often added to customer bills in these specific communities, rather than being included in the statewide revenue requirement.

8.2.6.3. Depreciation

Although the rate of return is a return on capital (a payment for the use of facilities), depreciation is the return of capital (as it is used up) to the utility's investors. Utility facilities wear out, and utilities are allowed to accrue depreciation expense to pay for eventual replacement costs. These are non-cash operating expenses—the utility does not actually pay them to anyone every year. Instead the utility collects depreciation over time, and uses the funds to retire debt (or even buy back stock), or to reinvest in new facilities to provide continued service.

Accounting for depreciation expense takes two forms: *operating expense* and *reduction to rate base*. First, it is included as an operating expense on an annual basis in determining each year's revenue requirement. Second, as the utility accrues depreciation over the life of a plant, the built-up balance is applied as a reduction to the rate base, so customers are only paying a rate of return on the remaining value of those investments. In this manner, consumers pay for long-lived equipment over its entire operating lifetime.

When a unit is finally retired from service, both the plant in service and the offsetting accumulated provision for depreciation are removed from the rate base. If they are exactly equal, which they should be, there is no change in the revenue requirement unless the asset is replaced with a more expensive (or cheaper) unit.

Amortization is slightly different from depreciation. Whereas depreciation is the recovery over time of a capital investment in a tangible plant that provides service, amortization is the recovery over a period of years of an investment

in intangible plant. An example is the payment to a city for entering into a franchise agreement, or the investment in an abandoned power plant that no longer provides service, but for which the regulator has determined that recovery of the investment from consumers is appropriate.

Both amortization and depreciation attempt to address fairness to consumers and the utility over time, and to avoid rate shocks from imposing sudden increases in rates.

8.2.7. Tax Issues

The allowed depreciation rate for tax purposes is often different from the depreciation rate for rate-making purposes, owing to accelerated depreciation tax provisions. In this situation, the amount the utility collects in the revenue requirement for federal income taxes may greatly exceed the amount actually paid. In addition, utilities that are owned by holding companies often have corporate tax rates that are much lower than the standard income tax rate included in the utility revenue requirement. These are known as *phantom taxes*. Where they are allowed, the theory is that such tax timing and actual tax cost windfalls belong to investors because their capital is at risk. Some states, such as Oregon, prohibit the inclusion of hypothetical tax rates in the revenue requirement. The argument for denying tax windfalls is that utilities are supposed to operate and charge rates on actual cost of service. Other states accrue the difference into a calculation adjusted over time, and use that amount to reduce the allowed rate base, in a provision for what is known as **accumulated deferred income taxes**.

Some states have allowed more rapid—accelerated—depreciation of obsolete plant, such as coal-fired power plants or analog meters, in order to allow the utility to recover the investment, and retire the asset from service earlier and replace it with better technology sooner. This approach was first used in the telephone industry, as computer-controlled switches became more economical to buy than the cost of maintaining previous electromechanical switches. This approach was last used extensively when states were exploring or adopting “deregulation” and transitions to **retail choice** models. Today many utilities find themselves holding large **fixed cost** investments and declining sales growth, and some have begun to seek regulatory relief to recover those investments.

8.2.8. Treatment of Carrying Costs During Construction

Utilities invest in power plants, transmission lines, and other assets that sometimes take several years to complete. Traditional regulation only allows assets to be included in rate base, upon which the revenue requirement is based, if they are “used and useful,” a term that has been defined by different courts in different ways. But regulators normally do allow utilities to accrue

carrying costs on multiyear projects during the construction period; this is a deviation from conventional accounting. The accrual of an “allowance for funds used during construction” or AFUDC is the normal method used. When the asset actually enters service, the rate base reflects not only the construction cost but also the accrued AFUDC.

Some regulators allow some projects to be included in rate base during the construction period, and earn a current return in the revenue requirement; this is usually called “construction work in progress” (CWIP). CWIP has been very controversial, particularly when the assets are not ever completed. This was an issue for coal and nuclear power plants in the 1980s, and it is still being used by a few states to support nuclear construction. This is done when legislatures or commissions determine that the long lead times and high capital costs would create too much financial risk for the utility unless the carrying costs of the investment are collected from consumers during the construction period. CWIP generally violates the matching principle of regulation, because the costs are incurred by consumers at a different time than the service from plants under construction is received.

8.3. Summary: The Revenue Requirement

The end result of the commission’s analysis is a determination of rate base, rate of return, and operating expenses. Together these determine the revenue requirement. Rates are then set at a level designed to recover the revenue requirement, based on sales levels in the test year.

9. Fundamentals of Rate Regulation: Allocation of Costs to Customer Classes

Once the revenue requirement is determined (as discussed in Chapter 8), the commission next decides how each class of consumers should contribute to meeting the revenue requirement, based on the usage characteristics of each class.

Not all states use the same categories for customers. Some have separate classes for single-family and multi-family residential consumers, on the theory that the cost of serving apartment buildings is lower because more customers are served by a given amount of investment. Some have agricultural classes; some have institutional classes for government buildings; others have special classes for unique needs—for example, to provide power to cruise ships when they dock (these are sporadically used but very large connections). Street lighting is typically a separate class, because it has unique usage characteristics. Determining the right customer classes for each utility is important, and no single method is right for all systems.

Some costs are allocated based on the number of customers, some on the basis of their peak demands, some on their total energy consumption, and some on other aspects of usage. There are as many ways of doing this as there are analysts doing cost-allocation studies, and no method is “correct” for every utility. Often a commission will consider the results of multiple studies, and make an informed judgment that considers all of them.

9.1. Embedded vs. Marginal Cost of Service Studies

Cost of service studies use complex arithmetic models, and their methods are highly controversial. This section gives only a very general overview of the two generic kinds of studies used.

Embedded cost studies rely on the same costs used to determine the revenue requirement—that is, the historic accounting costs (or future test year costs in jurisdictions that use a future test year)—and divide those costs among the customer classes earlier. They assign each cost that makes up the revenue requirement to the various classes of customers, so that the total for all customer classes equals the revenue requirement. Rates are then developed within each class to produce the allocated revenue requirement. About 30

states rely on embedded cost studies to allocate costs.

Marginal cost studies are very different. First, they calculate what it would cost to provide incremental (additional) service at the current costs of adding facilities and acquiring additional power. This may come to more or less than the utility's actual costs, both because of inflation (that is, changes up or down in prices throughout the economy) and because the utility may not have exactly the right mix of resources and facilities to serve its current needs. Marginal cost studies then apportion the revenue requirement between the classes, in proportion to the costs each class would pay if the utility expanded, based on the **incremental costs** of adding to the system rather than the average costs of the existing system. About 20 states use marginal cost studies to set rates.

Although in each category there are dozens, perhaps hundreds, of different methods for determining the relevant costs and their allocations, the results of marginal and embedded cost studies are, in broad terms, similar. Residential and small-business customers are assigned higher total costs per kWh of usage, because they require more distribution investment and generally have usage concentrated in the on-peak periods of the day and year. Industrial customers are assigned lower total costs per kWh, because they require fewer distribution facilities and usually have more uniform usage patterns. If the costs of new facilities are dramatically different than those of existing facilities, however, the results of a marginal cost study can vary significantly from those of an embedded cost study.

If a marginal cost approach is used, the commission needs to be aware of the differences between short-run marginal costs (costs that shift immediately with changes in demand, given a fixed amount of production capacity and distribution plant) and long-run costs. In the long run, all costs are variable—the utility will have to replace power plants and transmission and distribution lines over time, and will hire new and different staff to provide service.

If the time horizon in a marginal cost study is too short, the results may be very different from the results of an embedded cost study, because the investment costs associated with eventually replacing long-lived power plants and transmission lines may be excluded in whole or in part. If the utility is in a surplus or deficit power situation, using short-run marginal costs may distort the results by shifting costs between customer classes unfairly. Reliance on short-run marginal cost when a utility has a surplus of generating capacity may also result in rates for incremental usage that are so low as to encourage additional consumption, which in the long run will require new investments at higher cost.

Some states use a hybrid approach, using embedded costs to allocate costs between classes, and then using marginal cost information to design rates within classes.

9.2. Customer, Demand, and Energy Classification

In both embedded and marginal cost studies, costs are apportioned based on the number of customers, the peak demand, and the total energy usage. The choice of how to allocate each type of cost typically requires judgments on the part of the commission and is often heavily contested in rate cases.

The customer count and energy usage for each class are known with great accuracy, but the peak demand is sometimes estimated, because detailed **peak load** metering is only available if utilities have invested in **smart meters** and the associated **meter data management system** software needed to process smart meter data. There are many measures of demand as well, including the system **coincident peak demand**, the **distribution system** demand, and the individual customer demand; all of these are different, and the choice of which measure of demand is used can have a significant impact on the study results.

For a typical US electric utility, residences make up about 90 percent of the customers, represent about 50 percent of the **system peak demand**, and use about 40 percent of the energy sold.⁵³ As a result, costs allocated based on the number of customers will fall overwhelmingly on the residential class, and those allocated on peak demand fall more heavily on residential and small commercial customers than on large-use commercial and industrial users. Costs allocated based on energy usage fall equally on all classes of customers, in proportion to their kWh (or therm) usage. For these reasons, residential representatives in rate cases often advocate for a heavier weighting to *energy usage* in the cost classification debate, whereas industrial representatives often advocate for a heavier weighting to *customer* and *demand usage* factors.

The classification of distribution system costs between the customer, demand, and energy categories is a very controversial element of this process—and judgment is involved in the ultimate classification decisions. Many of these costs do not directly vary with any of these factors—they are related to the system density of the service territory, the need to maintain clearances over roadways, and other factors. If costs are classified as customer-related, they are then often used to justify high monthly **fixed charges** in the rate design, under the presumption that all customers should contribute equally to these costs, rather than in proportion to usage. If costs are classified as demand-related or energy-related, they are apportioned between classes based on usage, and generally result in higher demand and energy charges in the rate design phase of the process.

53 Customer and energy sales data are reported annually by the US Energy Information Administration. All these usage factors can vary widely from utility to utility.

For the purpose of allocating demand-related costs, some studies define *peak* as only a few hours of the year, whereas others consider the highest **peak demand** in each of several months of the year or the highest 200 or more hours of the year. (There are 8,760 hours in each year.) Some studies divide energy costs by season or by time of day; others do not. Different definitions of peak can have very different impacts on specific customer classes. For example, air-conditioning users contribute to summer peak demands but not winter demands, and a 12-monthly-peak method assigns them much less cost than a summer-peak method. To further complicate issues, for example, some residential customers who have electric heat contribute to winter peaks, but much less for residential customers who have gas heat. Ideally, as discussed in Chapter 10, the same definition of “peak” should be used for cost allocation as for rate design.

Because baseload power plants are so expensive, in both relative and absolute terms, their costs are invariably highly contested elements in the allocation debate. These hydropower, nuclear, and coal plants, and associated long-distance transmission lines, are typically a big part of the revenue requirement for a vertically integrated electric utility. Their high initial cost is justified because the units are used day and night. Baseload power plants have low fuel costs compared with peaking power plants like natural gas turbines, which cost less to build but more to run. If these incremental investment costs for baseload power plants are treated as *demand-related*—as needed to meet peak period requirements—then most of the cost will be borne by residential and small business customers. But if the costs are treated as *energy-related*—incurred to meet total year-round usage—then more of the cost will be borne by large commercial and industrial customers.⁵⁴

54 The treatment of capacity costs in excess of the lowest-cost capacity (e.g., single cycle gas turbines) as energy-related is justified by system planning imperatives. Electricity, which cannot be inexpensively stored, must be produced on demand. Therefore, the system must be designed to meet peak load, that is, the highest combined, instantaneous demand. This is, in effect, a reliability standard and, if it were the only criterion to be met, the planner would opt for that combination of capacity that satisfied it *at the lowest total capacity cost*. This would, very likely, produce a generation portfolio of combustion turbines. However, the system must also be capable of meeting customers' energy needs across all hours. Although combustion turbines cost little to build, they are very expensive to run, such that the average total cost (capacity and operating) per kWh will be high, in comparison to the average total costs of other generating units whose capacity cost is greater than that of the turbine, but whose energy (operating) cost are lower, often significantly lower. Such units become cost-effective, relative to the alternatives, the more they operate. Given this general characteristic of generating facilities (i.e., low capital cost units typically have higher operating costs and vice versa), it will make economic sense to substitute capital (fixed investment cost) for energy (variable fuel cost) as hours of operation increase. As a result, it is right to see those incremental capital costs as incurred not to meet peak demands, but rather energy needs.

In restructured regions, where customers buy electricity from sellers other than the distribution utility, the costs of power supply are almost always presented as purely volumetric per-kWh prices. They often vary by season and by time of day, but both capacity costs and energy costs are bundled into a simple-to-understand per-kWh price.

The treatment of variable renewable power plants (mostly wind and solar) is also sometimes contested. These may not provide reliable capacity at particular hours, but provide a predictable amount of energy at a predictable cost over the course of a year.

9.3. Smart Grid Costs

There are many benefits associated with smart grid investments, but there are also costs. These costs include smart meters, data collection networks, meter data management software, and distribution automation equipment. Together with **smart appliances**, load controls, and time-varying pricing, these can help achieve line loss reductions, peak load reductions, improved reliability, and reduced operating costs for meter reading and outage repairs. **Distributed generation** (DG) and storage devices are often said to “reverse the flow” of electricity on the grid, or create a two-way flow of electricity. The

Figure 9-1

| Allocation of “Smart Grid” Costs | | | | |
|---|------------------------------------|----------------------------|---------------------------------|----------------------------|
| Smart Grid Element | Pre-Smart Grid Element | “Traditional” FERC Account | Traditional Classification | Smart Grid Classification |
| Smart Meters | Meters | 370 | Customer | Demand/Energy/ Customer |
| Distribution Control Devices | Station Equipment | 362 | Demand | Demand/Energy |
| Data Collection System | Meter Readers | 902 | Customer | Demand/Energy/ Customer |
| Meter Data Management System | General Plant | 391-397 | Subtotal of Customer and Demand | Demand/Energy/ Customer |
| Smart Grid Managers | Customer Accounts Supervision | 901 | Customer | Demand/Energy |
| Energy Storage Devices (Batteries; Ice Storage) | Installations on Customer Premises | 371 | Customer | Demand/Energy |

techniques used to allocate the lower costs of the “dumb grid” may not be appropriate for a smart grid. Figure 9-1 identifies several elements of smart grid investment, their function, the FERC account in which they may be recorded, and the appropriate basis for cost allocation of both dumb grid and smart grid investments.

9.4. Vintaging of Costs

Some commissions reserve certain low-cost resources for particular classes of customers. These types of set-asides may reserve limited low-cost hydropower to meet the essential needs of residential consumers, or choose to treat a specific power plant as serving a specific industrial customer whose demand “caused” its construction.⁵⁵

Figure 9-2

| Town of Northfield, Vermont Electric Rates | | |
|--|---------------------------|------------------------------|
| Element | Rate (as of May 29, 2016) | Costs Covered |
| Customer Charge | \$8.01/Month | Metering and Billing |
| First 100 kWh/Month | \$.076/kWh | NYPA Hydropower and Delivery |
| Over 100 kWh | \$.150/kWh | Other Power and Delivery |

In the country as a whole, industrial loads have grown slowly or declined as we have transitioned to a service economy; at the same time, commercial (retail and office) loads have grown rapidly. Some regulators have apportioned the cost of new facilities built to serve growth to the customer classes with the most rapidly increasing demands for service, so that slow-growing loads do not bear the cost of expensive new resources needed to supply growing demands.

55 For example, many utilities in Vermont reserve low-cost hydropower to provide the first block of usage by residential consumers. Above that level, residential customers paid higher rates based on non-hydro power costs; non-residential consumers did not get any allocation of the low-cost hydropower. See http://www.northfield-vt.gov/text/Electric_Department.htm for an example. The state of Maryland assigned a specific low-cost coal plant to a specific aluminum smelter, excluding it from rate increases for new facilities. Similar approaches have been used at times in the Pacific Northwest, in California, and by the TVA.

9.5. Non-Cost Considerations

As these examples imply, rate setting, and especially allocation decisions, can be partly judgmental and partly political, not just technical. Commissions do apply considerations other than cost when setting rates. Much of their action is guided by law; but that law also gives them a certain degree of discretion, although abuses of that discretion may well be overturned on appeal. Commissions may seek to encourage economic development by offering lower rates to new or expanding industrial customers. They may want to limit rate increases to residential consumers, who vote. Bonbright identified the need for **gradualism** to be a guiding principle when rates are rising, with the rationale that sudden large rate changes should be avoided where possible to avoid undue new burdens on some classes of customers. This is especially true where one or more classes appear to be paying an excessive or insufficient share of the total revenue requirement. In the end, regulation is not purely an arithmetical science.

Much administrative law is focused on addressing the authority of agencies, like utility commissions. The questions most commonly raised on appeal include whether the commission properly followed the requirements of law or its own regulation, whether the commission was within its authority in determining the “public interest,” whether evidence before the commission was adequate to support the commission’s decision, and whether the commission properly respected the rights of the utility and other parties.

For more information:

Bonbright, *Principles of Public Utility Rates*.

Lazar, J., & Gonzalez, W. (2015, August). *Dividing the Pie: Cost Allocation, the First Step In the Rate Design Process* [Appendix A of *Smart Rate Design for a Smart Future*]. Retrieved from <http://www.raonline.org/document/download/id/7766>

Lazar, J. (1992). *Electric Utility Cost of Service Analysis*. Prepared for the Arizona Public Service Commission. Retrieved from <http://www.raonline.org/document/download/id/7765>

10. Fundamentals of Rate Regulation: Rate Design Within Customer Classes

Once the revenue requirement and cost allocation are completed, the last important topic that regulators address in a general rate case concerns the design of the retail rates paid by specific customer classes. Rates can include a fixed, recurring monthly (or daily) **customer charge** and energy charges and **demand charges** (the distinction is explained below), as well as other miscellaneous charges relating to the impacts of customer loads on **power quality**. These other charges often vary according to season and time of day.

Essentially every element of a rate is derived from an allocated portion of the revenue requirement divided by a “billing determinant” such as kWh, kW, or the number of customers.

Regulators usually address rate design issues as part of a general rate case, but may undertake separate proceedings to study rate design issues separately from the revenue requirement and cost allocation issues. As a general principle, taking up one rate at a time is frowned upon as “piecemeal ratemaking” (for more on this, see Chapter 11) because of the likelihood of interactive impacts on all customers that typically follow from adjustments of one rate. For example, a simple rate discount for one customer can lead to a revenue shortfall that will be “made up” in another rate for a different customer. All state regulators, and all large utilities, are required to adopt policies and standards with respect to rate design.

10.1. Residential Rate Design

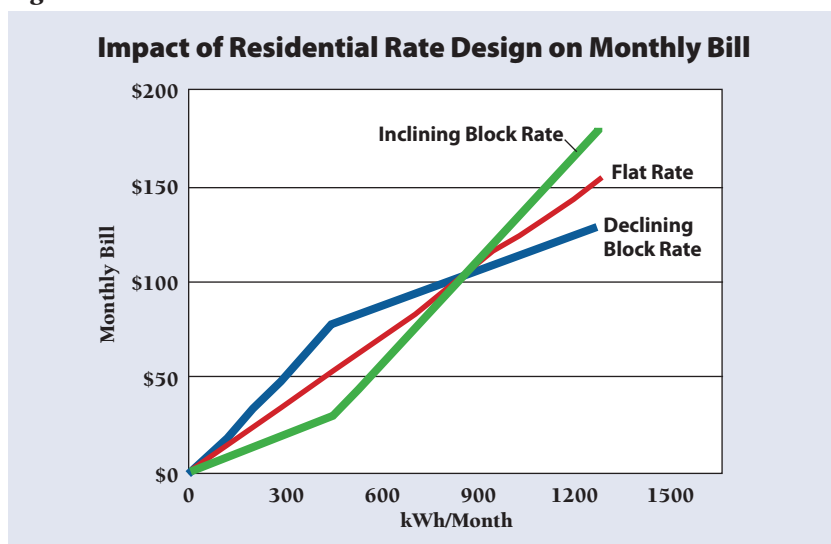
Residential rates typically consist of a monthly customer charge (sometimes called a basic charge or service charge) plus an energy charge in cents per kWh based on the amount of usage. This energy charge may be a **flat rate** (the same for all usage), inclining (with higher rates for usage over a base level), or declining (with lower rates for usage over a base level). Other variations, like differing rates over time or season, are also possible.

As the following example shows, these three basic rate forms affect consumers who have different usage levels quite differently, even though a

Figure 10-1

| Illustrative Residential Electric Rate Design | | | |
|---|-----------|----------------------|----------------------|
| | Flat Rate | Inclining Block Rate | Declining Block Rate |
| Customer Charge | \$5.00 | \$5.00 | \$5.00 |
| First 500 kWh | \$0.10 | \$0.05 | \$0.15 |
| Over 500 kWh | \$0.10 | \$0.15 | \$0.05 |
| Customer Bill | | | |
| 0 kWh | \$5.00 | \$5.00 | \$5.00 |
| 500 kWh | \$55.00 | \$30.00 | \$80.00 |
| 1,000 kWh | \$105.00 | \$105.00 | \$105.00 |
| 1,500 kWh | \$155.00 | \$180.00 | \$130.00 |

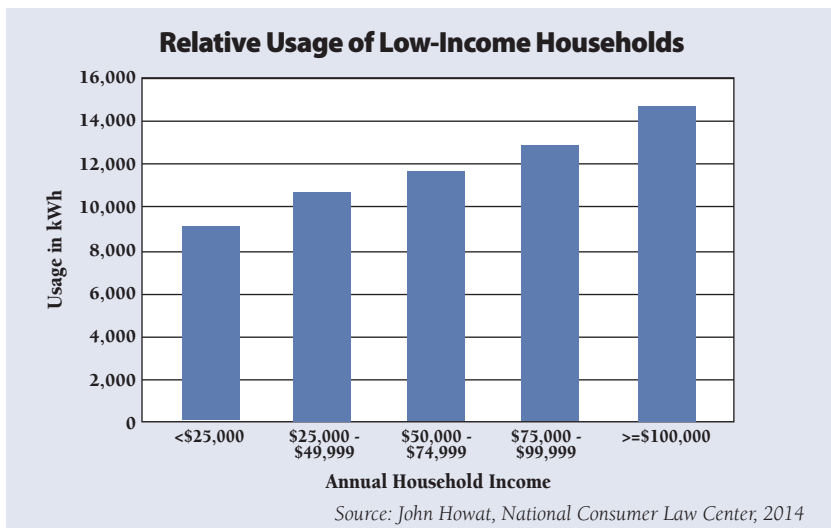
Figure 10-2



consumer using 1,000 kWh/month pays the same total usage charges under each rate design.

The difference between these types of rate design can significantly affect customer usage. Compared with a flat rate, an **inclining block rate** can reduce usage by five to ten percent as consumers respond to the higher incremental cost for power, whereas a high fixed charge (and accompanying lower energy charge) or **declining block rate** can increase usage by five to ten percent.

Figure 10-3



Low-income advocates frequently focus on rate design issues in rate cases. Most low-income consumers have significantly below-average usage, and an inclining block rate design will keep their bills lower.⁵⁶ Some low-income consumers, however, particularly those who have large extended families or living in older, inefficient housing, may have higher than average usage. Most low-income advocates favor addressing these needs with efficiency programs and with low-income assistance programs (discussed in Chapter 21).

In most states, the customer charge is set to recover customer-specific costs, such as metering, meter reading, and payment processing. In other states and some rural electric cooperative utilities, higher charges are established that recover portions of the distribution system investment and maintenance. For any given revenue requirement for residential consumers, a higher customer charge implies a lower per-unit usage charge, which favors large-usage consumers and leads to higher consumption levels.⁵⁷

56 National Consumer Law Center. (2015). *Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm. US Region: NY*. Retrieved from http://www.nclc.org/images/pdf/energy_utility_telecom/rate_design/NY-FINAL2.pdf

57 The inverse relationship between price and demand, referred to generally as *elasticity of demand*, is well established in theory and practice. It describes the percentage change in demand response to a given percentage change in prices. Estimates of these precise values can vary widely. Short-run elasticity estimates for electricity, however, will include timeframes for which the capital stock of appliances and end-use devices change. Estimates of long-term elasticity then are typically higher. A detailed analysis of elasticity is contained in *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*. See: <http://www.raonline.org/document/download/id/6516>.

Figure 10-4

| Illustrative Residential Time-of-Use Rates | | | |
|--|-----------|---------------|----------------|
| | Flat Rate | Mild TOU Rate | Steep TOU Rate |
| Customer Charge | \$5.00 | \$5.00 | \$5.00 |
| Nights/Weekends | \$0.10 | \$0.07 | \$0.05 |
| Mornings/Evenings | \$0.10 | \$0.10 | \$0.15 |
| Afternoon Peak | \$0.10 | \$0.13 | \$0.25 |

Time-of-use (TOU) pricing is becoming more common for residential consumers, particularly those who have high usage. This sets a lower rate for nights and weekends, which are off-peak times when the utility system has available capacity, and higher rates during the peak periods, when additional usage can force the utility to rely on peaking power plants not needed at other times, and also to incur higher line losses.

In general, residential TOU rates are voluntary, whereas larger commercial and industrial customers may face mandatory TOU rates. The proper design of a TOU rate will depend on the specific circumstances of a utility, the nature of its resource mix, and the shape of its load through the day and through the seasons. Even if the cost differentiation is not great enough to motivate consumers to alter their usage patterns, a TOU rate can still be appropriate to ensure that all consumers pay an appropriate amount for the power they use: consumers who have primarily **off-peak** usage cost less to serve, and arguably should pay lower bills. The expected deployment of advanced meters and so-called smart grid devices may eventually result in greater use of TOU rates, including mandatory TOU rates for residential customers.

Rates not only serve to recover costs, but also send a price signal to customers. TOU rates are intended to not only reflect that costs are higher during some times, but also to influence customers to reduce **on-peak** usage in an effort to reduce their bills. Mandatory TOU rates raise concerns for some low-income consumer advocates in this regard. For example, reducing on-peak usage can be accomplished through investments in energy efficiency that low-income customers may not be able to afford. In addition, low-income customers who have multiple jobs may not be able to shift their usage away from peak pricing periods.

10.2. General Service Consumers

General service customers are businesses of any kind, including office, retail, and manufacturing enterprises. Some utilities group them into customer classes by their size (typically kW demand), others by their voltage level, and still others by whether they are commercial or industrial facilities. Rates for these commercial and industrial customers are generally more complex than residential rates. They normally include a **customer charge** that is higher than the one residential consumers pay, reflecting higher metering and billing costs, and other cost characteristics that make them more expensive to serve. The general service **energy charge** per kWh may be priced by blocks or be differentiated by season or by time of day. For larger energy users, there is also usually a **demand charge** based on the customer's highest demand during the month, whether it occurs at the time of the system peak or not. In more advanced rate designs, the demand charge may also be differentiated by season or by time of day, with higher demand charges applying during the system (coincident) peak demand period. Demand charges sometimes have a *ratchet* feature, which adjusts the customer's monthly demand charge on the basis of their maximum demand during a preceding period, usually either the previous summer or the previous 12 months.

Because the demand charge recovers some of the costs associated with power supply, transmission, and distribution facilities, the energy charge for businesses that pay one is typically lower than that for residential or small-business consumers. This does not necessarily mean their overall cost per kWh is lower. In Figure 10-5, the average total revenue contribution for commercial usage, including the demand and energy charges, will be about \$0.10/kWh, roughly the same as in the residential example cited earlier. As a general matter, however, the rate structure does give the customer an incentive to moderate its highest demands on the utility, thereby reducing the demand charge portion of the bill and lowering its average total cost per kWh.

Figure 10-5

| Illustrative General Service Flat and TOU Rates | | | |
|---|-----------|---------------|----------------|
| | Flat Rate | Mild TOU Rate | Steep TOU Rate |
| Customer Charge | \$20.00 | \$20.00 | \$20.00 |
| Demand Charge/kW | \$10.00 | \$10.00 | \$10.00 |
| Energy Charge | | | |
| Nights/Weekends | \$0.07 | \$0.05 | \$0.04 |
| Mornings/Evenings | \$0.07 | \$0.07 | \$0.08 |
| Afternoon Peak | \$0.07 | \$0.10 | \$0.15 |

10.3. Residential Demand Charges

Some utilities have implemented optional residential rate designs that include demand charges, similar to the format of commercial customer rate design. If the demand charge is limited to the peak hours and applied to all usage within those hours, it can approximate a TOU rate and affect peak demand significantly. If it is applied to a customer's highest one-hour (or sometimes less) usage within an hour, it has the effect of shifting costs from customers who have relatively stable usage (large homes) to those who have more intermittent usage (such as apartments). This approach has been suggested by some rate analysts as a means to recover additional revenue from customers who have rooftop solar systems who receive fewer kWh from the grid.

Where customers do not have access to timely information about their energy usage, demand charges raise a fairness concern. The argument is that unless a customer can track their demand level in real time, demand charges are somewhat ineffective as a price signal that customers can use to modify their behavior.

Many European utilities require residential consumers to subscribe to a maximum level of demand, controlled by circuit breakers. The “demand charge” for these utilities is typically a very small portion of the bill, covering only the cost of the final **line transformer** and service connection.

10.4. Bundled vs. Unbundled Service

Most vertically integrated utilities only provide *bundled* service, or power supply plus distribution. In restructured states, most utilities provide only distribution service—which may include non-bypassable riders (discussed earlier) that the commission deems should be paid by everyone, while also offering an optional last-resort or **default service** for power supply.

In some states that generally have vertically integrated utilities, industrial customers have requested, and commissions have granted, optional distribution-only direct access rates. These allow the industrial user to purchase its power in the wholesale market directly from competitive suppliers, and to pay the utility only for delivering that power.

In many states, large industrial customers also enjoy the right to negotiate rates with the utility on a confidential basis. Utilities may also offer a variety of discounts and incentives to very large customers in an effort to encourage their greater use of energy and to encourage their remaining as customers of the utility. These rates are often justified as a way of encouraging economic development, and to ensure a large base of sales over which to distribute fixed costs.

10.5. Rate Design and Carbon Emissions

Rate design can influence customer usage, and when power is consumed, it influences what power plants are needed to produce that power. Inclining block rates will result in lower usage, and thus lower emissions. High fixed charges result in lower per-kWh rates, and will result in increased consumption and thus higher emissions. The impact of time-varying rates is less predictable. Depending on the mix of resources available, shifting usage from on-peak periods to off-peak periods may either increase emissions (if coal is the incremental off-peak fuel) or decrease emissions (if high-efficiency natural gas or renewable resources are the incremental off-peak resource).⁵⁸

10.6. Advanced Metering and Pricing

Utilities are introducing **advanced metering infrastructure** (AMI), consisting of smart meters to measure usage and meter data management systems to make the data useful. These systems allow them to measure usage in very short intervals by time of day and to communicate information to and from the customer. AMI is used not only for measuring usage, but also for peak load management and for implementing reliability improvements such as property transformer sizing, and for energy efficiency measures such as **conservation voltage regulation** (CVR). AMI enables utilities to better measure and predict consumer behavior, but the significant costs of new systems require regulatory scrutiny.

Advanced meters enable utilities to more easily establish more detailed rate designs by more accurately matching costs to usage. Smart meters can record customer usage by the minute, and can communicate back to the utility without a meter reader needing to travel from building to building. These smart meters have become quite inexpensive and will likely be the norm in the future, even for residential consumers.⁵⁹ There are important cost allocation issues relating to smart grid investments discussed in Chapter 9.

Some advanced rates are simple, with TOU blocks as discussed earlier, whereas others are more complex, targeting specific short periods of time when usage pushes up against system capacity. Rates that change in response to changes in market prices for power are generically known as **dynamic pricing**.

One form of dynamic pricing provides *real-time rates*, in which the amount that customers pay for energy changes every hour, or at least several times

58 See: Pace University. (2015). *Carbon Tuning New York's Electricity System*. Retrieved from <http://energy.pace.edu/publications/carbon-tuning-new-yorks-electricity-system>

59 There is controversy over whether utilities should replace all existing meters with smart meters and commissions are addressing the issue. However, smart meters have become the norm when installing meters on new buildings or replacing worn-out meters, even though all of their features may not be used for many years.

a day, in response to changes in wholesale market prices. The customer only knows a few hours, or a day in advance, what the rate for the next time period will be. These are typically restricted to very large industrial customers, but have been tested for smaller customers in a few utilities.

Another approach to dynamic pricing is designed to encourage consumers to cut back usage, during limited periods, when asked to do so by the utility. These are often called **critical period pricing** rates, and they take many forms but are usually an add-on to a TOU rate. They increase sharply when the utility experiences so much demand for power that its facilities are stretched thin.

The customer is notified of critical periods, typically a day ahead, but sometimes only a short time before the prices spike up. Customers who can cut back on short notice can help the system avoid the high costs of peaking power plants, additional transmission and distribution capacity, and the high line losses that occur during peak periods. In theory, when these consumers are given sharply higher prices during critical periods but slightly lower rates the rest of the time, both the customer and the system can save money when customers change their usage based on price signals. Those that cannot cut back during critical periods pay rates that reflect the high cost of power during that period. Unlike **real-time pricing**, this approach usually sets the rates for the extreme periods in advance—but only invokes those rates when the system is under stress and prices in the wholesale power market spike.

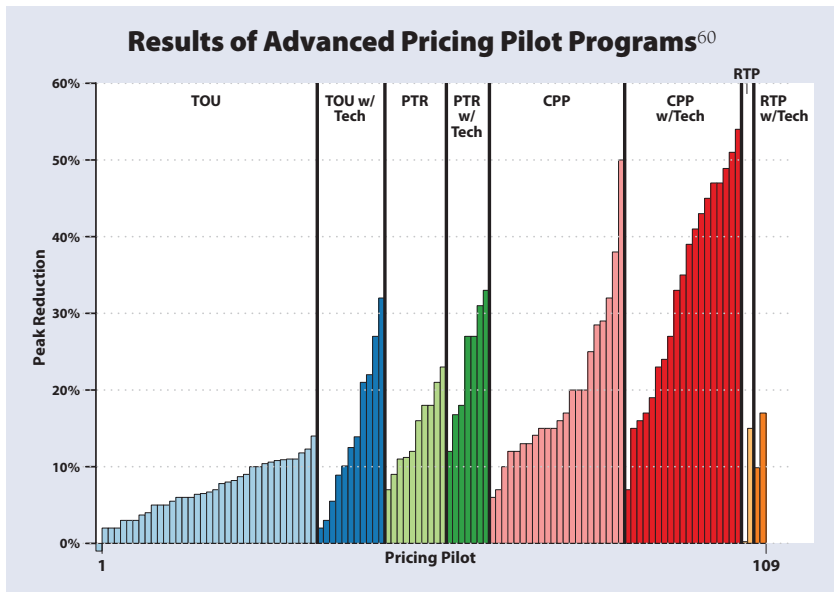
A variant is called a **peak-time rebate**. In this design, the customer is given a discount if load is reduced at the critical peak time. Rebate structures may be seen as less punitive for customers who have no means for reducing their on-peak usage.

Most dynamic pricing rates are strictly voluntary: customers can choose to participate or to stay with a more traditional rate design. It is probable that

Figure 10-6

| Illustrative Critical Peak Period Rate Design | | | |
|--|------------------|----------------------|-----------------------|
| | Flat Rate | Mild Critical | Steep Critical |
| Customer charge | \$5.00 | \$5.00 | \$5.00 |
| Nights/weekends | \$0.10 | \$0.07 | \$0.05 |
| Mornings/evenings | \$0.10 | \$0.09 | \$0.10 |
| Afternoon peak | \$0.10 | \$0.12 | \$0.15 |
| Critical peak hours | | \$0.25 | \$0.75 |

Figure 10-7



over time, both larger residential consumers and business consumers will increasingly be served through default or mandatory TOU and/or dynamic pricing rates.

These types of pricing induce what is called **demand response**. Other forms of demand response include bill credits for utility control and direct **curtailment** of specific loads, including water heating and air conditioning. We discuss demand response in Chapter 16.

Evidence shows that customers can and will respond to advanced rates. Figure 10-7 shows the peak load reductions achieved in 109 different pilot programs examining time-varying and dynamic rate design. This presents a potential peak cost (and peaking capacity-cost) reduction option that may be lower cost than building new generation and transmission to serve an increasing peak load.

10.7. Rate Design and Renewable Resources

The rate design principles that have guided regulatory decisions for decades (e.g., those put forward by Bonbright) were established in an era when vertically integrated utilities satisfied almost all of their customers’ electrical needs and nearly all electricity flowed in only one direction: from

60 Faruqui, A., Hledik, R., & Palmer, J. (2012, July). *Time-Varying and Dynamic Rate Design*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/5131>

the utility to its customers. But this is no longer the case. Owing to rapid growth in solar PV deployment, hundreds of thousands of customers—soon to be millions—self-supply some of their energy needs and engage in bidirectional transactions with their utilities. These customers continue to use the utility grid at virtually all times to import or export electricity, depending at each moment on whether onsite generation is less than or greater than onsite electrical demand.

This evolution in the roles of customers and utilities poses new challenges for retail rate design. Traditional residential rate designs rely in large part on volumetric energy charges to recover most utility costs of service, including grid costs. Although grids were built to deliver energy, these costs do not vary significantly in the short run with volumetric energy sales. When residential customers produce energy onsite, they purchase less energy from their utility and also reduce congestion on the grid. The utility can generally avoid some of its costs of service, particularly costs associated with energy supply, but its costs for delivery service may not change immediately and may take some time to realize. The crucial question for utilities and regulators is whether the value these renewable resources bring to the system, including long-run energy, capacity, distribution system, and **non-energy benefits**, exceed or fall short of the revenue that is lost. The answer to this question has many dimensions and significant ramifications for infrastructure cost recovery. Many studies have found a net benefit and others show a net cost when customers produce electricity onsite; the conclusions reached are highly dependent on the questions asked, the time frame considered, and the assumptions made in the analyses.

10.7.1. Green Power

Many utilities offer customers the option to pay a premium rate for a premium power supply sourcing. The most common offering, generally known as a “green power” tariff, allows customers to pay a premium to support additional renewable resources being added to the utility portfolio in an amount equal to the customer demand for premium power. Although the electrons do not flow directly to these customers, the addition of renewable resources displaces conventional generation, and has the same net effect on the system portfolio, emissions, and other environmental and economic impacts.

Green power or green pricing options raise issues regarding claims and consumer protection for customers precisely because electron flow cannot be traced through the electricity system. The Federal Trade Commission addresses these issues in its “Green Guides,” adopted under 16 CFR part 260 in the Code of Federal Regulations.⁶¹

61 See: https://www.ftc.gov/sites/default/files/documents/federal_register_notices/guides-use-environmental-marketing-claims-green-guides/greenguidesfrn.pdf

10.7.2. Infrastructure Cost Recovery

At low levels of distributed renewable energy deployment (e.g., less than five percent of distribution system load), infrastructure costs are largely unchanged from what they otherwise would be. This is currently the situation in most of the United States, but it is expected to change as solar output exceeds total load on a given **substation**. At this level of solar saturation, significant changes to distribution systems (such as the installation of additional voltage regulators) may be needed, and those changes will entail new costs. Improvements in distribution system technology and solar system equipment may reduce or eliminate some of these impacts and resulting costs. For example, “smart” inverter technology, controlled water heaters, and other options can provide voltage and frequency regulation services.⁶²

Regardless of whether the utility’s distribution system costs increase, growth in distributed renewable energy deployment can lead to infrastructure cost recovery issues if the utility’s projected revenues decrease by more than its cost of service. Utilities in such circumstances will have to raise their volumetric energy charges (which disproportionately would impact customers without onsite generation) or redesign their rates in the short run. Many utilities and some regulators have proposed or implemented changes to rate designs for customers who have DG in order to avoid raising **energy charges** to other customers. In addition, future test year approaches and more frequent rate cases may help mitigate the impacts of growth in the number of customer-generators.

The growth in **customer-sited generation**, smart metering, demand response, and other distribution level technologies raises a number of issues for the traditional utility model premised on one-way electricity flow from central station plants, and on customers who were largely passive consumers and “ratepayers.” Many states are addressing these issues in “utility of the future” proceedings addressing the industry transformation that is underway. For example, New York has initiated a proceeding called “REV” for “Reforming the Energy Vision.”⁶³

10.7.3. Net Metering

Net energy metering (NEM), or **net metering** for short, is a rate that charges customers who have onsite generation only for the “net” consumption, measured by subtracting the power supplied to the grid from the amount delivered to the customer by the utility. The concept behind

62 Hledik, R., & Lazar, J. (2016). *Distribution Pricing with Distributed Energy Resources*. Lawrence Berkeley National Laboratory.

63 See: <https://www.ny.gov/programs/reforming-energy-vision-rev#top>

NEM is that a customer who self-generates more than they consume in some hours, and exports power to the grid at those times, should be compensated for the power exported to the grid at the same price as power they purchase from the grid. Generally NEM tariffs provide that the customer who has net excess generation during any billing period will be compensated at the retail rate for electricity, and the customer receives credit for such generation on a future bill. NEM is strictly speaking a crediting from production and not a contract for sale. Customers on a NEM rate are therefore not in the business of generating electricity for sale, but are understood to be generating electricity for their own use, even if there are incidental exports of electricity to the utility system.

Many utilities have been critical of such provisions in NEM tariffs, because crediting at the retail rate, in their view, overcompensates the customer, and the decline in the customer's overall usage unfairly effectively transfers fixed system costs to other customers. The alternative view, voiced by solar advocates, is that the new, clean solar power received by the utility is more valuable than standard grid power. This issue has been debated in almost every state that has a NEM policy.

One of the more common proposals to address this issue, which has been adopted in some states already, is to reduce the compensation for net excess generation to something less than the full retail rate. Another common proposal is to retain full retail rate NEM for energy charges, but impose monthly demand charges or other special charges on customers who self-generate that are not imposed on other customers. The argument for this latter approach is that customers who self-generate through DG still need the benefits of the grid but are avoiding payment for their share of the fixed costs attributable to those benefits in volumetric electricity prices. As discussed earlier, the conclusions reached are highly dependent on the questions asked, the time frame considered, and the assumptions made in the analyses.

10.7.4. Value of Solar Tariffs

To address infrastructure cost recovery issues, some jurisdictions have recently turned to a new tariff design, the **value of solar tariff** (VOST), as an alternative to the NEM tariff. A VOST offers customers a predetermined credit rate for each kWh of solar generation their systems produce for the duration of the rate. The price is based on a comprehensive assessment by the utility or its regulators of the value of solar generation to the utility and society. This value of solar analysis is a cataloguing of all the costs avoided or imposed by solar generation sited at the distribution end of the electric system.

The VOST resembles a NEM tariff in that it is applied not through payments to the customer but rather through a bill credit mechanism. These are dollar credits rather than kWh credits. VOST is thus a net billing

tariff and not a NEM tariff. The dollar value of all consumed electricity (or sometimes all energy received from the grid) is calculated at the normal applicable retail rate. The dollar value of generated energy (or sometimes energy not consumed onsite and exported to the grid) is calculated using the VOST as determined through an administrative process. The customer is billed or credited based on the net of these two values. Credits are rolled over onto the next bill. The net-billing aspect is important in that it (arguably) keeps the utility–customer transaction squarely within the domain of retail (rather than wholesale) rate regulation.

Because the value of solar in any given utility territory could be more than or less than the customer’s retail rate, a VOST could in theory be more lucrative or less lucrative to generating customers than a NEM tariff. For Austin, Texas, a low-use residential customer gets a credit for each kWh that exceeds the retail price, whereas a large-use customer pays a higher price for incremental electricity use than the VOST provides as a credit.

Figure 10-8

| Austin TX Energy Residential Value of Solar Tariff (May 29, 2016) | | |
|--|---------------|---------------|
| Cost Element | Summer | Winter |
| Customer charge | \$10.00/month | \$10.00/month |
| 0 to 500 kWh | \$0.087 | \$0.072 |
| 501 to 1,000 kWh | \$0.124 | \$0.110 |
| 1,001 to 1,500 kWh | \$0.145 | \$0.126 |
| 1,501 to 2,500 kWh | \$0.164 | \$0.138 |
| Over 2,500 kWh | \$0.168 | \$0.150 |
| Solar production (all kWh) | (\$0.107) | (\$0.107) |

Source: <http://austinenergy.com/>

10.8. Summary on Rate Design

The form of electric rates affects consumers in many ways. It can increase or decrease total consumption and cause shifts of usage into or out of particular hours. Used effectively, good rate design can provide consumers with predictable pricing and reasonable bills, and help minimize long-run system costs by signaling to customers when their investments would be superior to utility investments. The most appropriate rate design will vary by utility and by region, depending on what changes are desirable and cost-effective.

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11. Other Elements of Basic Regulation

There are other elements of the regulatory process that are sometimes very important. We discuss a few of these here, but other issues arise on a geographic or temporal basis.

11.1. Service Policies and Standards

All the utility's rates, policies, and standards can be subject to change by the regulator during a rate case or an issue-specific docket. A variety of issues may be raised by the utility or by intervenors, including the line extension policy for new construction, the disconnection/reconnection policy and charges for consumers who do not pay their bills on time, the rules for low-income energy assistance programs, interconnection standards for customers with onsite generation, and the design of energy efficiency programs. Many of these are discussed in the sections that follow.

Issues such as these may be raised by utilities when they file their initial evidence in rate proceedings, or may often be introduced by intervenors during the proceeding. The commission will sometimes agree to resolve issues raised by intervenors, or may rule on them outside of the scope of the rate case. In the latter situation, if the issues are important, many commissions will initiate a separate proceeding to resolve them.

11.2. Single-Issue Ratemaking

Utilities often seek regulatory approval for isolated changes in costs, such as infrastructure replacement, smart grid investments, and distribution system “hardening” for storm resistance. These are examples of *single-issue ratemaking*. If the regulator evaluates only a subset of cost categories, other cost centers (which may be declining) are not examined. In a general rate case, both increasing and decreasing costs are considered, and only when the “net” impact over time is a need for higher revenues is a rate increase approved.

Some forms of single-issue ratemaking may be appropriate, but regulators and consumer advocates are generally wary to consider costs that are rising in isolation. This is the problem sometimes called “piecemeal” ratemaking. For example, a distribution system upgrade to enhance reliability, although quite possibly a beneficial investment, would be expected to be accompanied by

lower maintenance costs as fewer outages would occur, and with lower line losses, which reduce power supply costs. Similarly, smart grid investments can bring lower costs owing to improved outage identification and prevention, lower line losses, lower billing costs, and lower peak demand.

11.2.1. Issue-Specific Filings

There are a variety of other types of issue-specific filings that do not increase rates or revenues to the utility. Some are as simple as changing a tax rate when a local government adopts a new tax schedule; some would make additional services available to consumers, without changing service to other consumers. Others request accounting orders to clarify or change the accounting treatment of certain costs, so the utility can proceed with confidence about the process of cost recovery until the next rate case. The list of possibilities for issue-specific filings is nearly infinite. The key regulatory issue is to be aware of whether a single-issue filing fails to consider relevant cost decreases that may occur if the filing is approved that should be considered at the same time.

11.2.2. Tariff Riders

Often when single-issue filings are submitted and approved, the resulting price increases or decreases are reflected in a tariff rider to separately track the specific costs. Tariff riders may be an appropriate way to track costs, but the changes should be reflected in an adjusted effective rate on the customer bill, not separately stated. This keeps rates and bills more understandable. Bill simplification is addressed in Chapter 14.

11.3. Multi-Utility Investigations

Regulators sometimes convene multi-utility investigations, such as the relationship between natural gas and electric utilities, or between energy utilities and water or wastewater utilities. For example, a water conservation program that installs water-efficient appliances or fixtures will also have an impact on energy use for heating and pumping water, and on the costs for wastewater treatment, including the energy used in treating wastewater. Sometimes these can only be fully investigated by convening all of the relevant utilities and interest groups.

11.4. Joint State or State/Federal Investigations

On rare occasions, one state commission will team up with regulators from adjacent states to review issues related to multi-state utilities or the potential for investment by a utility in one state that will benefit consumers in multiple states. This approach is often used for conducting audits of multi-state utilities to ensure accurate characterization of financial conditions at a single

point in time. There are also Joint State Boards convened by FERC to review interstate cost allocation issues.

11.5. Generic Investigations

Occasionally a regulator will launch a generic investigation into an issue of regulatory importance. These typically involve multiple utilities, in an attempt to determine if a different type of regulation is appropriate. Examples include a generic investigation into rate design approaches, a decision of whether to modify energy efficiency programs, or consideration of decoupling or incentive regulation (see Chapters 12 and 19). Investigations like these typically have no immediate impact on the revenue requirement or rate level for any individual utility; instead they explore policy changes that may be implemented in future rate proceedings and can result in substantive rules or other expressions of commission policy.

12. Drawbacks of Traditional Regulation and Some Possible Fixes

The system of traditional regulation described in Chapters 8 through 10 sets a revenue requirement based on a calculated rate base, an estimated rate of return requirement, and carefully examined operating expenses and taxes. In the United States during the 20th century, this structure oversaw and facilitated the development of the world's most reliable and reasonably priced electric system. Even so, it has some drawbacks. This chapter identifies some of the more important ones and the responses to them.

In other sectors of the economy, competition is widely believed to produce powerful incentives for cost minimization by producers, ultimately leading to lower prices for consumers. Critics of traditional regulation often charge that the natural-monopoly characteristics of the utility industry, coupled with regulation that in effect provides companies with cost plus a fair rate of return, eliminates or reduces these efficiency incentives and leads to higher costs for consumers.

12.1. Cost-Plus Regulation

Cost-plus regulation was adopted as an effective way to regulate monopoly utilities. That is, by allowing only prudently incurred costs associated with used and useful investments and expenses, the regulator addresses the revenue requirement to arrive at just and reasonable rates. Because there was, by definition, no competitive service provider against which to benchmark prices, price control regulation was not appropriate. And competition itself was seen as inefficient because it would lead to unnecessary duplication of infrastructure.

One of the most common critiques of traditional cost-plus regulation, named the **Averch-Johnson effect** after the authors of an article explaining this effect, suggests that utilities will spend too much on capital investments because their allowed return is a function of their investment.⁶⁴ Utilities have been accused of spending more on power plants, transmission, and distribution facilities than would be expected by a cost-minimizing,

64 Averch, H., & Johnson, L. (1962). Behavior of the Firm Under Regulatory Constraint. *American Economic Review* 52:1052-1069.

profit-maximizing enterprise. According to this theory of excessive capital investment, a company that is allowed what is seen by management as a return on its investment in excess of its actual cost of capital will tend to over-invest, or *gold-plate* its system.

In addition to high investment levels, traditional utility regulation may also encourage excessive operating expenses, because its cost-plus structure means that all approved costs will be passed through to consumers. Although commissions do review operating expenses to determine if they are reasonable before approving them, they may not have the staff adequate for them to really examine them in detail in every rate case.

Also, the higher the operating expenses were in the test year, the more the company is allowed to earn in the year after the rate case is resolved, so there is an incentive to “load up” expenses in any year expected to serve as a basis for a future rate case.

As discussed in Chapter 8, the allowed revenue requirement is based on the allowed operating expenses, plus the product of the net rate base and rate of return. However, the utility does still have some incentive to reduce expenses. Once the rates are set, they stay in place until changed, regardless of whether the operating expenses are the same, higher, or lower than in the test year; so the utility earns more if it incurs lower costs.

The cost-plus regulatory model also sends long-term signals to the utility regarding investments and sales.

12.1.1. Regulation and Innovation

Where the utility return is tied to the level of investment, and that investment is subject to regulatory scrutiny for whether it is used and useful, the result may be a fear of innovation on the part of utilities. Creative change involves risk, and if the only potential “upside” is cost recovery, while the potential “downside” is a disallowance, utilities may be hesitant to innovate. This leaves regulators with a difficult role to encourage innovation while protecting consumers from imprudent expenditures. Various forms of performance-based regulation attempt to address this challenge.

12.1.2. The Throughput Incentive

As awareness of the need to constrain energy use has grown in recent years, the incentives that traditional regulation provides for utilities to increase sales have been of particular concern. The Averch-Johnson effect posits that the utility increases profits by increasing its rate base, and that additional investments in the rate base are justified by and require additional sales—so there is also an incentive to increase usage.

But even without the Averch-Johnson effect, utilities still have an incentive to increase sales in the short run. If a utility can serve increased usage with

existing facilities, and if current fuel and operating costs (the costs to produce and deliver another kWh with the existing power plants and distribution facilities) are lower than the retail rates, increased sales will increase profits in the short run. This is known as the **throughput incentive**, because utilities have a profit incentive to increase sales. This is particularly problematic where utilities have a “fully reconciled” fuel and purchased power adjustment mechanism, because those mean that any increase in sales results in an increase in profits.⁶⁵ The throughput incentive may be an important reason that utilities resist the implementation of energy efficiency programs that would achieve long-run savings for consumers but reduce near-term utility sales, resulting in lower short-run profits. Chapter 19 addresses the throughput incentive and approaches to overcome this bias toward higher sales.

12.1.3. Regulatory Lag

Regulatory lag refers to the time between the period when costs change for a utility, and the point when the regulatory commission recognizes these changes by raising or lowering the utility’s rates to consumers. Regulatory lag is generally cited by utilities as a problem with regulation, because rates do not keep up with rising costs. Likewise, some consumer advocates favor regulatory lag for its tendency to keep costs from hitting rates. As a result, utilities have requested—and some commissions have granted—mechanisms to deal with changes between rate cases, such as **fuel adjustment clauses** (FACs—these are discussed in some detail in Chapter 14). However, as the throughput problem implies, regulatory lag can also work in the utility’s favor: if costs decline or sales increase between rate cases, the utility’s profits may rise with no change in rates required. Although commissions generally have the authority to order rate decreases, this is unusual, and the “lag” between when the excess profits begin and when the commission takes action is typically longer than the lag when costs increase and utilities seek higher rates.

Expense reconciliation mechanisms, like a fuel-cost adjustment charge, can mitigate the impacts of regulatory lag for the most volatile expenses incurred by the utility, but create other concerns, as discussed in Chapter 14.

12.2. Responses

Many regulatory concepts have evolved to address these problems. Some require specific legislative authorization; some have been done within the commission’s general regulatory authority. Several are outlined here.

65 Moskowitz, D. (1989, November). *Profits and Progress Through Least-Cost Planning*. Prepared for the National Association of Regulatory Utility Commissioners. Retrieved from http://www.raponline.org/docs/RAP_Moskovitz_LeastCostPlanningProfitAndProgress_1989_11.pdf

12.2.1. Decoupling or “Revenue Regulation”

Decoupling is a slight but meaningful variation on traditional regulation, designed to ensure that utilities recover allowed amounts of revenue independent of their sales volumes. The general goal is to remove a disincentive for utilities to embrace energy efficiency or other measures that reduce consumer usage levels. Decoupling begins with a general rate case, in which a revenue requirement is determined and rates are established in the traditional way. Thereafter, rates are adjusted periodically to ensure that the utility is actually collecting the allowed amount of revenue, even if sales have varied from the assumptions used when the previous general rate case was decided. If sales decline below the level assumed, rates increase slightly, and vice versa. Sometimes the allowed revenue is changed over time to reflect defined factors, such as growth in the number of consumers served. Decoupling, also known as **revenue regulation**, is discussed in greater detail in Chapter 19.

12.2.2. Performance-Based or “Price-Cap” Regulation

Performance-based regulation (PBR) ties growth in utility revenues or rates to a metric other than costs, providing the utility with opportunities to earn greater profits by constraining costs rather than increasing sales. For example, a five-year rate plan might allow a utility to increase rates at one percent below the rate of inflation each year. In other schemes, a commission-determined adjustment, sometimes called a *Z-Factor*, may be included to capture predictable changes in costs other than inflation and productivity. Then if the utility invests in expensive new facilities, its costs will grow faster than its revenues, so it has an incentive to constrain expenditures. In the absence of a decoupling component to the PBR plan, this approach is often referred to as *price-cap regulation*.

Commissions have learned to establish strict service quality standards when approving multiyear PBR mechanisms, because experience showed that some utilities took actions to improve earnings at the expense of reliability and customer service quality (see Chapter 22 on Service Quality Assurance).

Figure 12-1

Comparison of Traditional Regulation and Price-Cap PBR

Traditional Regulation

Rate Base x Rate of Return + Operating Expenses = Revenue Requirement/ Sales = Rates

Performance-Based Regulation

Rates in Period 1 + Inflation - Productivity ± Z-factor = Rates in Period 2

12.2.3. Incentives for Energy Efficiency or Other Preferred Actions

Some commissions have established incentive mechanisms to reward utilities that take specific actions or achieve specific goals. These innovations are often seen as application of the concept that regulators are creating circumstances like those the utility would face if it operated in a competitive market. For example, a business that helps customers manage electric bills would be rewarded in the marketplace with higher profits. These innovations may, for example, include a bonus to the rate of return for exceeding commission-established goals for energy efficiency programs, or penalties for failure to maintain commission-established goals for reliability. In most cases, the incentives are tied to the value of the goals the commission is seeking to achieve, and are large enough to be meaningful to the utility, but not so large as to create significant rate impacts for consumers. Many more utility performance metrics than are currently in use are available, and a higher percentage of the utility's allowed return could be derived from performance. Appropriate incentives or rewards for effective performance are increasingly recognized as sound regulatory practices, for which consumers are well served.

12.2.4. Competitive Power Supply Procurement

Several commissions have required regulated utilities to conduct open competitive bidding when new power supply resources are needed. The utility is often allowed to bid in the process, but if a non-utility provider offers an equivalent product at a lower cost, the utility is obligated to buy the lower-cost power. This ensures the utility cannot gold-plate its power facilities, because a competitive provider will be able to underbid it. A transparent process is needed to verify results. Some commissions have required that renewable resources be acquired by contract, but still allow utilities to invest in conventional power plants.

12.2.5. Restructuring

Other states have gone further, by requiring utilities to divest their power plants and requiring that all power for consumers be provided by other suppliers. This eliminates any profit in the power-supply segment of the business, as well as possible problems with gold-plating and cost-plus regulation in that segment (although it may cause other problems). Restructuring, however, creates other challenges for regulators. Most important of these is finding an equitable and economical way to provide a default power-supply service for consumers who do not choose a competitive supplier (unless, as in Texas and the United Kingdom, no default service is offered and customers are required to choose a power supplier). Regulators in

retail competition states are also alert for the distribution utility relationship with generation owning affiliates in overseeing default service procurement or competitive power supply offerings to consumers who may confuse the competitive affiliate with the regulated distribution utility.

The growth in regional wholesale power supply markets and the recent decline in natural gas prices has had a similar effect. In these markets, all generation owners, including generation affiliates of distribution utilities, sell their generation into the market, and the affiliated distribution utility may buy it back to supply default service, all at market rates, as a result of federal regulatory changes. For an increasing number of utilities, this means that generation owned by utility holding companies cannot fully cover its costs at prevailing market rates, leading to many power plant retirements that would not necessarily have happened under old-style regulation. In some states, utilities have petitioned state regulators to withdraw from competitive wholesale markets or to approve cost-recovery surcharges to keep high-cost power plants operating.

Power plants still owned by the distribution utility and subject to cost of service regulation that are rendered uncompetitive owing to market impacts may be argued to no longer be “used and useful” in providing electric service, triggering another kind of regulatory review.

12.2.6. Prudence and Used-and-Useful Reviews

When an expensive new power plant or major transmission facility enters service, regulators often perform a prudence review to determine if the facility was chosen and built in an economic fashion. Often consultants who have power-sector construction experience are retained to perform the review. If the planning or construction is deemed imprudent, the commission may disallow a portion of the investment, refusing to include it in the rate base.

A similar review may determine if the plant is actually used and useful in the provision of service to customers; if not, excess generating capacity or other plant costs may be excluded from the rate base.

In some states, a pre-approval process for major investments is used, so that the commission reviews major projects for cost, consistency with resource planning goals, and other factors before construction begins. This is becoming increasingly important as older power plants face significant environmental retrofit costs (see Chapter 20 on environmental issues).

12.2.7. Integrated Resource Planning

IRP, which is discussed in more detail in Chapter 15, requires the utility to develop a publicly available, long-range plan for the best way to meet consumer needs over time, usually anywhere from 10 to 20 years. Typically the commission reviews the plan, orders modifications if necessary, and

approves it as the guidance document for future utility investment and operations decisions. In most states, the plan itself and particular investment decisions are not “approved” per se, but are found to be a reasonable guide to future actions. Actions recommended in the plan are also generally not preapproved by regulators, and as conditions shift, the utility is expected to adapt its plans and decision-making.

12.2.8. Integrated Distribution System Planning

The modern electric grid includes not only centralized power plants, but also distributed generation, demand response, and price-sensitive usage, all of which can work together to provide quality energy service at reasonable cost. The traditional utility function of electricity distribution is being rapidly transformed into a complex net load management function involving thousands of points of power supply and millions of points of power delivery. Fully integrating this fast-developing mosaic of resources requires a distribution system capable of measuring and responding to information from both system operators and consumers. This integration also offers an opportunity to reduce distribution system costs, for example, by meeting short-duration peak demands with demand response (reducing usage) rather than supply-side measures that require increasing generation, transmission, and distribution capacity. The science of considering all of the elements of a modern distribution system interacting with both suppliers and consumers is called **integrated distribution system planning**. Chapter 16 addresses this topic.

For more information:

Blackmon, G. (1994). *Incentive Regulation and the Regulation of Incentives*. New York: Springer US.

Lazar, J. (2014, May). *Performance-Based Regulation for EU Distribution System Operators*. Brussels: The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/7332>

13. Transmission and Transmission Regulation

Most power in the grid flows from large generating plants into the transmission system, then to the distribution systems of individual utilities, and ultimately to individual homes and businesses.⁶⁶ The transmission system allows utilities to use and even optimize diverse resources—such as wind, coal, nuclear, or geothermal energy—even if they are located far from consumers.

Wind plants need to be constructed where the wind is strongest and most consistent; building coal plants near the mines and shipping the electricity over long-distance transmission lines may be preferable to hauling the coal by railroad to a power plant near users. Utilities also often sell power to one another, and that power must be moved from one system to another. In some cases, utilities may have long-term contracts for power produced more than 1,000 miles away.

The US Constitution assigns to Congress the power to regulate interstate commerce. Congress has implemented that power by, among other things, enacting the Federal Power Act. Under that Act, FERC has authority over the pricing for most transmission services. Public power entities such as the New York Power Authority, Arizona's Salt River Project, North Carolina's Santee Cooper, and the Los Angeles Department of Water and Power are not under FERC jurisdiction. Federal power marketing authorities, such as the BPA, the Western Area Power Administration, and the TVA are also self-governing and are subject to FERC review of their actions, rather than direct regulation by FERC. Finally, most of Texas and all of Hawaii and Alaska are outside FERC jurisdiction because they are not connected, or not tightly connected, to the interstate transmission grid. However, the entities not subject to direct regulation by FERC generally consider FERC policy and adhere to similar standards.

This chapter briefly describes the function of the transmission system and how transmission pricing is regulated.

66 An increasing amount of power is produced by distributed generation in small power plants at homes and businesses. This power may be used where it is produced, or transferred onto the distribution system and used by another customer nearby.

13.1. Transmission System Basics

The transmission network moves power at high voltages over long distances. Generally the term **transmission** applies to lines that carry power at extra high voltages of 115 kilovolts (kV) (115,000 volts) and greater through big wires, mostly on steel towers. *Sub-transmission* consists of lines operating at 34.5 to 115 kV. These sub-transmission lines may be classified as transmission, subject to federal regulation, or as distribution lines subject to state regulation; this depends functionally on whether they move bulk power from power plants to different utilities, or move power around within a single utility system to serve retail consumers. Lines carrying 34.5 kV volts or less are almost always considered distribution lines, subject to state regulation. In the United States, there are standard voltage levels to allow the manufacture of transformers and other equipment.

Power is actually generated at lower voltages and *stepped up* through transformers before it enters the transmission network. This is because higher voltage lines can carry more power and will experience lower line losses. Sometimes power is transformed up a second time, to be loaded onto very high voltage lines—345,000, 500,000, or 765,000 volts—for long-distance transmission and to strengthen the transmission system against contingencies.

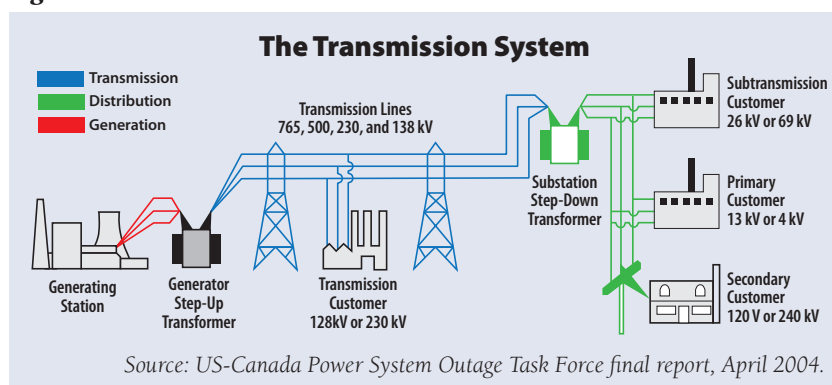
In a few areas, power is also converted from **alternating current** (AC) to **direct current** (DC) for transmission purposes, because DC is more efficient for moving power very long distances. DC interconnections can also be used to move power between the eastern United States, the western United States, and Texas; these three grids (Quebec is also a separate grid) are not synchronized with each other, so AC cannot be transferred directly between them. At about ten locations along the boundary between the three US interconnections, there are facilities where power is converted from AC to DC and back to AC so it can be moved from one grid to another.

Very large industrial customers sometimes receive power at transmission voltages, directly from the transmission system. Most customers, however, take power at lower voltages. The power must be stepped down through transformers before customers take delivery at sub-transmission voltages, primary voltages, or **secondary voltages**, as shown in Figure 13-1.

If the transmission system is robust, with a certain amount of redundancy built in, it can withstand the failure of its most critical lines or other components. In fact, a set of standards promulgated by NERC and enforced by FERC holds transmission owners and operators accountable for being prepared for contingencies. This is critical to reliability: if one grid element fails, a heavily loaded power line or a large generation source, the effect can cascade through a system without protection systems in place. This planning approach is sometimes shorthanded as “N-1.”

On a few occasions, entire regions of the country have been plunged

Figure 13-1



into darkness because of the failure of one segment of transmission and a cascade of resulting failures. For this reason, great attention has been given to maintaining transmission reserves, to provide spare capacity when something goes wrong, and to real-time monitoring of transmission reliability and funding needed transmission system upgrades. Some control areas (see Chapter 3) have invested to be able to “island” their systems from neighboring areas in the event of a major transmission failure or other contingency. Small portions of the grid, designed to be capable of operating in an islanded mode with local generation and storage resources, are called **microgrids**.

13.2. Transmission Ownership and Siting

Most transmission facilities in the United States are owned by individual utilities, including the federal power-marketing agencies. Some are jointly owned by multi-utility groups. In some cases, transmission lines are owned by independent entities other than utilities, which receive payment from all users of the lines—like toll roads for electricity.

Within the US system of franchised utilities, operating under cost-plus regulation based on used and useful investments serving specific geographic areas, each individual utility is likely to invest in transmission based solely on the needs of its own service territory. It may perceive no incentive to invest to protect reliability for adjacent areas. Moreover, the state regulatory framework may provide no legal basis for its regulator to require such additional investments, or to compel public power utilities or cooperative utilities to cooperate. Many regional power pools and other arrangements have evolved over the history of the industry to build transmission networks and manage them cooperatively, but these have become more formalized since the Energy Policy Act of 1992 and FERC Order 888. Reliability problems have persisted

in some locations where there is more demand for transmission capacity than existing facilities provide, and this has led FERC to support the creation of RTOs and ISOs that do consider multi-utility reliability issues. FERC order 890 and order 1000 require RTOs, ISOs, and other regional electricity planning entities to coordinate regional transmission planning.

New transmission is built to address a reliability issue, an economic issue, a public policy issue, or some combination of the three. The need for new transmission is identified in a transmission planning process in which reliability, economic, and policy requirements are considered in a ten-year look forward. The transmission planning process considers load growth, planned generation, and other resources and policy requirements like RPS that require new renewable generation. New transmission requires a project investor to fund the project as well as a benefits and costs assessment that determines how the costs of the new transmission are allocated among customers and recovered in rates.

New transmission lines require long rights of way across the property of multiple owners, the land-use jurisdictions of multiple local governments, Native American tribes, and states. Lines cross city, county, and state boundaries, traverse public and private lands, and affect the allowable land use in their immediate vicinity. For this reason, the transmission-siting approval process remains one of the most complex aspects of providing adequate transmission facilities. A mixture of local, state, and federal government agencies holds jurisdiction over who can build what, where they can build it, when they can build it, and who pays for it. Proceedings can become quite contentious, as well. The critical threshold issue is “need”—whether the transmission line is necessary to serve customers and maintain reliability in light of other technological, routing, and load management options available.

In some states, authority for approving new transmission lines has been vested in a single agency to expedite the evaluation process and to reflect the general value to all of a network system. In other areas, separate approval must be obtained from each city and county through which a line passes, plus each governmental territory the lines pass through.

FERC has limited authority to override local authorities to provide for construction of lines that address the national interest, as deemed by a periodic US Department of Energy assessment.⁶⁷ In some parts of the United States, the lack of new transmission lines has hampered the development of renewable energy resources, because current transmission lines do not necessarily reach areas that are most advantageous to renewable energy. This

67 Energy Policy Act of 2005, Title XII, Subtitle B, § 1221.

has prompted identification of “renewable energy zones,” with transmission authorized into these regions before the generation is committed and built. Also, transmission pricing has generally evolved to serve baseload coal and nuclear projects; that pricing structure creates challenges for intermittent power sources like wind and solar that FERC is evaluating.

13.3. Transmission Regulation

FERC regulates the pricing of wholesale transmission transactions, both what is charged to utilities and what is charged to individual industrial consumers who buy power directly at transmission voltages. Transmission pricing takes several forms, including *postage stamp pricing* (one rate regardless of distance), *license plate pricing* (a price within specified zones), and *point-to-point distance-sensitive pricing*. Transmission rates are also sometimes *pancaked*—meaning that as power moves across multiple lines, from one transmission owner to another, each owner gets paid for the use of its facilities. These layers can add up to substantially more than they would if a single owner controlled all of the facilities. One reason for creating regional power pools, RTOs, and ISOs (see Chapter 3) is to develop systems of joint pricing for transmission services and to minimize pancaking. Pancaking creates an economic advantage and the potential for exercise of market power by generators located near load centers and is generally seen as a challenge to wholesale generation markets. Nodal transmission systems seek to overcome this problem while also allowing transmission prices to reflect congestion on the transmission system, which is a key pricing signal for transmission investment.

When utilities deliver power to industrial consumers at transmission voltages under direct access or restructuring, the charges they apply for transmission service must be the rates approved by FERC. They may also charge for any additional services they provide, at rates regulated by the state commission.

The procedure, evidence, and timing in a FERC rate-setting case are similar to a state utility general rate case. There is currently no consumer advocate for the FERC process,⁶⁷ however, so the parties do not routinely include representatives of the public unless one or more state commissions or state consumer advocates intervene.

In addition to several acts of Congress, including the Energy Policy Acts of 1992 and 2005, five key decisions by FERC guide current transmission regulation and planning.

Order 888 (1996) detailed how transmission owners may charge for

67 PURPA provided for an Office of Public Participation for FERC when enacted in 1978, but the position has never been funded or activated.

use of their lines, and the terms under which they must give others access to them. Order 888 also required utilities to separate their transmission and generation businesses, and to file open access transmission rates through which they provide nondiscriminatory transmission service. FERC hoped that this separation would make it impossible for a utility's transmission business to give its own power-generating plants preferential access to the company's lines. FERC also provided for the creation of separate transmission-owning companies, generally known as transcos, that could build lines where local utilities would not.

Order 889 (1996) created an *open access same-time information system* (OASIS), through which transmission owners could post the available capacity on their lines, so all companies that wanted to use the system to ship power could all track the available capacity.

Order 2000 (1999) encouraged transmission-owning utilities to form RTOs. FERC did not require utilities to join RTOs; instead, it asked that the RTOs meet minimum conditions, such as having an independent board of directors. FERC gave these regional organizations the task of developing regional transmission plans and pricing structures that would promote competition in wholesale power markets, establishing the transmission system as a highway distribution system for that wholesale commerce.

Order 890 (2007) directed transmission providers to conduct local and regional transmission planning in a coordinated, open and transparent manner.

Order 1000 (2011) requires transmission providers to participate in Order 890-compliant planning processes that include a broad representation of stakeholders. Order 1000 also requires that all planning processes reflect state and federal public policy mandates in planning assumptions including but not limited to renewable energy and energy efficiency goals. FERC mandates that non-transmission alternatives be considered in transmission planning. Finally, FERC required that all regional plans have a cost allocation methodology in place.

13.4. Non-Transmission Alternatives

When new transmission lines are considered, there are a variety of non-transmission alternatives that can be examined as alternatives. For example, geographically targeted energy efficiency measures may be able to provide load relief in an area, avoiding the need for new transmission capacity. Local generation, either utility-scale or customer-sited resources, can also be an available transmission alternative. The evaluation of non-transmission alternatives is necessarily complex, because of the multiple benefits to power supply, transmission, and distribution that may result.

This chapter began by stating that “most power in the grid flows from

large generating plants into the transmission system, then to the distribution system of individual utilities, and ultimately to individual homes and businesses.” A growing percentage of power is flowing in the other direction, from customers. Most of that is absorbed by the distribution system (other customers), while a small and growing fraction is exceeding local uses and flowing through transformers into the transmission system. Protection schemes are available to protect equipment, and utilities must implement these at some cost. A future edition of this guide will likely address this condition of the transmission system in greater detail.

For more information:

Brown, M., & Sedano, R. (2004). *A Transmission Primer for Government Officials*. Retrieved from http://www.raonline.org/docs/RAP_Brown_TransmissionPrimer_2004_04_20.pdf

FERC, *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States*.

National Renewable Energy Laboratory. *Transmission Grid Integration: Transmission Planning and Analysis*. Retrieved from http://www.nrel.gov/electricity/transmission/transmission_planning.html

Neme, C., & Sedano, R. (2012). *US Experience with Efficiency as a Transmission and Distribution System Resource*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raonline.org/document/download/id/4765>

US Department of Energy, *A Primer on Electric Utilities, Deregulation, and Restructuring of US Electricity Markets*.

14. Tariff Adjustment Clauses, Riders, and Deferrals

This chapter describes a number of mechanisms that allow for cost recovery outside of the general rate case process. Those include **adjustment clauses** for various expenses, energy efficiency funding mechanisms, and tracking mechanisms.

Adjustment clauses are used to change utility rates between general rate cases, to account for changes in specific costs, or for changes in sales. These rate changes typically require little scrutiny by the regulator, because the adjustments are governed by formulas and rules that were themselves fully evaluated. Adjustment clauses deal with specific factors that have effects on costs and the company's bottom line and are beyond the control of utility management—for example, factors of production, changes in demand, and changes in the broader economy. In each case, the commission has determined that recovery should be allowed (or considered) outside of a general rate case.⁶⁹ Periodic audits check to see if the mechanisms are being properly implemented, and to ensure that unintended cross-subsidies between customer groups do not develop.

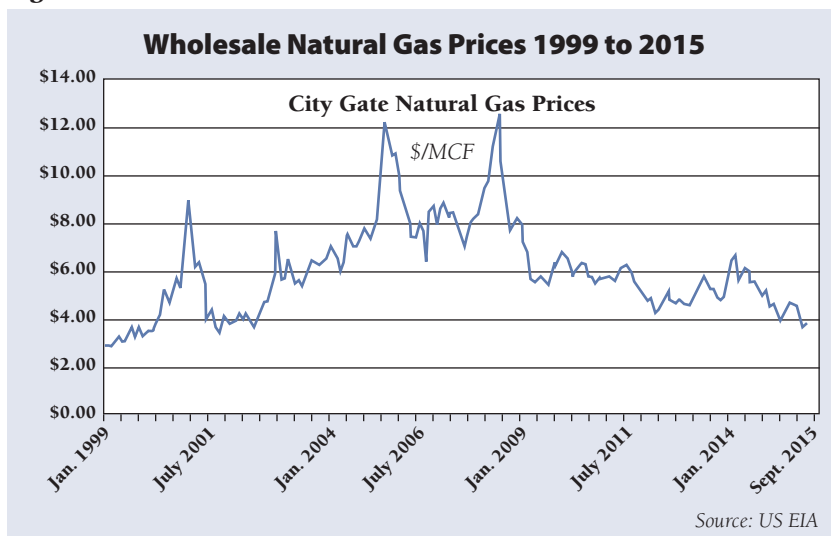
The most common and most important of these mechanisms are *purchased gas adjustment* (PGA) mechanisms and FACs. However, there are many different types of adjustment mechanisms and tariff riders in place. In recent years, such mechanisms have been used to collect environmental equipment investment costs, other regulatory compliance costs, power plant investment and upgrade costs, and other costs—all outside of or between major rate cases (see section 14.5).

14.1. Gas Utility-Purchased Gas Adjustment Mechanisms

Most natural gas utilities own their distribution networks, but no gas wells. They purchase gas from producers and pay pipeline companies to deliver that gas to their systems. As Figure 14-1 shows, the price of gas can

69 Not all regulators and policymakers accept this argument. The contrary position holds that it is not, by itself, direct control over a cost or revenue item that matters, but rather whether the risks it imposes can be managed through steps such as alternative investments, changes in operations, financial hedges, or changes in consumer behavior. It concludes that regulation should be based on which party—the utility or the consumer—is better fitted to manage and bear the risk in question.

Figure 14-1



change greatly on short notice, and the gas utility has little ability to influence the price of gas (except by signing multiyear contracts with fixed or indexed prices).

The cost of purchased gas typically makes up about one half of a gas utility's total costs, and a sudden surge in wholesale gas prices can severely affect cash flow, earnings, and the ability to pay dividends. These problems can arise in the short term, even while the gas utility is fully entitled to recover its costs of purchased gas over the long term.

Most PGA mechanisms pass changes in purchased gas prices and transmission costs directly on to consumers. Some also provide for flow-through of the changes in the cost of gas—like liquefied natural gas or gas from underground storage reservoirs—used during extreme weather to meet peak demand, because these are often owned by entities separate from the utility.

Some PGA mechanisms adjust rates annually, but most allow for more frequent adjustments, particularly if costs change quickly.

14.2. Electric Utility Fuel Adjustment Mechanisms

Electric utilities in the United States generate most of their power with coal and natural gas, and both of these fuels are subject to significant **price volatility**. Utilities also buy power from other utilities and from non-utility generators including renewable generators, and those prices are also sometimes subject to change in response to market forces. During the oil embargoes of 1973 to 1974 and 1978 to 1979, when fuel costs shot up

suddenly, most electric utilities sought and received approval for their first FACs.

These have since evolved into more complex mechanisms. Some track only fuel cost, some include short-term purchased power, some include all purchased power, and some include all power costs (including the investment costs in utility-owned power plants). Some allow for dollar-for-dollar flow-through of actual costs, whereas others have specific formulae that require the utility to bear some risk of cost variations between general rate cases.

For most utilities, the FAC creates much more variation in consumer prices than the changes approved in general rate cases do, because these costs are large and volatile. Many utilities manage these costs by buying their fuel on long-term contracts, by buying financial contracts known as “hedgies” or “collars” to mitigate price volatility effects, or even buying the coal mines and gas wells that provide the fuel.

FACs have been criticized for removing the incentive that utilities have to manage, stabilize, and contain their fuel costs. One regulatory concern often expressed is that if utilities can recover the actual cost of fuel, they have little incentive to maintain power plants to achieve peak fuel efficiency. Fuel and purchased power adjustment mechanisms have also been extensively criticized because they assure that any increase in sales volumes brings an increase in earnings, even if the short-run incremental cost of power exceeds the retail rate.⁷⁰

14.3. Benefit Charges for Energy Efficiency

Most electric and gas utilities provide energy efficiency services to their consumers. In recent years, the amount invested has become more significant for many utilities, and they have sought approval for adjustment mechanisms to recover these costs. The most common form, a *system benefit charge* (SBC), applies to all consumers using the distribution system.

An SBC is typically structured so that utilities collect a surcharge, often calculated as a percentage of revenues, on all sales of electricity or natural gas. This goes into a separate, dedicated account, and the utility makes expenditures from that to support consumer efficiency programs. If the programs are very successful and the funds run out, the utility may seek an increase to the SBC at any time. See Chapter 17 on Energy Efficiency Programs for more information.

A variation on the energy efficiency system benefit charge is one that applies for additional purposes, such as demand response costs or clean energy.

70 Moskowitz, 1989.

A *clean energy surcharge* can be used to recover the premium a utility pays for renewable power that is not covered in its base rates; this is particularly applicable for utilities without a FAC or other cost recovery mechanism.

14.4. Renewable Energy Cost and Benefit Trackers

As renewable energy supplies have become an increasingly important part of utility resource portfolios, some regulators have allowed separate cost accounting for these costs. Because wind and solar power are variable but the costs for the facilities providing them are not, there is uncertainty about the cost per unit or the annual costs. In addition, because there are tax benefits associated with renewable energy that begin when the plants begin service and expire after a defined period, some regulators have included tracking mechanisms for the tax benefits, so that the utility does not have to seek rate adjustments when new plants enter service or earlier units exhaust their tax benefits.

14.5. Infrastructure and Other “Trackers”

An assortment of other adjustment mechanisms and **trackers** are used to ensure that some cost, revenue, tax, or other element of utility rates is recovered, and that changes in those cost elements need not await a general rate case to be recognized. One kind of tracker is a surcharge to recover local government taxes that may not be uniform throughout the utility service territory, and which can be changed without approval of the utility regulator. A surcharge can also collect money for extraordinary costs that are time-limited, such as storm damage or the refund of a one-time tax benefit. Others adjust for such things as nuclear decommissioning costs, new investment in infrastructure between rate cases, and refunds of specific amounts of money ordered by the commission.

All these adjustments are implemented separately from a general rate case, are associated with specific cost accounts, and are typically noted separately on the consumer bill. Consumer advocates are often critical of these single-issue trackers, asserting that they mostly follow increasing costs, whereas other costs that may be decreasing over time are only addressed in periodic general rate cases, creating a “heads I win, tails you lose” situation for the utility. Consumer advocates also point to cases in which these trackers proliferate such that consumers do not see any of them clearly as they examine their bill. They argue that instead of conducting single-issue rate making, commissions should consider all costs, including those that decline over time owing to productivity, technological innovation, and other causes.

Multiple regulatory proceedings related to individual trackers can be difficult and expensive for non-utility parties, and raise issues of fair access to regulatory processes, especially as regulatory agencies and consumer counsel

offices face budget limitations. Utilities are typically allowed to pass their rate case expenses through to customers in rates.

14.6. Weather-Only Normalization

A weather-only normalization mechanism adjusts the utility rates periodically so that weather variations do not affect utility profits. This is particularly relevant for natural gas utilities, for which weather can dramatically affect sales and profits. Utilities use sophisticated computer models in each rate case to calculate how their sales vary with weather, and commissions are familiar with their methods. Weather-only mechanisms use the same model to calculate how much sales varied from the level assumed in the rate case. Weather-only normalization is a form of limited decoupling, which is described in Chapter 19.

14.7. State and Local Taxes

Many states and cities impose revenue-based taxes on utility operations. Because these tax rates are outside the control of the utility and may be changed between rate proceedings, these are generally handled through adjustment mechanisms so that a change in the tax rate is immediately flowed through to consumers.

14.8. Adjustment Mechanisms and Bill Simplification

If every adjustment mechanism were separately stated on customer bills, the bills would soon look more like a hospital bill, unintelligible to all but the most highly trained experts. For this reason, regulators often require that utilities “roll up” the adjustments into understandable terms that customers can understand. The most important information to consumers is the amount by which their bill will rise or fall in response to changes in consumption, so incorporating the tracking changes and adjustment mechanisms into the unit prices displayed on the bill is helpful.

14.9. Deferred Accounting and Accounting Orders

Under normal accounting principles, expenses such as fuel costs incurred in one period must be deducted from income in the same period. In order for a utility to keep an expense on its books for future recovery, the commission must approve an *accounting order*. This provides some assurance that future recovery is likely, and that therefore a deviation from normal accounting is appropriate. Similarly, under normal accounting rules, once an asset is placed in service, the utility must begin recording depreciation expense each month, accounting for the asset being used up.

Although all the tracking mechanisms described previously generally do

Figure 14-2

| Example of an Electric Bill That Lists All Adjustments to a Customer's Bill | | | |
|---|-------------|--------------|-----------------|
| Your Usage: 1,266 kWh | | | |
| Base Rate | Rate | Usage | Amount |
| Customer Charge | \$5.00 | 1 | \$5.00 |
| First 500 kWh | \$0.05000 | 500 | \$25.00 |
| Next 500 kWh | \$0.10000 | 500 | \$50.00 |
| Over 1,000 kWh | \$0.15000 | 266 | \$39.90 |
| Fuel Adjustment Charge | \$0.01230 | 1,266 | \$15.57 |
| Infrastructure Tracker | \$0.00234 | 1,266 | \$2.96 |
| Decoupling Adjustment | \$(0.00057) | 1,266 | \$(0.72) |
| Conservation Program Charge | \$0.00123 | 1,266 | \$1.56 |
| Nuclear Decommissioning | \$0.00037 | 1,266 | \$0.47 |
| Subtotal: | | | \$139.74 |
| State Tax | 5% | | \$6.99 |
| City Tax | 6% | | \$8.80 |
| Total Due | | | \$155.53 |
| The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design. | | | |
| Base Rate | Rate | Usage | Amount |
| Customer Charge | \$5.56500 | 1 | \$ 5.56 |
| First 500 kWh | \$0.07309 | 500 | \$ 36.55 |
| Next 500 kWh | \$0.12874 | 500 | \$ 64.37 |
| Over 1,000 kWh | \$0.18439 | 266 | \$ 49.05 |
| Total Due | | | \$155.53 |

have accounting orders to support them, accounting orders are often used without any immediate change in rates. For example, a utility may have a new power plant come into service before a rate case is decided, and the commission may allow the utility to accrue a return on that plant investment, for future recovery in rates that take effect at the end of the rate case. In essence, the accrual of interest during construction may be allowed to continue after completion until new rates are implemented.

15. Integrated Resource Planning/ Least-Cost Planning

IRP, or *least-cost planning*, evolved in the 1980s, in the wake of the significant costs of a variety of expensive new power plants—some finished and some abandoned during construction—that caused sharp electric-rate increases in many parts of the United States.

IRP was intended to create a process by which many different energy resource options—on both the supply and demand side—could be evaluated in an integrated fashion to arrive at the plan with the least overall cost. Looking ahead through a planning process in which all stakeholders could participate and in which all lifecycle costs could be evaluated was intended to expose large, unproductive, or uneconomic investments and reveal the most economic path forward.

Of course, all utilities do some sort of long-range planning, but not all these plans are developed with the involvement of the regulator and other stakeholders. Not all regulators require IRPs to be prepared. Of those that do, not all have a process to formally approve them, and others accept them without ruling. Some utilities prepare them without any regulatory requirement to do so.

The idea of looking ahead in planning has the benefit of putting small-scale and large-scale solutions on a more comparable planning footing. For example, when the need for new electric supply reaches the level to justify a new power plant or a new transmission line, small-scale efficiency or generation options may appear inadequate to meet the need. However, small-scale resources can be added over time in a way to displace or defer more expensive investments. Technological and economic improvements in smaller-scale “**distributed energy resources**” (DER) has led to a resurgence in attention to *localized* integrated resource planning (LIRP) or **integrated distribution planning** (IDP) in some jurisdictions (see Chapter 16).

This chapter discusses such methods of planning for future power supply, transmission, and distribution needs, including a provision for public involvement and commission oversight. Some planning mechanisms are mandated and described by state statute, some are functions of the commission’s regulatory authority, and some are a function of both.

15.1. What is an IRP?

IRPs examine the forecasted needs on the electric system and evaluate alternative means for meeting identified needs. Over the last decade the needs for electricity have been affected by much slower load growth and much greater use of variable energy resources like solar and wind to meet needs. In the coming decade, EVs are expected to affect the net needs as well. As a result, the net needs on the system are no longer driven by load growth, rather they are driven by a number of factors, and the net needs are no longer simply energy and capacity needs but also include the need for certain **ancillary services** and flexible resources.⁷¹ These documents look at a wide range of options to meet future needs, including continued operation of existing power plants, building new power plants, or buying power from non-utility generators. They may also consider non-generation alternatives, such as investing in energy efficiency programs, demand response, promoting efficient new construction, reducing transmission and distribution system line losses, encouraging customer-owned generation, and any other available, reliable, and cost-effective means of meeting customer needs. These emerging DERs are shifting the focus to a two-way relationship in which consumer needs are met and consumer resources are used to meet utility system needs.

Some IRPs also consider local and regional transmission requirements, setting forth a plan for future upgrades to existing lines and/or construction of new lines. Because different utilities have different seasonal usage patterns and can sell power to one another, additional transmission interconnections may eliminate the need for construction of new power plants.

The goal of an IRP is to identify the best or least-cost resource mix for the utility and its consumers that ensures reliable service for all. *Least-cost* in this case means lowest total cost over the long-run planning horizon, given the risks faced. The best resource mix is typically the one that remains cost-effective across a wide range of futures and sensitivity cases—the most *robust* alternative—and that also fully takes into account the adverse environmental consequences associated with its execution. States with explicit public policies that encompass environmental goals like carbon reduction and **renewable portfolio standards** seek to achieve a least-cost outcome within these constraints.

Most IRPs do not consider distribution-plant improvements that can reduce line losses and avoid the need for generation; but increasingly, utilities are including consideration of nontraditional alternatives to power supply and transmission needs. Chapter 16 addresses integrated distribution system planning, which considers the impact of customer-sited resources, storage, and demand response in optimizing distribution system costs and performance.

71 In some cases, utilities may be facing predicted load declines, rather than increases. Even so, the principles of integrated resource planning remain the same.

15.2. How Does an IRP Guide the Utility and the Regulator?

An IRP compares multiple alternatives and examines the costs, reliability, public policy compliance, and environmental impacts of each. Achieving the prescribed level of reliability is usually a prerequisite for all alternatives examined. Achieving mandatory requirements is also a prerequisite for all alternatives for those states that have mandatory public policy goals like renewable portfolio standards. The alternatives examined typically differ in cost and in environmental and reliability performance (beyond mandated requirements), so trade-offs among and between these performance outcomes can be evaluated by the utility, stakeholders, and the regulator. The utility uses the results of the IRP to decide what types of resources to acquire, whether it is better to own power plants or buy power from others, and how to manage its programs to achieve the desired results. The regulator may use the IRP to determine what investments the utility may make, and it should use the IRP as one tool in evaluating the prudence of the utility's actions over time. However, simply including a proposed resource in an IRP (whether approved or merely accepted by the regulator) does not necessarily “make it prudent” or confer preapproval, nor does it excuse the utility from continuous re-examination of proposed projects in light of such factors as changing loads, changing costs, and emerging alternatives.

Roughly 30 states rely on IRPs, and the manner in which they do so varies. Some consider the IRP approval process to be preapproval of the investments that follow, but most still conduct project-specific prudence review before those investments are included in rates. The detailed and complex nature of an IRP often means that its success or failure depends critically on the commitment of utilities to the process and on the involvement of the commission and stakeholders.

The status of the final IRP varies greatly from state to state. Some states merely “acknowledge” the IRP document as meeting minimum requirements. Some states “accept” the IRP, and may provide guidance on direction based on the IRP. Other states actually formally “approve” the IRP and the resource decisions within the document. Often an IRP includes an “action plan” for the immediate future, and sometimes the action plan is subject to greater scrutiny and regulatory approval.

15.3. Participating in IRP Processes

Where the regulator requires an IRP, it often provides for the participation of stakeholders—consumers' groups, industries, environmental advocates, business groups, and others—in the planning or review process.

An IRP advisory group may be formed to review drafts, propose alternatives for evaluation, and report to the regulator when the finished

product is submitted for review. Sometimes stakeholders can intervene in the formal regulatory process; each state that requires IRPs has its own approach. The detailed and complex nature of the IRP can make it a challenging and resource-intensive vehicle for stakeholders. Some states appoint an “independent observer” or facilitator to represent the Commission in the IRP process.

Public hearings on the IRP are one opportunity for public involvement. In some states, this has been used by advocates to press for a change in direction of resource planning. This is viewed as more constructive than merely criticizing the inclusion of new resources in rates at the time of a general rate case.

Environmental regulators participating as stakeholders can also inform the IRP process. Any new power plant that receives approval from a utility regulator will also usually require environmental permits.

Environmental regulators may also want to ensure that the IRP assumptions are consistent with those used by air, land, and water regulatory agencies in their respective resource-planning efforts. The IRP can help environmental regulators assess, first, whether their existing standards are adequately protective in light of overall or likely resource impacts; second, the level, timing, and stringency of future air, land, and water standards; and third, the potential role of energy efficiency and customer-owned resources in helping to meet current and future environmental requirements.

Some regulators examine the proposed IRP in detail and may order changes. Others will conduct a more cursory review and only determine whether the document meets the minimum requirements of their law or rules.

15.4. Energy Portfolio Standards and Renewable Portfolio Standards

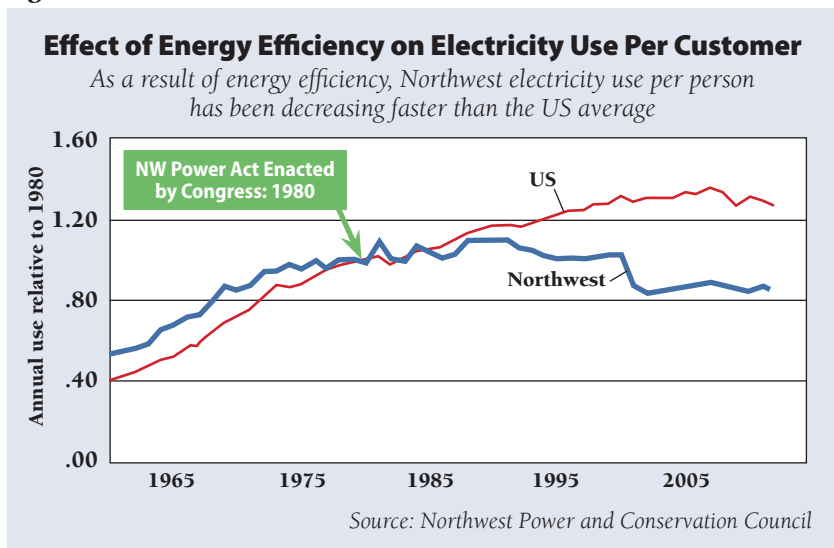
Most states have adopted specific resource portfolio standards for utilities. Most of these require each utility to meet a specific portion of its energy requirements with qualifying renewable resources; these are known as **renewable portfolio standards** (RPSs), which are discussed in Chapter 18. Several have required a specified mix of energy efficiency resources and renewable energy resources; these are known as **energy portfolio standards**, which are addressed in Chapter 17. A few, including California, Washington, and Minnesota, have adopted requirements for utilities to secure all cost-effective energy-efficiency resources. The IRP process is one way to ensure that the utility is undertaking the planning necessary to achieve the long-term goals set in the renewable and/or energy portfolio standards.

15.5. How an IRP Can Make a Difference

The most sophisticated IRP in the United States is probably the regional power plan prepared by the Northwest Power and Conservation Council. The Council is a four-state body (Washington, Oregon, Idaho, Montana), created by Congress in 1980 as part of a regional electric power act that expanded the authority of the BPA. The Council planning process is set out in federal law.

The First Power Plan, published in 1983, led to the termination of two partially completed nuclear power plants in which more than \$2 billion had been invested. Once lower-cost and lower-risk alternatives were identified, it became clear that continued preservation of the mothballed units was not economic. Energy efficiency investments in the region since 1978 have reduced regional loads by 5,800 average megawatts of energy, meeting half of regional demand growth. The annual savings are estimated at \$3.7 billion per year, and reduced CO₂ emissions by almost one-third. The region's electricity use per capita has declined significantly.

Figure 15-1



72 Pacific Northwest Electric Power Planning and Conservation Act, 16 USC 839.

73 Northwest Power and Conservation Council. See: <http://www.nwccouncil.org/energy/energy-efficiency/home/>. Note: the significant downward change in 2001 reflects closure of several large industrial facilities at the expiration of favorable pricing contracts.

The Seventh Power Plan, released in 2016, contains more than 5,000 pages of analysis and recommends that the Pacific Northwest take the following actions:

- Invest in 4,300 megawatts of energy efficiency;
- Invest in wind and geothermal resources as needed to meet state renewable portfolio standards;
- Plan for the possibility of some additional natural gas generation, particularly for peaking;
- Develop demand response resources to mitigate peaking needs and add flexibility; and
- Retire several existing coal plants.

The Council process is public, transparent, and technically very sophisticated. Although IRPs in other states may also be highly sophisticated, none currently come close to the detail, rigor, or transparency of that prepared by the Council.

For more information:

Moskovitz, *Profits and Progress Through Least-Cost Planning*.

Northwest Power and Conservation Council.(2016). *Seventh Northwest Power Plan*. Retrieved from <http://www.nwcouncil.org/energy/powerplan/7/home/>

16. Integrated Distribution System Planning

IDP, sometimes called **distribution resource planning** (DRP), is the task of planning to meet anticipated distribution system needs as consumers use proven and emerging DERs. IDP is an expansion of the IRP process to include optimizing investment in the distribution system, and taking into consideration the role that DERs may play in providing efficient, economical, and reliable service.

One important task of the IDP is to recognize the capabilities of DERs so that the potential of low cost DER portfolio solutions are considered. A second important task of the IDP is to determine how much investment is needed once one takes into account the DER portfolio effects. A third important task of IDP is to provide transparency to consumers and developers about where on a distribution system there is *headroom*, also known as *hosting capacity*, to accommodate more distributed generation, EVs, solar PV capacity, and other DERs, and where on the system there are opportunities to provide complementary DERs that increase headroom.

Utilities that provide distribution service have planned to serve expanding demand for as long as they have offered service, but evolving technologies and changing customer preferences are creating a need for more sophisticated distribution planning approaches.

Prior to the oil crises in the mid-1970s, a utility planner could safely assume that the utility's customers were passive in how they would interact with the utility, and planning could be done with demographics and a ruler.

The next generation of distribution planning evolution is more complex, because energy consumers are becoming energy producers as well as providers of services to the grid. Distributed generation, EVs, thermal storage, electric storage, advanced metering, advanced sensing, and electricity control technologies and advanced inverter technologies are making two-way flows on the system increasingly common and are creating an increasing array of opportunities for customers (or an aggregator) to use customer-sited resources actively to meet their own needs and to provide services to others.

Distribution utilities now face the challenge of responding to fundamental changes in the customer's interaction with the distribution system and maintaining reliability as two flows of energy and services emerge. One approach to maintaining reliability would be to over-build the distribution

system infrastructure so that the system can handle a wide range of customer behaviors. This approach is likely to be more expensive than necessary. Another approach is to seek to use the capabilities of DERs to maintain reliability without investing in infrastructure. This approach is likely to overlook the need for some essential system upgrades and may lead to reliability concerns. IDP seeks to combine both approaches in an economically efficient and reliable manner.

Effective IDP, like effective IRP, requires a characterization of system need, a characterization of resource potential, an identification of net need for new resources or capabilities, an inventory of available tools and technologies, and an assessment of the optimal investment necessary to meet emerging needs.

16.1. Emerging Challenge: Hosting Capacity

Assessing need on the distribution system requires that the distribution utility collect data that reflect consumption and production at different places (e.g., by substation feeder) and at different times (e.g., time of day, season of year). The amount of new resources that can be accommodated without incremental infrastructure investment is called the hosting capacity. The criteria used to establish the maximum hosting capacity are based on reliability metrics.

One can evaluate the hosting capacity of the distribution system as a whole or one may evaluate the hosting capacity on a particular feeder or circuit in the system. When a feeder has available DG hosting capacity, DG interconnection on that feeder can be fast. When a feeder has available EV hosting capacity, EV additions can be served quickly. At some level of penetration, additional distribution system investment, such as voltage regulators or smart inverters, may become necessary. When circuits reach a point at which they may be uploading through the substation to other circuits or through the station transformer to the transmission voltage level, additional sensors, controls, and protections may be needed. The IDP defines hosting capacity limits to facilitate expedited adoption of DG or EVs, but the IDP also assesses what actions can be taken to expand hosting capacity limits. Further complicating the process is the fact that DERs are becoming more technologically sophisticated all the time. Newer DER technologies, such as “smart” inverters used with distributed generators, can be integrated easily and may even be a source for grid ancillary services.

16.2. Expanding Hosting Capacity

As hosting capacity limits are approached, action may need to be taken to accommodate additional DG or EVs. The two options for expanding hosting capacity are adding complementary DER portfolios or investing in distribution system infrastructure. Examples of infrastructure investments

include upgrading distribution circuits to operate at higher voltages (re-conductoring), investing in transformers, voltage regulators, smart inverters, or substation upgrades that support increasing two-way flows. Examples of DER portfolio changes that can increase hosting capacity include adding local demand response, adding local thermal or electrical storage, adding energy efficiency to reshape the consumption profile on the circuit, or upgrading to inverters with advanced inverter capabilities.⁷⁴ Smart pricing and programs can induce customers to adopt DER portfolios or change their consumption patterns in ways that increase hosting capacity without incremental infrastructure investment.

The following sections describe the role that DERs can play in smoothing net load, supporting local system reliability, and providing distribution and grid services. Perhaps the most powerful resource is the electricity demand shaping driven by TOU tariff design (see Chapter 10 for a discussion of the local and system benefits of smart pricing).

16.3. Energy Efficiency

Energy efficiency programs targeted at loads in key hours can smooth load and reduce the need for capacity at the circuit, substation, and system levels. Load forecasters project that system loads and IDP will require forecasters to consider local distribution system loads as well. Energy efficiency programs all reduce energy consumption but they differ in how they affect the **load shape** that the **distribution system operator** and grid system operator must manage (see Chapter 17 for more discussion of energy efficiency program types and load profiles).

16.4. Demand Response

Demand response resources are **demand-side resources** that modify demand in response to physical signals or price signals. Examples of demand response to physical signals include cycling air conditioners, irrigation systems, smart appliances, and controlled water heaters. Examples of demand response to price signals include dynamic pricing programs, peak-time rebates, smart EV charging, and smart thermostat programs.

Utilities in vertically integrated states procure demand-response resources through programs or tariffs, and the resources are usually used solely to manage the load within that utility's own control area. In some restructured states, demand-response resources are mostly bid into wholesale markets, whereas in others the resources may be used mostly for managing the load

74 For a detailed discussion of the capabilities of advanced inverters, see: Electric Power Research Institute. (2014). *Common Functions for Smart Inverters, Version 3*. Retrieved from <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002233>

presented to the system operator by the **load-serving entity** (LSE) or utility.

Regardless of the market context, demand-response resources can be divided into:

- those resources that are primarily used to modify load in the day-ahead time frame;
- those that modify load on an as-needed basis with short notice; and
- those resources that can be called upon to provide real-time services, like frequency response service and **voltage support**.⁷⁵

Because it modifies the load at distinct points in the distribution system, demand-response resources can provide a range of services that may be helpful in increasing hosting capacity.⁷⁶ Mitigating system peak, or peak demand on a given feeder, can increase the EV hosting capacity on that system or feeder. Some demand response programs that have the capability to shift load (e.g., water heater control programs) can increase the DG hosting capacity on a system or feeder by adding load during those hours when DG is supplying energy and reducing load in other hours. Some demand-response programs (e.g., water heaters) can provide ancillary services like voltage support and frequency response. Smart electronics and improved communications are creating a new category of responsive appliance resources that can be used for various purposes.

Taken together, demand-response services, pricing, and energy efficiency can significantly affect hosting capacity by modifying the load on a day-ahead or real-time basis, and by providing system services that address the reliability limiting conditions that constrain hosting capacity.⁷⁷ That being said, there are still situations in which physical upgrades to the distribution system are necessary to address hosting capacity limits.

16.5. Local Generation

Local generation includes generation that is sited on the distribution side of the substation. It includes customer behind-the-meter systems but may also include generation that is not sited on a customer's property. PV DG is the most common form of local generation, but other sources like biodigesters, fuel cells, small wind systems, and small **combined heat and power** systems are also considered local generation for the purposes of this chapter.

75 California Independent System Operator (CAISO). (2013, December). *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources*. Retrieved from <https://www.aiso.com/Documents/DREERoadmap.pdf>

76 Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource*. Synapse Energy Economics, Inc., and The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/6597>

77 The second edition of "Teaching the 'Duck' to Fly" illustrates how demand-side resources can work together to affect load shape and provide services.

“Smart inverters” not only convert the DC power from PV systems to AC power for the grid, but can control the voltage and waveform of that power as needed to assure grid reliability. They can reduce or eliminate the need for additional utility investment in voltage regulators, capacitors, and other grid upgrades.

PV DG generation with advanced inverter capabilities may be controllable to some extent by the system operator. Therefore, installing advanced inverters will affect the hosting capacity of a feeder. PV DG can also affect the EV hosting capacity of a feeder. To the extent that charging on the feeder can be concentrated and controlled during daylight hours (e.g., a worksite where employees charge during work hours) adding PV DG can increase the EV hosting capacity of a feeder, or, conversely, adding EV load can increase PV hosting capacity.

Perhaps most interesting are the options available from combining DG with electricity storage, either through stationary electrical or thermal storage, or through an EV configured in a vehicle-to-grid (V2G) configuration.

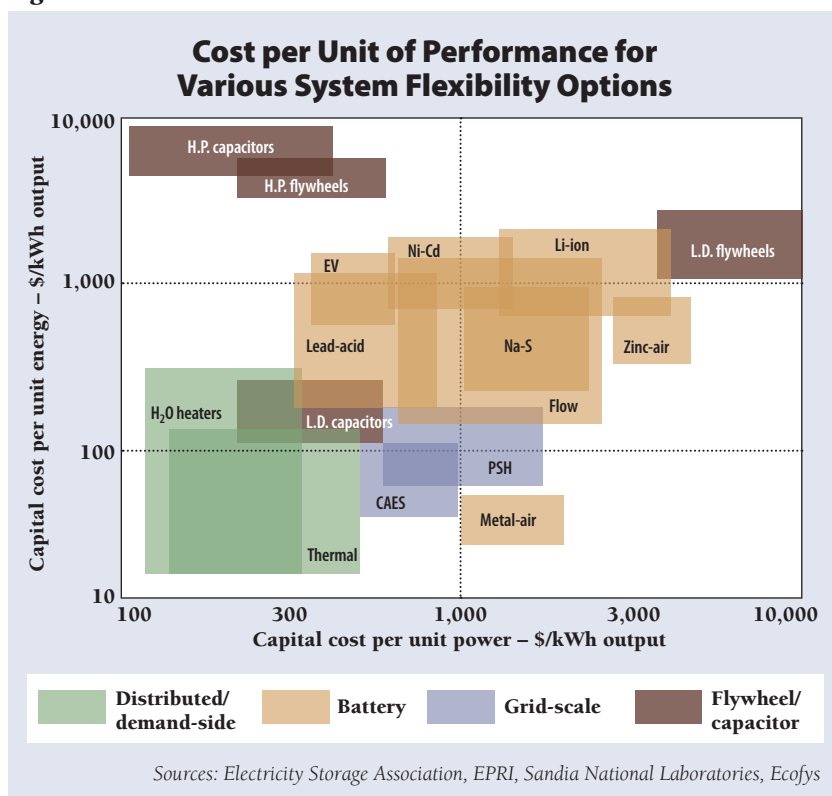
16.6. Storage

Storage is the quintessential “flexible resource.” Storage is usually thought of as being a battery, but not all storage is *electricity* storage. Thermal storage like electric water heaters, refrigerated warehouses, and commercial air conditioning systems with ice storage can also provide system flexibility services by shifting when they consume power, and these sources of storage tend to be much less expensive than current battery technologies. It is important to note that not all storage is in the form of batteries, and not all storage is expensive.

Electricity storage is becoming more cost-effective in places with high electricity costs or severe local reliability challenges. Electricity storage can also be an alternative to an expensive distribution system upgrade. A modest amount of storage (or demand response) in the right place does not look expensive when contrasted with the full price tag of the production, transmission, and distribution infrastructure upgrades necessary to otherwise address the local challenge.

Storage is most cost-effective if the storage serves multiple functions, such as production capacity cost avoidance, distribution capacity cost avoidance, ancillary services, and renewable energy integration. Storage is thus a valuable resource for addressing impending hosting capacity constraints. Storage also adds significantly to the ability to economically and effectively integrate larger quantities of DG and other DER to the system.

Figure 16-1



16.7. Role of the Utility Regulator

The utility regulator has several important roles to play in distribution system planning. First and foremost, as the primary representative of the public interest, the regulator should constantly seek options that provide reliable service at optimal cost. Because this may involve both utility actions and consumer actions, a close analysis of options is critical. The need for coordination of these roles may require an expansion of customer programs from the historical energy efficiency role to a broader perspective.

Pricing plays an important role as well: consumers will be more willing to invest in DERs that can provide grid services if there is an appropriate compensation framework. Because a portion of the benefits of DERs accrue to the power supply function, and a portion affect the distribution function, regulators in restructured states need to be particularly vigilant to ensure that cost-effective options are considered, and that the compensation framework bridges both the power supply and distribution benefit stream.

In some areas, adoption of grid interconnection codes and standards may be necessary to expand hosting capacity to enable an optimal mix of supply resources and DERs. Regulators have seldom taken on the task of managing these highly technical elements in the utility tariff, but change may be needed to achieve an optimal response.

For more information:

CAISO, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources*.

Hurley, Peterson, & Whited, *Demand Response as a Power System Resource*.

Lawrence Berkeley National Laboratory (LBNL), *Future Electric Utility Regulation Series*:

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De Martini, P., & Kristov, L. (2015, October). *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight* (Report No. 2). Berkeley, CA: LBNL. Retrieved from https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf

Lowry, M., & Woolf, T. (2016, January). *Performance-Based Regulation in a High Distributed Energy Resources Future* (Report No. 3). Berkeley, CA: LBNL. Retrieved from https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf

Hledik, R., & Lazar, J. (2016, May). *Distribution System Pricing With Distributed Energy Resources* (Report No. 4). Berkeley, CA: LBNL. Retrieved from <https://emp.lbl.gov/sites/all/files/feur-4-20160518.pdf>

Lazar, J. (2016, February). *Teaching the “Duck” to Fly—Second Edition*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/7956>

Lindl, T., Fox, K., Ellis, A., & Broderick, R. (2013). *Integrated Distribution Planning Concept Paper*. Interstate Renewable Energy Council and Sandia National Laboratories. Retrieved from <http://energy.sandia.gov/wp-content/gallery/uploads/Integrated-Distribution-Planning-May-2013.pdf>

Perez, R., Rábago, K., et al. (2016, September). Achieving Very High PV Penetration—The Need for an Effective Electricity Remuneration Framework and a Central Role for Grid Operator. *Energy Policy*, 96, 27-35. Retrieved from <http://www.sciencedirect.com/science/article/pii/S0301421516302452>

17. Energy Efficiency Programs

Energy efficiency is considered *cost-effective* when the net cost of installing and maintaining measures that improve the efficiency of energy usage is less than the total cost of building, maintaining, and operating the generation, transmission, and distribution facilities that would otherwise be needed to supply enough energy to achieve the same end-use over the same lifetime. There are also environmental costs of both energy supply and some energy efficiency measures, which can and should be considered in measuring cost-effectiveness. Other non-energy costs and benefits may also be considered.

Energy efficiency is a superior resource to meet consumer needs for many reasons. First, it is reliable: high-efficiency air conditioners and lighting systems don't break down in thousand-megawatt increments like power plants and transmission lines. Second, a kilowatt saved is worth more than a kilowatt supplied, because the utility system avoids transmission and distribution costs and line losses, plus it avoids the **reserve capacity** needed to assure reliable service. Third, there are many non-energy benefits associated with energy efficiency measures beyond those typically considered in benefit/cost evaluation. Last but not least, society avoids the pollution and other **externalities** caused by power production.

This chapter describes utility involvement in energy efficiency, and alternative methods to achieve high levels of energy efficiency in a local area.

17.1. Why Are Utility Commissions Involved?

It is not usually natural for a business to try to reduce the demand for its core commodity product—yet utilities may be uniquely qualified to play a role in improving the efficiency of energy usage. Indeed, utilities have never been solely in the business of selling electricity. They have relevant technical knowledge and they have a business relationship with all of the energy users in their service territory as a provider of “electric service.” Being “affected with the public interest,” utilities are in a unique position to lower the overall cost to society from electricity demand. At a minimum, utilities should be involved in energy efficiency planning, because the degree to which consumers invest in efficiency affects the extent to which utilities must invest in more and costly new power supply and distribution system capacity. Efficiency also affects the reliability of the grid. Regulators must be involved to ensure that the economic benefits of energy efficiency investment are achieved and to ensure that the

regulatory systems in place are adequate to allow timely cost-recovery, even when sales diminish or decline through the utility's own efforts.

Economic theory suggests that competition will produce an efficient allocation of goods and services if certain preconditions are met. These include the requirements that:

- goods be perfect substitutes for each other;
- all producers and consumers have perfect information;
- no producer or consumer is large enough to move the market;
- there is free entry and exit from the market; and
- capital is fungible and can be instantly redeployed.

None of these precepts holds true in the regulated energy field. In particular, consumers seldom have perfect information; and low-income households, small businesses, and others have limited or very limited access to capital. For many end-uses, therefore, we have what is known as market failure: customers will not “make the rational choice” on their own.

Regulators and policymakers have several tools to address market failures. Although some of this market failure can be addressed through better consumer information, by more accurate, forward-looking pricing of energy, financing assistance, or through strict codes and standards, evidence shows that those adaptations will not achieve all cost-effective energy efficiency. For this reason, most states have determined that there is a role for utilities in achieving what the market does not achieve—wide deployment of cost-effective energy efficiency measures.

Utilities usually invest in energy efficiency because their commission or state legislature requires them to draw on efficiency as the least expensive, most environmentally benign, most reliable, and most “local” energy resource available. Even without a commission mandate, utilities may have an increasing desire to use energy efficiency as a low-cost solution to the risk associated with large anticipated increases in generating costs, and in emissions costs (arising, for example, from putting a price on CO₂ emissions). When mandating energy efficiency, regulators set the parameters for an efficiency program or a portfolio of programs, determine who will operate the programs, establish the criteria by which programs will be evaluated, handle complaints if the program runs into problems, and determine the level and timing of the utility's cost recovery.

17.2. Non-Energy Benefits

The energy benefits of efficiency measures—reduced production, transmission, and distribution system costs—are generally well understood. But there are a wide variety of other benefits that need to be considered, quantified where possible, and incorporated into program design. These are called Non-Energy Benefits (NEBs) or Other Program Impacts (OPIs).

The benefits of energy efficiency fall into three broad categories:

Utility System Benefits. Generation, transmission, distribution, line losses, reserves, avoided RPS compliance costs, fuel cost risk, fuel supply risk, emissions compliance costs, reduced arrearages and collection costs.

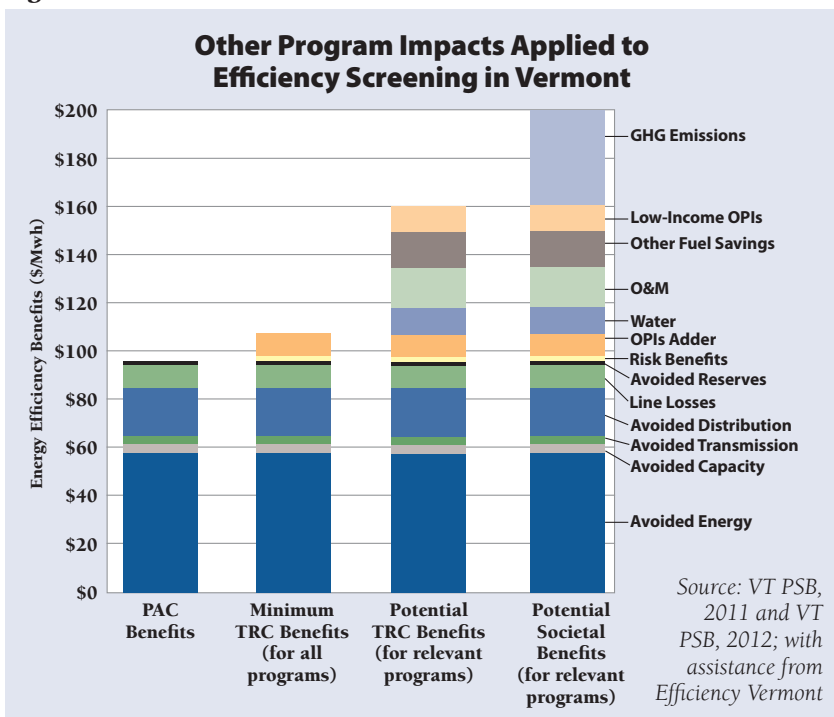
Participant Benefits. Comfort, health, employee productivity, savings on other fuels, water and sewer savings, and facility maintenance costs.

Societal Benefits. Air quality, water supply and quality, public health, solid waste, energy security, economic development.

An example of this is health benefits from low-income weatherization programs. By reducing moisture, mold, and air leakage, such programs can provide benefits that greatly augment the energy benefits. One evaluation found that these benefits were on the order of three times the program costs.⁷⁸

Figure 17-1 shows how consideration of different categories of benefits may affect the calculated economic benefits of energy efficiency measures.

Figure 17-1



78 Barnard, L.T., Preval, N., Howden-Chapman, P., Arnold, R., Young, C., Grimes, A., Denne T. (2011). *The Impact of Retrofitted Insulation and New Heaters on Health Services Utilisation and Costs, Pharmaceutical Costs and Mortality: Evaluation Of Warm Up New Zealand: Heat Smart*. Retrieved from <http://www.healthyhousing.org.nz/research/currentresearch/evaluation-ofwarm-up-new-zealand-heat-smart/>

17.3. Utility vs. Third-Party Providers

In some states, third-party providers such as the “Energy Trust of Oregon” and “Efficiency Vermont” implement statewide energy efficiency efforts. These providers receive funding from consumers through the utilities (typically through assessments or public benefits charges), but they are separate economic entities and generally are subject to oversight and regulation by the utility regulatory commission. The District of Columbia is an exception—oversight is provided by an agency of the city government.

Evidence suggests that these third-party providers do at least as well in achieving energy savings goals as the most motivated utilities. However, it is crucial for them to coordinate with the utilities, so that in addition to reducing power plant and transmission needs, the savings are concentrated in the locations where they are needed to avoid distribution-system upgrade costs and coordinated with utility system planning and operations. Coordinating customer messages and contacts is also important.

17.4. Range and Scope of Programs

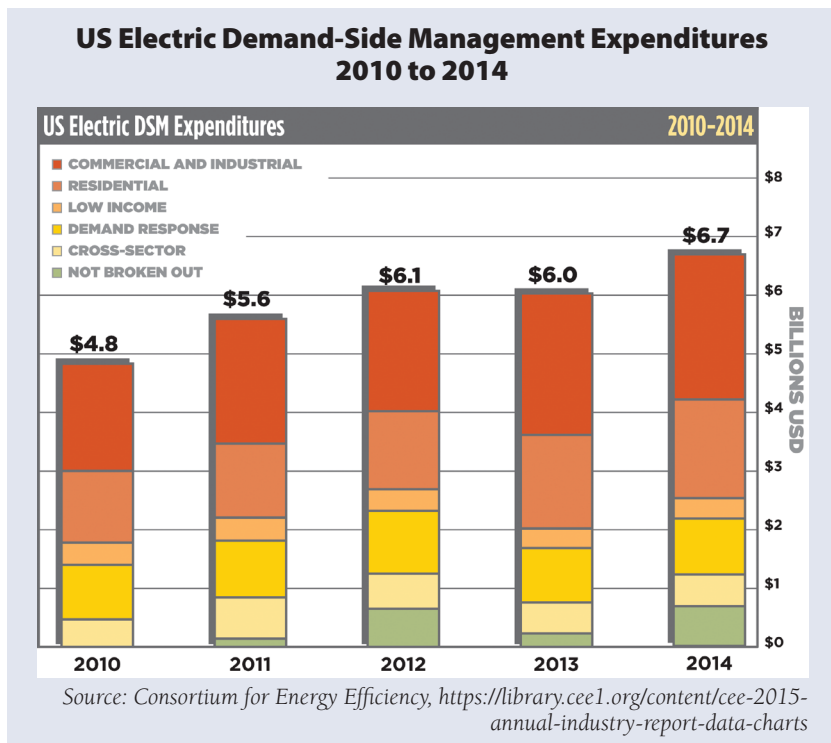
Energy efficiency programs address barriers that keep consumers from investing in efficiency on their own. These programs are effective only if consumers and other market actors voluntarily participate. Building energy codes and appliance and equipment energy standards, discussed later, are mandatory when they are enforced, but do not reflect all cost-effective energy efficiency measures. The barriers to be addressed include lack of consumer awareness that savings can be achieved, and lack of information about what to do and how to do it. Barriers also include financial limitations faced by the consumer, market failures owing to lack of awareness and training among vendors and builders, availability of components in local markets, and other factors.

In several states, the utility (or third-party provider) is charged with procuring all cost-effective energy efficiency. These organizations must operate a complete range of programs directed at all end-uses of energy and all classes of consumers. They promote efficiency in both new construction and retrofit applications, and work with residential, commercial, industrial, institutional, and agricultural customers.

In other states, utilities are only required to operate limited efficiency programs, restricted to some class of consumer (such as low-income or “hard to reach” customers), by a limited budget or savings-achievement target, or by other specified constraints.

Utilities or third-party providers offer grant and loan programs to help consumers pay for energy efficiency. They also provide technical assessments of energy efficiency measures and cost-effectiveness. They engage in market transformation programs, to help more efficient technologies become

Figure 17-2



commercially viable. And, perhaps most important, they engage in detailed program evaluation to ensure that their expenditures provide a net benefit to consumers.

In 2014, electric and gas utilities invested more than \$7 billion in energy efficiency programs.⁷⁹

The level of program activity and expenditure varies dramatically from one state to another. In general, the far west and the northeast have moved more aggressively than other regions on implementing energy efficiency.

17.5. Cost Causation and Cost Recovery

In most states, all electric consumers pay into the energy efficiency fund through a system benefit charge, and all electric consumers are eligible to participate in the programs. However, some programs are limited to residential and small business consumers. In some states, some or all of the

79 ACEEE Energy Efficiency Scorecard, 2015.

Figure 17-3

| Energy Efficiency State Scorecard | | |
|-----------------------------------|---|---------------|
| State | 2014 Electric Efficiency Spending (\$ Million) | \$ Per Capita |
| Rhode Island | 81.1 | 77.13 |
| Vermont | 48.1 | 76.76 |
| Massachusetts | 503.8 | 75.27 |
| Maryland | 319.3 | 53.86 |
| Connecticut | 180.6 | 50.22 |
| Oregon | 159.8 | 40.65 |
| Washington | 279.5 | 40.09 |
| Iowa | 108.5 | 35.11 |
| California | 1,237.6 | 32.29 |
| Minnesota | 135.6 | 25.02 |
| Arkansas | 72.2 | 24.39 |
| Hawaii | 33.3 | 23.74 |

*Source: ACEEE 2015 Energy Efficiency State Scorecard,
<http://aceee.org/research-report/1509>*

amounts paid by large industrial customers are sequestered and available only for the use of the customer who paid them, an approach termed *self-direction*.

In general, the utility is allowed to recover all of its expenditures for energy efficiency through a tracking mechanism (see discussion of tracking mechanisms in Chapter 14). In some states, both the revenue and expenditures for certain classes of customer are handled separately.

17.6. Cost-Benefit Tests

Regulators and utilities use several different cost “tests” to determine if energy efficiency programs are producing good value.

The most commonly used of these is the *total resource cost* (TRC) test, which compares all the resource-related benefits of energy efficiency measures to all the costs of the energy supply alternative. In the TRC, it is critical to count *all* quantifiable *non-energy* direct economic benefits of efficiency measures, considering their implications for water, sewer, natural gas, labor, and other savings. It is equally critical to count all the costs of the power

supply alternative, including production, transmission, distribution, line losses, reserve power plants to cover outages, quantifiable environmental costs of power supply, and any cost incurred directly by the customer.⁸⁰ A variation of the TRC, called the **societal cost test**, includes non-monetary costs and benefits, such as environmental damage, energy security, and health impact costs.

The **utility cost test**, or **program administrator cost test** (PACT, utility cost test, or UC test) measures only those costs and benefits that affect the utility or the customer's bill from the utility. The non-energy benefits of efficiency, as well as costs paid directly by the customer (not through the utility), are not counted. The only environmental costs and benefits included are those for which the utility must actually pay. For example, if a utility pays a 50 percent incentive for a lighting retrofit, only half the cost of the efficiency measure would be counted, and compared with 100 percent of the energy savings benefits as measured by the utility's cost of providing energy. Conversely, a high-efficiency clothes washer provides energy, water, sewer, and soap savings, but the PACT counts only the energy savings. The PACT also excludes many of the environmental costs of generating electricity. The PACT is a useful tool for determining if a utility's limited efficiency budget is helping achieve the maximum level of efficiency, but it does not measure the overall cost-effectiveness of the program.

The **rate impact measure** (RIM) test measures whether a given efficiency program causes rates to rise or fall for non-participants in the program. The **participant cost test** (PCT) measures whether participants are better off. Most energy efficiency measures that save a significant amount of energy fail the RIM test and pass the PCT.

Utility costs go up to pay for all or part of the cost of energy efficiency measures. In addition, utility revenues decline because the customers installing the energy efficiency measures use less energy. As a result, higher utility costs must be divided among fewer utility sales in setting rates, and rates per unit of energy go up, even though the total of customer energy bills goes down. Some efficiency programs focused on peak-period usage do pass the RIM test, because they avoid the need for expensive, seldom-used resources needed only to meet peak demands while not reducing overall revenues much.

The UC test, the RIM test, and the PCT reflect distinct points of view. These tests can be distinguished from the TRC and the societal cost test, which take broad points of view.

80 Some states have applied the TRC in a more limited fashion, excluding avoided transmission and distribution capacity costs, marginal line losses, quantifiable environmental costs, or non-energy benefits such as water, sewer, and soap savings. Where costs or benefits are excluded, the value of the analysis is impaired.

Although these tests are implemented in all states, they are implemented with some differences. The most significant difference is which benefits are counted. Some states are expansive in identifying relevant benefits, whereas others are limited. Other assumptions, like discount rates for long-term valuation of savings, may also differ.

17.7. Codes, Standards, and Market Transformation

Many energy efficiency measures are so cost-effective that state or federal law mandates require them. The most familiar of these are building energy codes for new construction and appliance efficiency standards for major home appliances. Such codes and standards generally are implemented after measures have been *proven up* through incentive programs offered by utilities or third-party providers.

In a variety of ways, utility or government investment in energy efficiency research, development, and demonstration can lead to *market transformations*, through which an improved mix of products is offered to and purchased by consumers. For example, offering incentives to manufacturers may lead to the availability of higher-efficiency products, and educating architects and developers may lead to the specification of higher-efficiency measures in new buildings. These methods may be far less expensive than programs to influence ultimate consumers. Once the measures are proven to be cost-effective and feasible for suppliers, they may be gradually folded into applicable codes and standards.

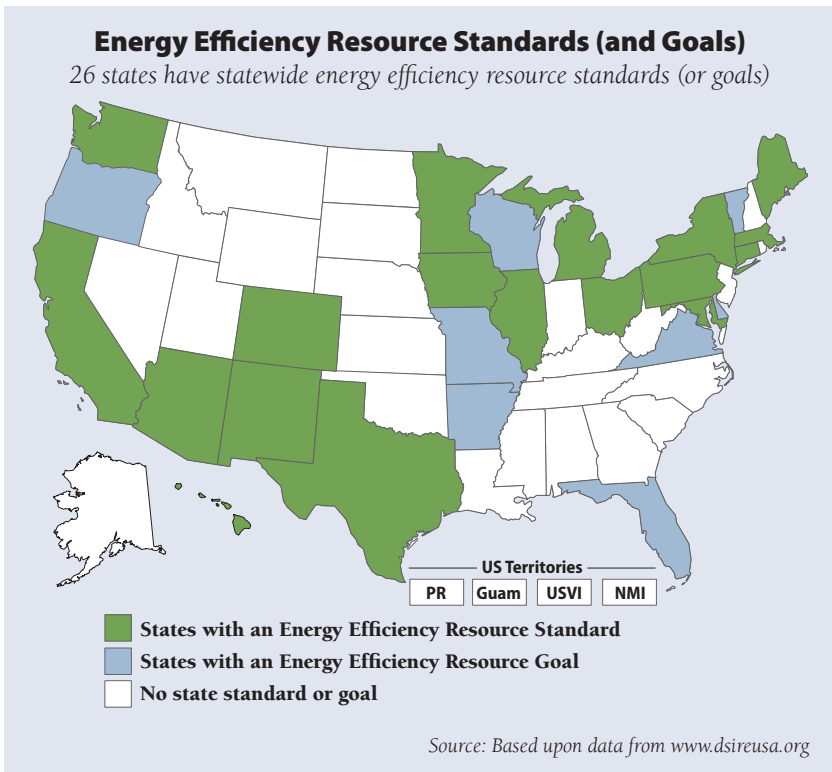
In addition to government-adopted codes and standards, there are voluntary building energy rating systems, such as Leadership in Energy and Environmental Design (LEED) options promulgated by the US Green Building Council. Regulators may consider allowing or requiring utilities to include financial support for these standards in energy efficiency program design.

17.8. Energy Efficiency Resource Standards

Many states have adopted *energy efficiency resources standards* (EERS) for their utilities. An EERS requires a utility to meet a specified portion of its energy needs through energy efficiency—in effect, energy efficiency would decrease the demand for power by a certain amount and can thus be considered a resource in its own right. The standards do not necessarily require that the utilities invest funds directly in actual installations: support of codes, standards, and encouragement of voluntary programs may suffice to achieve some or all of the required energy efficiency. As of 2015, 26 states have adopted EERS of some form, and four have pending standards.⁸¹

81 For a map showing the status of EERS around the United States, see: <http://www.dsireusa.org/resources/detailed-summary-maps/>

Figure 17-4



For more information:

American Council for an Energy-Efficient Economy (ACEEE). *State Energy Efficiency Policy*. Retrieved from <http://aceee.org/sector/state-policy>

Barnard et al., *Evaluation of Warm Up New Zealand: Heat Smart*, 2011.

Consortium for Energy Efficiency. (2016). *2015 State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts*. Retrieved from <https://library.cee1.org/content/cee-2015-state-efficiency-program-industry>

Harrington, C., Murray, C., & Baldwin, L. (2007). *Energy Efficiency Policy Toolkit*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raonline.org/docs/RAP_Harrington_EEPolicyToolkit_2007_01_04.pdf

Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raonline.org/document/download/id/6739>

- Neme, C., & Grevatt, J. (2016, January). *The Next Quantum Leap In Efficiency: 30 Percent Electric Savings in Ten Years*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://raponline.org/document/download/id/7944>
- Neme, C., & Sedano, R. (2012). *US Experience with Efficiency as a Transmission and Distribution Resource*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/4765>
- Renewable Energy and Energy Efficiency Partnership (REEEP). (2010). *Compendium of Best Practices: Sharing Local and State Successes in Energy Efficiency*. Retrieved from http://www.raponline.org/docs/RAP_REEEP_CompendiumofBestPractices_2010_05_28.pdf
- Schwartz, L. (2010). *Smart Policies Before Smart Grids: How State Regulators Can Steer Smart Grid Investments Toward Customer-Side Solutions*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/docs/RAP_Schwartz_SmartGridACEEESummerstudy_2010_8_17.pdf
- Woolf, T., et al. (2012). *Energy Efficiency Cost-Effectiveness Screening*. Synapse Energy Economics and The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/6149>

18. Renewable Energy

A variety of regulatory policies are focused on supporting the deployment of renewable energy, integrating variable renewable generation into the electric grid, and establishing tariffs for customers who generate electricity from renewables on their own premises (i.e., “behind the meter”). This chapter examines some of those policies.

18.1. Renewable Portfolio Standards

An RPS is a policy that specifies a minimum share of electricity to be supplied from renewable resources by each affected entity. A majority of states have enacted some version of an RPS (see Figure 18-1), although sometimes by a different name (e.g., Renewable Electricity Standard). A number of bills have been introduced in Congress to create a federal RPS policy, but none have as yet been enacted.

Every state RPS policy is unique. In most, the RPS is expressed as a requirement that covered⁸² utilities and retail suppliers produce or procure a minimum percentage of the electricity they sell to retail consumers from eligible resources⁸³ in each calendar year. So, for example, a utility might be required to produce or procure at least 20 percent of its retail energy sales from eligible resources in the year 2020. Because RPS requirements are typically expressed as a percentage of retail sales, investment in energy efficiency reduces the level of renewable energy investment required. Some

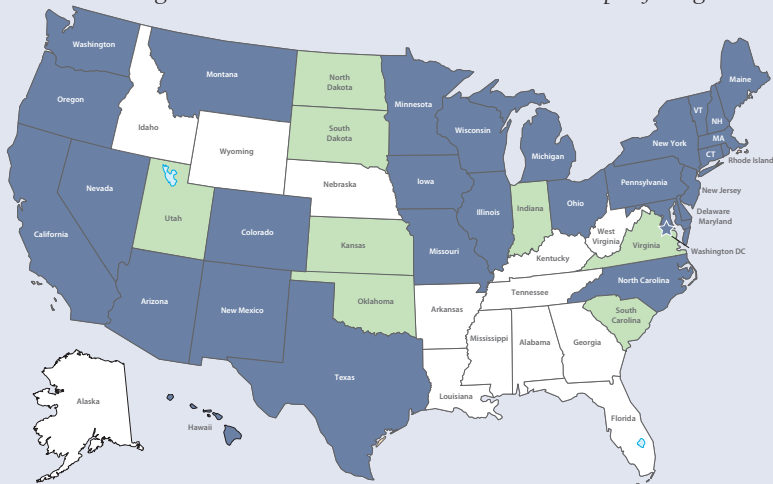
82 State policies do not always apply to every utility or retail supplier. Some states apply their policies only to certain types or sizes of entities (e.g., investor-owned utilities, or any entity with annual retail sales above some threshold amount).

83 State policies generally include a finite list of eligible resources, but some policies include a procedure for modifying the list. A few states have adopted “Clean” or “Alternative” Energy Standards in which energy efficiency or non-renewable resources such as nuclear reactors or fossil-fueled combined heat and power systems are eligible. Some states even allow non-electric renewable energy, such as solar hot water heating, to be converted into an MWh equivalent and used for compliance. Some states also allow regulated entities to comply by making alternative compliance payments in lieu of procuring energy from eligible resources. See: Regulatory Assistance Project and Center for Climate and Energy Solutions. (2011, November). *Clean Energy Standards: State and Federal Policy Options and Implications*. Retrieved from <http://www.raponline.org/document/download/id/4714>. Any resource can be the subject of a resource standard. In the previous chapter, an energy efficiency resource standard was discussed. In the United States, there are also examples of resource standards for demand response and storage.

Figure 18-1

Renewable Portfolio Standard Policies

28 states, Washington DC, and two US territories have a renewable portfolio standard. Eight states and two territories have renewable portfolio goals.



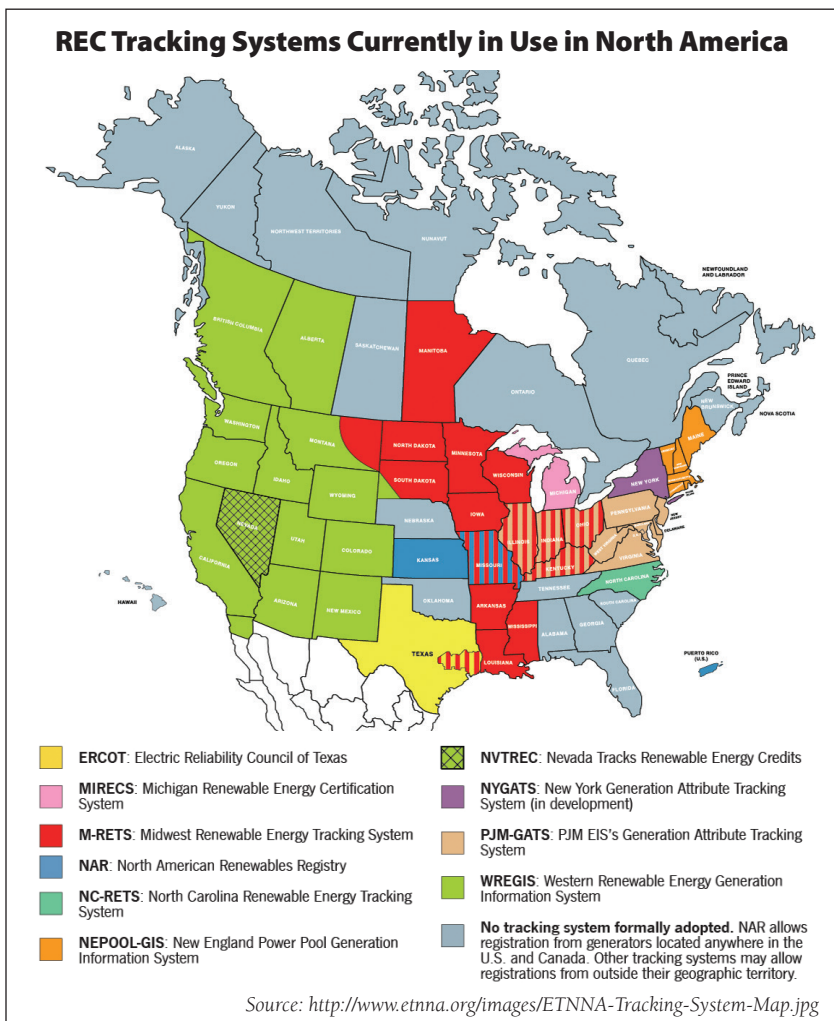
■ Renewable portfolio standard * Extra credit for solar or customer-sited renewables
■ Renewable portfolio goal † Includes non-renewable alternative resources

Arizona: 15% by 2025
California: 50% by 2030
Colorado: 30% by 2020 (IOUs), 10% by 2020 (co-ops and large munis)*
Connecticut: 27% by 2020
Delaware: 25% by 2026*
Hawaii: 100% by 2045
Illinois: 25% by 2026
Indiana: 10% by 2025†
Iowa: 105 MW
Kansas: 20% by 2020
Maine: 40% by 2017
Maryland: 20% by 2022
Massachusetts: 15% by 2020 (new sources). 6.03% by 2016 (existing sources)
Michigan: 10% and 1,100 MW by 2015*
Minnesota: 26.5% by 2025 (Xcel: 31.5% by 2020)
Missouri: 15% by 2021
Montana: 15% by 2021
Nevada: 25% by 2025*
New Hampshire: 24.8% by 2025
New Jersey: 20.38% RE by 2020 plus 4% solar by 2027
New Mexico: 20% by 2020 (IOUs), 10% by 2020 (co-ops)

New York: 29% by 2015
North Carolina: 12.5% by 2021 (IOUs), 10% by 2018 (co-ops and munis)
North Dakota: 10% by 2015
Ohio: 12.5% by 2026
Oklahoma: 15% by 2015
Oregon: 25% by 2025 (large utilities)* 5% - 10% by 2025 (smaller utilities)
Pennsylvania: 18% by 2021†
Rhode Island: 14.5% by 2019
South Carolina: 2% by 2021
South Dakota: 10% by 2015
Texas: 5,880 MW by 2015*
Utah: 20% by 2025*
Vermont: 75% by 2032
Virginia: 15% by 2025*
Washington: 15% by 2020*
Washington DC: 20% by 2020
Wisconsin: varies by utility; ~10% by 2015 statewide
US Territories:
Northern Mariana Islands: 20% by 2016
Puerto Rico: 20% by 2035
Guam: 25% by 2035 (goal)
US Virgin Islands: 30% by 2025 (goal)

Source: Based upon data from www.dsireusa.org

Figure 18-2



RPS policies also include “carve-outs” specifying a minimum share of electricity from specific resources, such as distributed solar.

To determine if utilities and retail suppliers have complied with an RPS percentage requirement, it is necessary to track the amount of renewable energy they sell to their retail customers. Most state RPS policies rely on **renewable energy certificate** (REC) tracking systems for this purpose.⁸⁴ Figure 18-2 shows the REC tracking system currently in use in North America.

⁸⁴ RPS policies are typically enforced by the state PUC based on reports filed by covered entities.

A REC is a uniquely numbered electronic certificate that is associated with the renewable attributes of one megawatt-hour (MWh) of generation from a registered facility. RECs can be traded, bought, and sold between any two willing parties as an unbundled commodity (i.e., the REC and the actual electricity can be sold separately). The REC tracking system identifies all of the key characteristics that determine if a REC can be used for RPS compliance in a given state, including: the name, location, and type of facility that generated the electricity; the year the electricity was generated; and the current owner of the REC. When a utility or retail supplier uses a REC for RPS compliance in any state, the REC is retired in the tracking system so it cannot be used a second time. REC tracking systems are also used to track voluntary purchases of renewable energy for non-RPS purposes, again to ensure that the attributes of any one MWh of renewable generation can't be claimed by two parties.

RECs are also a key instrument in voluntary renewable energy markets.⁸⁵ RECs are also used as a means for substantiating claims concerning renewable energy use, and often, corporate and transactional sustainability. The Federal Trade Commission has published guidelines on such claims and how to substantiate them.⁸⁶

18.2. Relationship between Renewable Energy Development and Carbon Regulation

Regulations that directly or indirectly impose a price on carbon emissions, as discussed in Chapter 20, have the effect of increasing the cost of generating electricity from emitting resources. If the cost imposed on carbon emissions is large enough, this kind of policy could spur a rapid growth in renewable (or nuclear) energy deployment.

18.3. Net Metering

The Energy Policy Act of 2005 added a net metering ratemaking standard to the original list of PURPA ratemaking standards. State regulators were required to consider and make a timely determination concerning whether to implement each ratemaking standard for the electric utilities for which they have ratemaking authority. The standard reads as follows:

Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term “net metering service” means service to an electric consumer under which electric energy generated by that electric consumer

85 See <http://resource-solutions.org>.

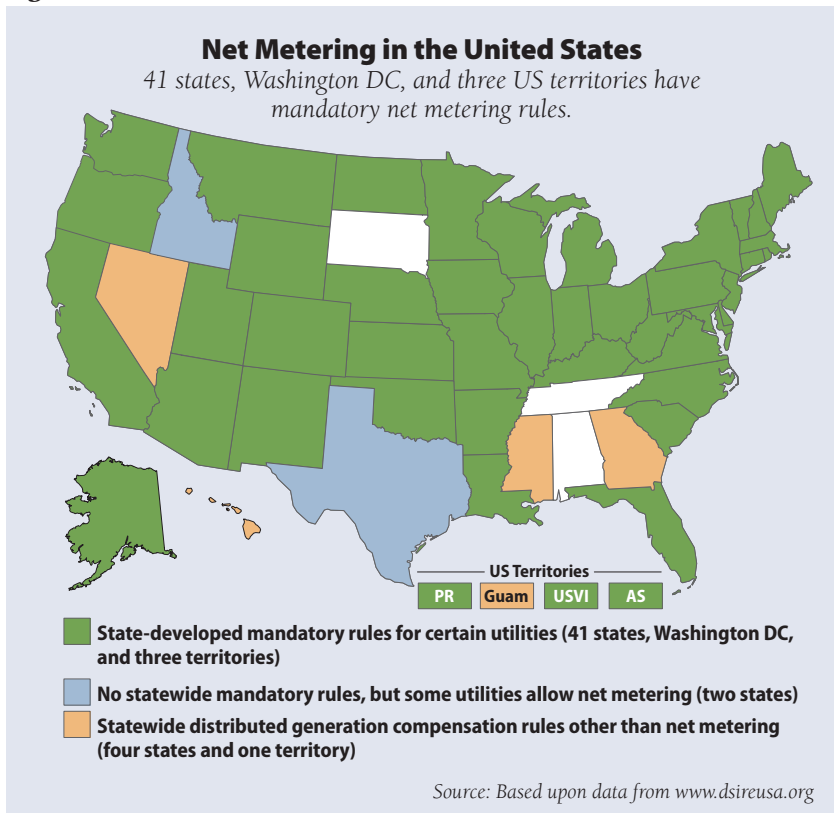
86 See 16 CFR Part 260 regulations.

from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.⁸⁷

A NEM tariff bills the customer, or provides a credit to the customer, based on the net amount of electricity consumed during each billing period (i.e., the kWh difference between electricity consumed and electricity generated). Provisions are made for periods in which the net amount consumed is negative (generation exceeds consumption). NEM does not require separate metering of consumption and generation; a bidirectional meter can be used to measure net consumption during relevant time periods.

Today, NEM is the most commonly used tariff design for customers who have behind-the-meter generation. More than 40 states have adopted some form of a NEM policy, as indicated in Figure 18-3. The details of these policies, however, vary widely from state to state, notably with respect to the amount of

Figure 18-3



87 16 USC 2621(d)(11).

credit awarded to customers for net excess generation in a billing period. Some tariffs credit the customer at a full volumetric retail rate reflecting production, transmission, and distribution costs, whereas other tariffs award a credit based only on the fuel and purchased power component of rates.

NEM tariffs have been a significant facilitator and impetus for small-scale renewable energy deployment. More than 90 percent of all rooftop PV systems in the United States, and nearly all residential PV systems, operate under a NEM tariff.

18.4. Third-Party Ownership

Another factor driving renewable energy deployment is the emergence of third-party ownership models. There are many variations on these models, but what they have in common is that the customer who hosts a renewable energy system (usually a PV system) on their premises does not, in fact, own the system that is installed. The system is financed, installed, and initially owned by a non-utility third party that has a power purchase agreement (PPA) or a similar mutually beneficial contractual arrangement with the customer. The customer may obtain ownership of the system at the end of the lease term.

Two third-party PPA models are common. In one model, the customer purchases all of the output of the system at a rate established by the third party. In many places the rate is less than the kWh charge in the utility tariff, but in some places the rate exceeds the utility tariff rate in effect at the time the system is installed, with the expectation that the utility tariff rate will increase with inflation and the customer will realize net benefits in later years. In the second model, the customer receives all of the output of the system and pays a monthly leasing fee for the privilege. In many places the monthly leasing fee is set at a level that reduces the customer's electricity bill. Regardless of which model is implemented, third-party financing companies are generally for-profit entities and thus the rate or monthly payment established includes all costs of financing the system including profit.⁸⁸

One reason third-party ownership has flourished is that many consumers are unable to take advantage of state or federal tax incentives for renewable energy. Third-party finance normally involves an owner with an immediate use for tax benefits, and they can therefore provide the system to the customer at a lower cost than direct purchase.

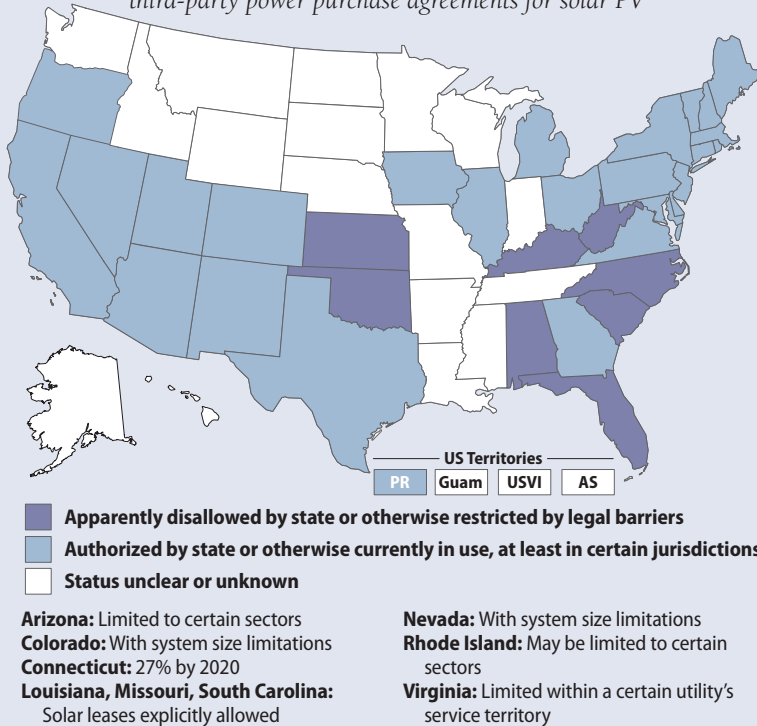
Third-party ownership models indirectly challenge the traditional

88 There are a few instances in which non-profit organizations have invested in shared solar systems to provide power or financial benefits for low-income consumers, but these are rare. See the discussion of low-income shared renewable programs in Chapter 21. As for-profit businesses, third-party owners will take full advantage of any existing federal and state tax incentives for renewable energy. This model can therefore offer a distinct cost advantage over customer-owned renewables in cases in which the customer is a tax-exempt institution and not eligible for tax incentives.

Figure 18-4

Third-Party Power Purchase Agreement Status in US States

At least 33 states, Washington DC, and Puerto Rico authorize or allow third-party power purchase agreements for solar PV



Source based on information found at www.desireusa.org

monopoly model in which only the regulated or consumer-owned utility may sell electricity at retail to end-use customers. Roughly two-thirds of the states have overcome this challenge by explicitly authorizing third-party ownership models. But in many other states, the legality of this model is unclarified or it is explicitly forbidden. Figure 18-4 shows the status of third-party ownership rules in the United States.

Third-party ownership models have had a significant impact on renewable energy deployment, especially in the residential sector. In each year from 2012 through 2015, more than half of the newly installed residential PV capacity was owned by third parties.⁸⁹

89 Litvak, N. (2015, July). *U.S. Residential Solar Financing 2015-2020*. GTM Research. Retrieved from <https://www.greentechmedia.com/research/report/us-residential-solarfinancing-2015-2020>

18.5. Shared Renewable Programs

Shared renewable systems (including “community solar” programs) offer yet another way to structure renewable energy deployment. These programs allow customers to subscribe to or own shares of larger systems, and receive utility bill credits (or less commonly, payments) based on the output of renewable energy systems that are not installed behind their individual meters.

Shared solar programs have become popular because they often cost less owing to economies of scale. They also broaden participation opportunities to customers who cannot install a PV system on their residence, for example because they have a shaded property.

Here again, the design of shared solar programs varies widely—not just from state to state, but even from utility to utility. Some of the key variables in these programs relate to who owns the PV system, whether and how customers make an upfront investment in the system, and in what form does the customer get compensated.

Roughly a dozen states have enacted legislation enabling shared renewable energy programs (and in some cases dictating program design characteristics), but utilities in many other states have supported shared renewable projects on a voluntary basis without explicit legislative authorization.⁹⁰

18.6. Renewable Energy Integration

There are two kinds of integration challenges associated with the deployment of renewable energy. The first is the challenge of siting and interconnecting renewable generation. The second is the challenge of operating the grid on a real-time basis.

The economics of renewable energy depend strongly on the quality of the renewable resource. For example, wind power is only cost-effective in areas with a good wind resource. This means that renewable generating facilities must be located where the resources are good, and this is often, although not always, remote from large load centers. New transmission lines are often needed to deliver large amounts of renewable energy to load centers. This can create a “chicken and egg” problem in which new generation cannot be justified without available transmission, and vice versa. In some areas, transmission capacity originally built for large thermal plants that have been retired or are planned for retirement is being redeployed for renewable energy transmission.⁹¹ Where developing wind energy is a priority, transmission can

90 The Interstate Renewable Energy Council maintains a catalog of these programs at <http://www.irecusa.org/2015/11/shared-solar-program-catalog-3/>.

91 This is most notable for lines into California from Arizona, Nevada, and Utah, where coal plants built for the California market are required to be retired from the California utility portfolios, and the lines are being used to move wind, solar, and geothermal energy into California.

be built to **renewable energy zones** (REZ) to accelerate investment. There can also be heated debate about which parties benefit from new transmission lines built to connect renewable resources to load, and how the costs of those lines should be allocated to utilities and their customers. Except in areas with an isolated, intrastate grid (Hawaii, Alaska, and parts of Texas), FERC has regulatory authority over interconnection rules at the transmission level and approves tariffs for transmission cost allocation.

Interconnection can also be a big regulatory issue for small-scale renewables like rooftop PV systems that operate at the distribution level. Utilities have interconnection standards to protect the distribution grid from damage and to ensure the safety of utility workers and customers. These standards are subject to state or local regulation.

Interconnection standards have limited the amount of variable generation that could be sited on the distribution system (typically 15 percent of the maximum load on a circuit), but advances in technology along with growing experience are leading to relaxation of conservative limits.

Hawaii represents a place where the standard has changed dramatically. Hawaii has the highest level of rooftop solar in the United States, and is viewed by many as a “postcard from the future.” The state originally allowed PV installations only up to ten percent of the circuit peak demand, but as they have gained experience with distribution system management with high levels of PV installed, regulators have now increased this allowance to 250 percent of the minimum daytime load. Originally, Hawaii’s interconnection standard required PV systems to shut down in response to system transients. This exacerbated the challenge of generating unit outages, which would be magnified by PV systems shutting down in response. Hawaii now requires new solar inverters to be capable of and set to “ride-through” system disturbances.

Because some renewable generation resources (e.g., wind and solar) are variable in their output, and because these variable energy resources (VERs) have near-zero operating costs, they are usually allowed to generate as much electricity as they can, whenever the resource is available. This leads to more variability in the net load shape (i.e., gross customer demand minus the output of uncontrolled VERs) that utilities and system operators must serve than was historically the case. Rather than planning to serve fairly predictable variations in gross customer demand, utilities and system operators now must plan to serve less predictable variations in *net load*.

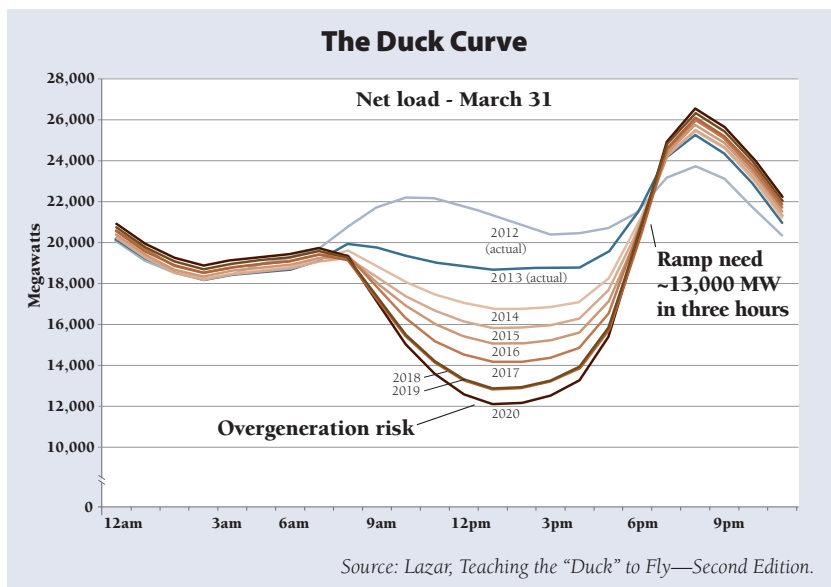
The challenges presented by high penetrations of VERs vary depending on the type and location of the renewable resources. Wind resources produce energy at different times in different places, so managing wind resources can produce an integration challenge. Solar PV resources produce energy during the daylight hours only, and thus high penetrations of solar PV can present a particular type of integration challenge. Fortunately there are many

cost-effective tools available to meet the integration challenge, and there are resources available to explain the full range of options.⁹²

One integration challenge that has drawn attention in the last few years is the challenge of high penetration of solar PV in the southwest. This challenge is often referred to as the duck curve phenomenon.⁹³

Historically, the load shape on utility systems has often included daily peaks in the morning and early evening, with a period of relatively lower demand in the mid-day period. The mid-day period between the morning and evening peaks is when solar generation is at a maximum. Thus, as more solar energy is added to the grid, the load to be serviced from dispatchable resources may eventually sag in the middle of the solar day when solar generation is highest, even as the load to be served in the early evening after

Figure 18-5



92 For more on the challenge and the solutions, see: Hogan, M., & Paulos, B. (2014). Dealing with the Duck. *Public Utilities Fortnightly*. Retrieved from <http://bit.ly/1iKNu2o>; Bird, L., Milligan, M. & Lew, D. (2013, September). *Integrating Variable Renewable Energy: Challenges and Solutions*. NREL/TP-6A20-60451. Retrieved from <http://www.nrel.gov/docs/fy13os-ti/60451.pdf>; and Schwartz, L., Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Hogan, M., Lamont, D., & Kirby, B. (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*. Western Governors' Association. Retrieved from http://www.westgov.org/component/docman/doc_download/1610-meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integrationchallenge-full-report?Itemid=

93 See Lazar, Teaching the "Duck" to Fly—Second Edition.

the sun goes down may continue to grow. The need to rapidly ramp down dispatchable generation resources in the morning and ramp them back up rapidly in the evening has been dubbed the duck curve because of the resemblance of the net load curve to the silhouette of a sitting duck, as shown in Figure 18-5. Ramping requirements are projected to be one of the most difficult issues for renewable energy integration as solar deployment grows, but solutions to this challenge do exist.

18.7. Renewable Energy Rate Issues

The goal of retail rate design, as described in earlier chapters, is to set prices that are economically efficient and fair to consumers and that enable utilities to recover their costs of providing service—including a return of, and on, their investment.

Rate issues related to renewable energy include net metering, provision of standby and supplemental service, recovery of infrastructure costs needed to support renewable energy, value of solar analysis, and time-varying pricing. These issues are addressed in Chapter 10.

For more information:

Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., and Migden-Ostrander, J., (2013, November). *Regulatory Considerations Associated With the Expanded Adoption of Distributed Solar* (Report No. TP-6A20-60613). Golden, CO: National Renewable Energy Laboratory and The Regulatory Assistance Project. Retrieved from <http://www.nrel.gov/docs/fy14osti/60613.pdf>

Jones, T. (2015, October). *Renewable Energy and the Clean Power Plan* (Parts 1 & 2). San Francisco, CA: Center for Resource Solutions. Retrieved from <http://resource-solutions.org/press-releases/110215/>

Linvill, C., Migden-Ostrander, J., & Hogan, M. (2014, June). *Clean Energy Keeps the Lights On*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from <https://www.raonline.org/document/download/id/7175>

Lazar, *Teaching the “Duck” to Fly—Second Edition*.

NITI Aayog, Government of India. (2015, February). *Report on India’s Renewable Electricity Roadmap 2030: Toward Accelerated Renewable Electricity Deployment* (Executive Summary). Retrieved from <https://www.raonline.org/document/download/id/7511>

19. Aligning Regulatory Incentives With Least-Cost Principles

In Chapter 12, we discussed some problems with conventional regulation, including the incentives it gives utilities to maximize sales. Commissions have become increasingly concerned with these incentives, and have pursued options to align the utility's interest in maximizing net income with the consumer's interest in minimizing energy costs by reducing energy use.

This chapter discusses how implementation of energy efficiency may reduce utility profits, and how regulators can change the traditional regulatory framework to improve utility receptiveness to energy efficiency programs.

19.1. Effect of Sales on Profits

Although energy efficiency is generally the most cost-effective way to meet the demand for additional energy services, in general, if utility sales go down, revenues and profits decline. Because the utility's return is embedded in the rate per unit for electricity (or gas), each incremental sale brings incremental profit, and each lost sale costs the utility net income.

As we noted in discussing the throughput problem in Chapter 12, utility rates generally are designed by regulators to reflect long-run costs, such as permanent employees, power plants, and distribution lines. But in the short run, between rate cases, the only significant change in utility costs as sales go up or down is the **variable cost** of producing or purchasing more or less power. Because incremental sales produce revenue that usually exceeds incremental expense in the short run, a utility has a strong motive to increase its throughput.⁹⁴ If sales go up, the existing investment in power plants and power lines is spread out over a larger number of units, so the utility is getting more revenue out of them.

94 This economic characteristic—that of marginal revenue almost always exceeding short-run marginal cost—is a general feature of natural monopolies and is a powerful driver of management behavior. Average cost, on which prices are based, usually exceeds short-run marginal cost, across very wide ranges of demand. It is particularly true of distribution-only utilities, which face virtually no incremental cost (in the short run) for the delivery of an incremental unit of energy.

19.2. Techniques for Aligning Incentives

A number of measures have attempted to overcome this throughput incentive, with varying success and side effects. Some of these have reduced financial risk for utilities by giving them greater certainty of earning their expected return. (In general, measures that reduce utility risk should be accompanied by a review of the allowed rate of return to ensure that consumers pay a fair rate for both the service provided and the risk borne by the utility.)

19.2.1. Revenue Regulation or “Decoupling”

Decoupling can reduce throughput incentives, because (as noted earlier) it ensures that the utility’s revenues, in certain defined categories, are not affected by sales volumes.⁹⁵ Traditional regulation sets a revenue requirement, based on costs, then divides that by sales and calculates rates. The rates remain constant, even though the sales may vary. Decoupling turns this around. It adjusts rates in response to changes in sales, so that the amount of revenue recovered stays at the level approved by the commission.

Some costs do go up and down with sales volumes. Fuel and purchased power are examples, but for most utilities, these are recovered through the FAC discussed in Chapter 14. A decoupling mechanism typically recovers all the utility’s costs that are not covered by the fuel and purchased power adjustment clause (FAC) or by other adjustment clauses. All distribution and power supply costs excluded from the adjustment clauses are recovered through the decoupling mechanism. For a distribution utility operating in a restructured state, the power supply costs are neither a component of the revenue requirement nor the decoupling mechanism. For example, a one-percent decrease in sales would cause a less than one-percent increase in the rates, because there are some variable power cost savings resulting from reduced production (e.g., avoided fuel costs).

Some decoupling mechanisms operate on a *current* basis, applying the necessary change in rates as bills are sent out each month to ensure that the right amount of money is collected. This is most common for natural gas utilities. Most electric decoupling mechanisms operate on a *deferral* basis, with any amounts not recovered or over-recovered owing to sales variations being deferred and recovered, or refunded, the following year. Some mechanisms set a fixed or formula amount of revenue to be recovered each month or year, whereas others set an amount to be recovered per customer, so that changes in the number of customers result in changes in

95 This is an abbreviated discussion of the topic; several detailed RAP papers on decoupling are available on the RAP website.

utility revenues. In all cases, however, consumers continue to pay **volumetric rates**, so that reduced usage by any one consumer means a lower bill for that consumer. In order to prevent unfair cost dislocation, this means that energy efficiency programs that drive decoupling charges should be designed to reach the widest range of impacted customers.

Decoupling mechanisms are divided into three categories:

- **Full Decoupling.** All variations in sales volumes are included in the calculation of the decoupling adjustment.
- **Limited Decoupling.** Only specific causes of changes in sales volume are included. For example, changes in sales owing to weather may be excluded, with sales volumes recalculated based on the normal weather conditions used in the rate case. These are common for natural gas utilities, adjusting for sales variations attributable to weather.
- **Partial Decoupling.** Only a portion of the revenue lost or gained owing to sales volume variations is included in the calculation of the decoupling adjustment. For example, the commission may allow only 90 percent of the lost or gained revenue to be included.

There are two general approaches to decoupling used in the United States. The choice of methods primarily depends on whether the mechanism is intended to recover all costs (including power supply) or only distribution costs.

- **Annual Review (Attrition) Decoupling.** The regulator reviews all costs, the allowed return, and contested items generating the revenue requirement in a periodic general rate case. In each year between rate cases, the regulator reviews changes in costs, but does not revisit contested issues, and establishes a new revenue requirement. This method is most applicable where investments in power plants and transmission lines are included in the decoupling mechanism (e.g., California and Hawaii)
- **Revenue Per Customer (RPC) Decoupling:** The regulator establishes an allowed distribution revenue per customer in a general rate case in which all costs are examined, and establishes an allowed annual (or monthly) average distribution revenue per customer. In future years, the allowed revenue requirement is adjusted by multiplying the change in customers by the allowed revenue per customer. This approach does not work well for recovery of power supply investment, because those costs tend to decline between rate cases as plants are depreciated.

Decoupling is relatively simple to administer. For each adjustment cycle, whether it is a month or a year, the amount of revenue allowed for that period in the rate case determined formula is compared to the amount actually recovered. A surcharge or credit is imposed to make up the difference. Except for the effects of weather, typical surcharges or credits are

no more than a few percent, because sales volumes from non-weather causes typically do not vary all that much from the levels assumed in the general rate case. In limited decoupling mechanisms, where changes in sales owing to weather are normalized, the rate changes are typically a fraction of one percent, but customers are exposed to higher bills during months of severe (hot or cold) weather.

Sometimes decoupling is referred to as *formulary rates*, in which the commission adopts a rate formula in the rate case, and the rates themselves are adjusted periodically between rate cases by updating the data used in the formula, including sales volumes. However, formulary rates can also encompass other types of incentive and adjustment mechanisms.

19.2.2. Lost Margin Recovery

Lost margin recovery, or lost contribution to fixed costs, is a form of limited decoupling. Lost margin recovery provides a mechanism through which the utility recovers any revenues lost as a result of utility-operated energy efficiency programs. In the flat rate design shown in Figure 19-1, for example, the utility has about \$0.05/kWh included in the rate for costs that do not change as usage changes.

Figure 19-1

| Illustrative Lost Revenue Adjustment Mechanism Rate | |
|---|------------|
| Customer charge | \$5.00 |
| Distribution charge | \$0.05/kWh |
| Power supply charge | \$0.05/kWh |

The utility would get to recover an additional \$0.05 for each kWh of sales displaced by utility efficiency programs—the amount of the “lost” distribution service revenue. However, the utility would not get any recovery of lost margin if consumers invested in efficiency themselves, or if sales declined because of economic conditions, weather, or other factors.

Because fewer costs are included, the rate changes are generally smaller than under full decoupling, but there are additional risks that regulators should consider. Among these are the risk that utilities will resist market-driven efficiency improvements and building code updating, because they are only compensated for lost revenues resulting from utility programs.

Lost margin recovery requires a more extensive review and analysis of the amount and value of savings. As a result, it may lead to more significant disputes in the rate-setting process. Furthermore, added sales still rebound to

the benefit of the utility, so the throughput incentive to build load remains.

19.2.3. Frequent Rate Cases

Filing frequent rate cases is another way in which a utility can keep its allowed revenue and the actual revenue tracking closely, so that reduced sales from efficiency measures do not lower profits very much or for very long. Even if efficiency efforts are reducing sales, if the utility files a new rate case every year, it is never more than one year of sales change “off” from the level set in the rate case. However, even in that short period of time, energy efficiency will diminish profits slightly; utilities may be unmotivated to have efficiency programs succeed; and increased sales still benefit the bottom line. Frequent rate cases are also time-consuming and expensive: between the utility, the commission, and the intervenors, a rate case can easily cost \$5 million in staff time, expert witnesses, and attorney fees. Although there are good reasons to have a periodic rate case, going through the process solely for the purpose of reflecting the effects of energy efficiency, when a decoupling mechanism can have the same effect, is quite burdensome.

19.3. Future Test Years

Some commissions use *future test years* to set rates. As Chapter 8 describes, these set the expected sales based on forecasts of costs and sales. If the utility has forecast that sales will decline because of efficiency efforts, this will already be reflected in the sales estimate used in the rate case, and the utility will recover the right amount of revenue if energy efficiency achievement is as expected. Even in this situation, however, the utility would earn higher profits if energy efficiency achievement were lower, so the throughput incentive remains. In theory, a commission could set rates for several years in advance, building in rate adjustments based on forecasts, to avoid annual rate cases. However, this would have the same problem—if the energy efficiency performance fell short of the forecast, utility earnings would increase, creating a multiyear throughput incentive.

The use of future test years is a very controversial issue in regulation; many analysts and regulators fear that utilities use the future test year scheme to inflate projected budgets, obtain higher revenue requirement allowances, and then constrain spending to lower levels to boost earnings.

19.4. Straight Fixed/Variable Pricing (SFV)

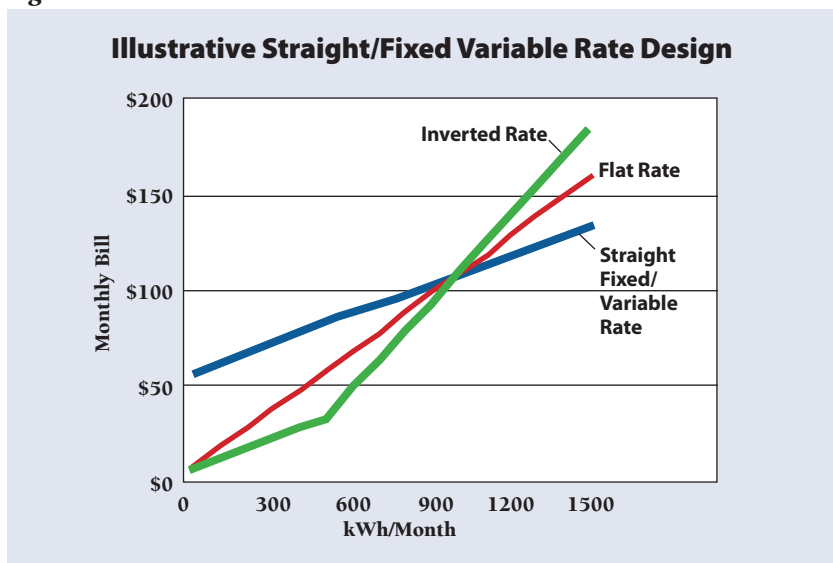
Some utilities and regulators have implemented pricing schemes that collect not only customer-specific costs, but all of the distribution costs that do not vary with sales in the short run as a fixed charge each month. They then include only the variable costs of fuel and purchased power in the rate per unit. This is called **straight fixed/variable pricing**, or SFV. This

compares to the rate design discussed in Chapter 10.1, in which the customer charge is based solely on the cost of meters, meter reading, and billing.

Figure 19-2 shows an example of SFV, assuming fuel (and other variable) costs of about \$0.05/kWh. Although SFV pricing protects utility profits from erosion when sales decline, and does not give the utility a direct load-building incentive, this type of pricing deviates from the economic principle that rates should, as a general matter, be based on **long-run marginal costs**. Moreover, SFV may be considered inequitable: it imposes much higher bills on low-volume users, because the fixed portion of the charge is, in effect, spread across fewer units of sale than it is for higher-volume users. In addition, SFV creates an indirect incentive for the utility to be less sensitive to increasing fixed cost investments by guaranteeing their recovery through fixed charges. Typically small users are less expensive to serve, because they are closer together (smaller homes, apartments, condos, and mobile homes), and because they require smaller wires and transformers. SFV rates also have the effect of insulating the customers' bills from their own consumption, significantly reducing the value of energy efficiency to customers. There is also a political concern about raising the total bill by such a significant percentage (44 percent in the example in Figure 19-2) for low-usage customers.

SFV rates favor the largest residential users, at the expense of smaller users. In this way, they operate like declining block rates. Large residential users are typically those who have space conditioning loads—heating

Figure 19-2



and cooling. Those loads are the most expensive to serve, because they are so weather-sensitive, requiring investment in seldom-used generation, transmission, and distribution capacity. Compared with inverted-block rates, an SFV rate masks the full cost of serving space conditioning loads.

19.5. Incentive/Penalty Mechanisms

Some commissions have simply created profit incentives or penalty mechanisms for energy efficiency. If the utility achieves or exceeds its target, it receives a financial reward, typically a percentage of the energy cost savings that consumers receive. If it falls short of the target, it may be subject to a penalty.

Early efforts at providing incentives in this manner rewarded the utility with a percentage of the spending on energy efficiency; however, this approach rewards spending rather than efficiency gains. A few states have tried granting a bonus to the return on equity in efficiency investment, but have found this encourages gold-plating, not maximization of cost-effective investment. Most commissions that have incentive structures have abandoned the percent of budget approach in favor of a shared net benefits approach, in which the utility garners some share of the underlying real value of the efficiency programs.

States may also consider incentive/penalty mechanisms for other utility functions, including service quality as discussed in Chapter 22.

For more information:

Harrington et al., *Energy Efficiency Policy Toolkit*.

Migden-Ostrander, J., Watson, B., Lamont, D., & Sedano, R. (2014, July). *Decoupling Case Studies: Revenue Regulation Implementation in Six States*.

Montpelier, VT: The Regulatory Assistance Project. Retrieved from <http://www.raponline.org/document/download/id/7209>

Morgan, P. (2013, February). *A Decade of Decoupling for US Electric Utilities: Rate Impacts, Designs, and Observations*. Graceful Systems LLC. Retrieved from <http://www.raponline.org/document/download/id/6356>

The Regulatory Assistance Project. (2011). *Revenue Regulation & Decoupling: A Guide to Theory and Application*. Retrieved from <http://www.raponline.org/document/download/id/902>

20. Regulatory Treatment of Environmental Compliance Costs

Despite growing renewable generation, natural gas and coal are still burned to produce over half of the United States' electricity.⁹⁶ Burning either of these fossil fuels emits or discharges pollutants that are currently or will potentially be regulated under various state and federal environmental protection statutes.⁹⁷ For 100 years of utility regulation, regulatory goals have included ensuring electric system reliability, promoting resource adequacy, and pursuing lower energy bills for ratepayers. For nearly half a century, the EPA has been developing regulations to protect the environment. In the 21st century, utility regulatory commissions and energy planning bodies will find it increasingly necessary to work with environmental regulators and utilities to find ways to meet these traditional goals and to achieve affordable environmental compliance at the same time.⁹⁸ The role of utility regulators in environmental regulation is narrowly conceived as the economic evaluation of what investments in pollution control are appropriate, and when older generating resources should be retired in favor of newer units with improved pollution technology or inherently less environmental impact. More broadly, it can be viewed as an evaluation of *all* costs and benefits of varied energy resource combinations, all of which provide reliable and safe service with different environmental footprint, cost, and risk combinations.

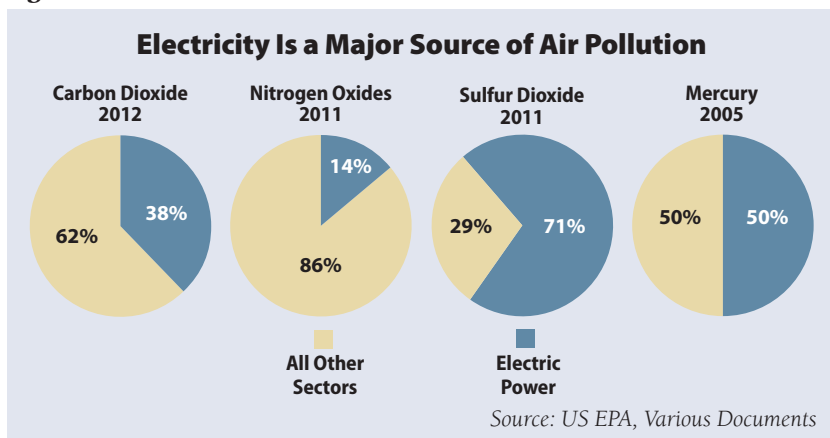
The EPA has developed a number of standards and regulations under its Clean Air Act (CAA) authority that apply to power sector sources, hardly surprising because electricity generation is a major cause of emissions, as shown in Figure 20-1. These regulations include National Ambient Air

96 According to the US Energy Information Administration, the percentage share of total US electric generation for natural gas and coal in 2014 was 27 percent and 39 percent, respectively. See: <https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3>.

97 Statutes like the Clean Air Act and Clean Water Act are examples of what are called "cooperative federalism," whereby standards are set federally, but states choose the programs and policies they will implement to meet the standards.

98 Farnsworth, D. (2011, July). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: <http://www.raponline.org/document/download/id/919>

Figure 20-1



Quality Standards (NAAQS) for pollutants like sulfur dioxide (SO₂), NO_x, particulate matter, and ground level ozone;⁹⁹ the Cross-State Air Pollution Rule; the Mercury and Air Toxics Standards (MATS); and the **Clean Power Plan** (CPP). Also, for many of these regulations, the CAA requires the EPA to periodically reassess the health and welfare effects of emissions in order to account for improved scientific knowledge, and if appropriate, to make them more stringent.

The success of these measures has been noteworthy in decoupling criteria air pollution from economic, energy consumption, and population growth, as illustrated in Figure 20-2. Environmental rules tend to be cost-effective because of many beneficial mitigation measures prompted by the rules.¹⁰⁰

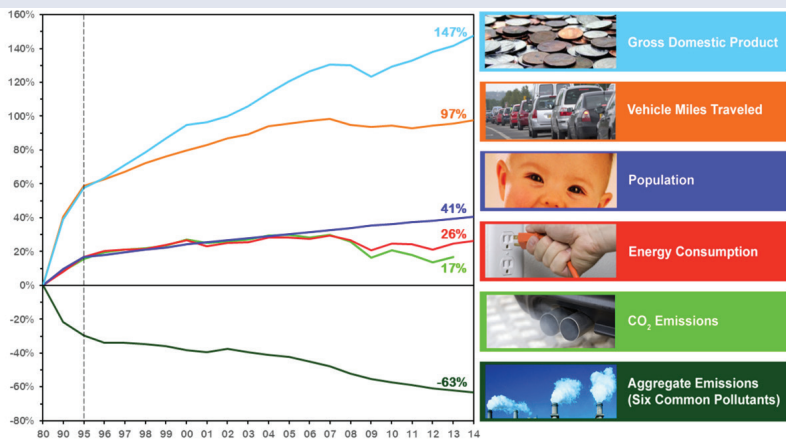
The EPA has also developed regulations under its Clean Water Act (CWA) and Resource Conservation and Recovery Act (RCRA) authority. These regulations focus on cooling water systems under the CWA, effluent discharges under the CWA, and disposal of coal ash and coal combustion residuals as solid wastes under the RCRA.

99 The CAA requires the EPA to set, and periodically update, NAAQS for pollutants considered harmful to public health and the environment: sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter, ground-level ozone, carbon monoxide, and lead. In March 2016, the EPA identified new “non-attainment” areas for its 2010 one-hour SO₂ NAAQS, including counties in Texas, Illinois, Indiana, Louisiana, Maryland, Michigan, Missouri, and Oklahoma.

100 Wax, D. (2013). EPA’s Benefits Greatly Outweigh Costs, According to OMB Report. *Appalachian Voices*. Retrieved from: <http://appvoices.org/2013/05/15/epa%E2%80%99s-benefits-greatly-outweigh-costs-according-to-omb-report/>

Figure 20-2

Comparison of Growth Areas and Emissions, 1980 to 2014



Note: CO₂ emissions estimate through 2013. Source: 2014 US Greenhouse Gas Inventory Report. Gross Domestic Product: Bureau of Economic Analysis. Vehicle Miles Traveled: Federal Highway Administration. Population: Census Bureau. Energy Consumption: Dept. of Energy, Energy Information Administration. Aggregate Emissions: EPA Clearinghouse for Inventories and Emissions Factors

This chapter briefly discusses how regulatory commissions treat environmental compliance costs and how working with environmental and energy planning bodies can help minimize those costs.

In general, regulatory commissions have allowed utilities to recover the costs of required pollution control equipment, but there are a few exceptions. In particular, if a commission finds that a utility has been imprudent, it may disallow a portion of these costs.

20.1. Key Regulated Air Emissions

20.1.1. Sulfur Dioxide

SO₂ is emitted by burning fuels containing sulfur, primarily coal. The most common SO₂ controls are flue-gas desulfurization (often called “scrubbers”), dry sorbent injection, and fuel switching to coal with a lower sulfur content or to natural gas.¹⁰¹ SO₂ is regulated primarily under the federal Acid Rain Program of the CAA, the first large-scale use of cap-and-trade.

101 See Farnsworth, *Preparing for EPA Regulations*, at note 19.

20.1.2. Nitrogen Oxides

Emissions of smog-producing oxides of nitrogen have been reduced by over 60 percent since regulations took effect in 1998 in California, the northeast, and the mid-Atlantic states. Coal, natural gas, and oil-fired power plants reduce nitrogen oxides (NO_x) emissions most often through combustion modification and end-of-stack controls.¹⁰² There are several effective NO_x control technologies, including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), low-NO_x burners, and overfire air systems.¹⁰³

20.1.3. Particulate Matter

Power plants that burn coal, oil, or biomass (e.g., forest residue, mill waste, and wood chips) emit small particles of solid matter during the combustion process. Although current regulations govern particles down to 2.5 microns in diameter, there is evidence that even smaller particulates have adverse health effects, and these ultrafine particulates may be regulated in the future. Power plant particulates are often controlled through end-of-stack controls. Particulate matter can be removed with electrostatic precipitators, fabric filters (also known as baghouses), wet scrubbers, and mechanical collectors.¹⁰⁴

20.1.4. Ozone

Ground-level ozone is produced in the atmosphere by a chemical reaction between NO_x and volatile organic compounds (VOCs) in the presence of sunlight. It is the major component of “smog,” and numerous public health studies over the last three decades have established that “ozone and fine particle pollution cause thousands of premature deaths and illnesses each year. . . .”¹⁰⁵ Ground-level ozone also impairs plant growth, and thus impacts agricultural and forest productivity as well as human health.

20.1.5. Regional Haze

The CAA includes provisions to protect public health, but also public welfare, one element of which is visibility. The CAA authorizes the EPA to regulate regional haze, and to implement a federal regional haze plan if

102 “End-of-stack” controls are post-combustion devices and processes that reduce the amount of regulated pollutants that are ultimately emitted from a facility’s smokestack.

103 See Farnsworth, *Preparing for EPA Regulations*, at note 19.

104 See Farnsworth, *Preparing for EPA Regulations*, Appendix 2: Controls for Criteria and Toxic Air Pollutants

105 U.S. EPA (2011, June 27). Air Transport Rule Information Page. Retrieved from: <http://www.epa.gov/airtransport>.

states choose not to submit or enforce acceptable state regional haze plans. Accordingly, utility regulators should ensure that regional haze considerations are incorporated into utility resource planning.

20.1.6. Mercury and Air Toxics

In February 2012, the EPA published final emissions standards for toxic air contaminants emitted from coal- and oil-fired **electricity generating units** (EGUs). Known as MATS, this regulation covers emissions of mercury, arsenic, other metals, acid gases, and organic toxins like dioxins.¹⁰⁶ Air toxic emissions can often be reduced as a co-benefit of technologies designed to reduce SO₂ emissions. Where this is not sufficient, pollutant-specific technologies (like sorbent injection) can often be applied.

20.1.7. Interstate Transport of Air Pollution

The Cross-State Air Pollution Rule (CSAPR) requires 28 states in the eastern half of the United States to reduce emissions (including those from power plants) that travel across state lines and limit the ability of other states to meet federal ground-level ozone and fine particle pollution standards. CSAPR relies on cap-and-trade mechanisms (discussed below) to reduce SO₂ and NO_x emissions in order to enable downwind states to attain air quality standards.¹⁰⁷

20.1.8. Carbon Dioxide and the EPA's Clean Power Plan

The CPP requires states to develop their own implementation plans setting out the manner in which their EGUs will meet required federal CO₂ emissions limits. The rule provides states with the choice of framing their emissions limits as a rate—measured in pounds emitted per MWh of generation (the “rate-based” approach)—or in total tons of CO₂ emitted (the “mass-based” approach). The CPP also allows emitters to trade emissions rate credits (under the rate-based approach) or emissions allowances (under the mass-based approach) to achieve compliance. States are required to submit their plans to the EPA showing how they will meet the goals; the EPA must approve states’ plans or impose its own federal plan.¹⁰⁸ Utility regulators will

106 Mercury and Air Toxics Standards, Final Rule 77 FR 9304 (February 16, 2012). Supplemental Appropriate & Necessary Finding, 80 FR 75025 (December 1, 2015).

107 Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 80 Fed. Reg. 232 (December 3, 2015) (to be codified at 40 CFR Parts 52, 78, and 97).

108 It is noteworthy that at the time of this writing, the US Supreme Court has stayed enforcement of the CPP by EPA pending resolution of issues being litigated in the District of Columbia Circuit Court of Appeals. The D.C. Circuit Court’s decision will, in all likelihood, then be appealed to the Supreme Court.

have an important role in determining state CPP compliance plans, especially in identifying which power plants might be retired, which will be allowed to continue operating and how, and what if any form of trading will be embraced.

20.1.8.1. Potential Mechanisms to Assist in State CPP Compliance

Utilities operating the electricity grid generally dispatch EGUs sequentially on the basis of cost, with the lowest cost first. The same approach is likely to be used in the future, so it is important to internalize carbon compliance costs in EGUs' bids. Several mechanisms can help do so. When combined with other policies promoting less carbon-intensive resources like energy efficiency and renewable energy, the resulting price differential between carbon-intensive resources and alternative resources, when internalized, produces a strong signal to the investment community.

20.1.8.1.1. Carbon Taxes

A carbon tax as a policy instrument to reduce emissions has the advantage of providing price certainty, albeit at the expense of certainty about the degree of emissions reductions that will result. British Columbia's comprehensive carbon tax was enacted in 2008 to both increase the cost of polluting and reduce other provincial taxes:

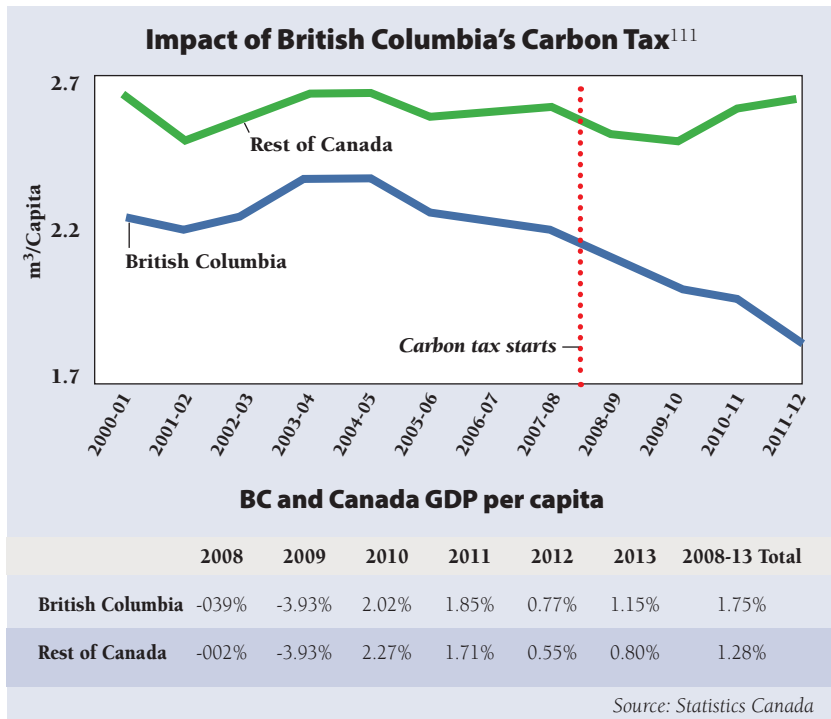
- All carbon tax revenue is "recycled" by dedicating it to reductions in other taxes;
- The carbon tax rate starts low and increases gradually;
- Distributional impacts to low-income individuals and families are addressed;
- The tax is designed to have a broad base; and
- The tax is integrated with other measures.¹⁰⁹

British Columbia's carbon tax is widely viewed as being environmentally and economically successful.¹¹⁰ Emissions in British Columbia have declined while its economy has grown faster than Canada's economy overall. Sales of petroleum fuels have declined.

109 British Columbia Ministry of Finance(2008). BC Budget and Fiscal Plan. Retrieved from: http://www.bcbudget.gov.bc.ca/2008/bfp/2008_Budget_Fiscal_Plan.pdf.

110 P.F. (2014, July 31). British Columbia's Carbon Tax: the Evidence Mounts. *The Economist*. Retrieved from: <http://www.economist.com/blogs/americasview/2014/07/british-columbia-carbon-tax>

Figure 20-3



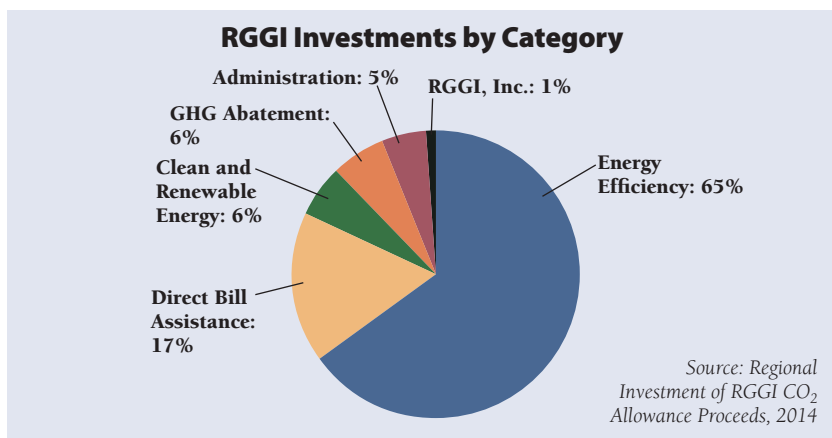
20.1.8.1.2. Capping and Trading Emissions

An emissions cap, with auction and trading of emissions rights between polluters, is a policy instrument that provides certainty about the quantity of emissions to be reduced, but offers little certainty about what price will be paid. Fortunately the model of capping emissions and allowing trading under that cap has a track record in the United States—largely owing to the experience of the Acid Rain Program—of reducing emissions faster and at far lower costs than originally projected. The European Union Emission Trading System (EU-ETS), the Regional Greenhouse Gas Initiative (RGGI), and the Western Climate Initiative (WCI) have all developed different approaches to the cap-and-trade approach, and each has used different practices in the initial allocation of emissions allowances.

The RGGI states chose to auction emissions allowances, and each state decides how to use the proceeds from its share of the sale of allowances auc-

111 Toomey, D. (2015, April 15). *How British Columbia Gained by Putting a Price on Carbon*. environment360. Retrieved from: http://e360.yale.edu/feature/how_british_columbia_gained_by_putting_a_price_on_carbon/2870/

Figure 20-4



tioned. Although their approaches have varied, in practice, states have invested the bulk of carbon allowance auction revenues in clean energy and energy efficiency (see Figure 20-4). The positive economic and environmental benefits that have resulted for state residents, businesses, and overall state economies¹¹² have led some to characterize this approach as “cap-and-invest.”

20.2. Water and Solid Waste

20.2.1. Water Intakes and Thermal Discharges

Power plants use water consumptively for steam, and also for cooling. The consumptive use may be a significant issue in drier climates. Water intake structures at EGUs can have an adverse effect on the environment by inducing mortality and morbidity in populations of aquatic organisms, either by pulling them into the cooling system or from thermal discharges of water used for cooling that can alter the ecological characteristics and habitat of the receiving water body. In 2014, the EPA finalized a rule under Section 316(b) of the CWA requiring facilities that withdraw more than two million gallons of water per day and use at least 25 percent of it for cooling purposes to take steps to mitigate these adverse impacts.¹¹³

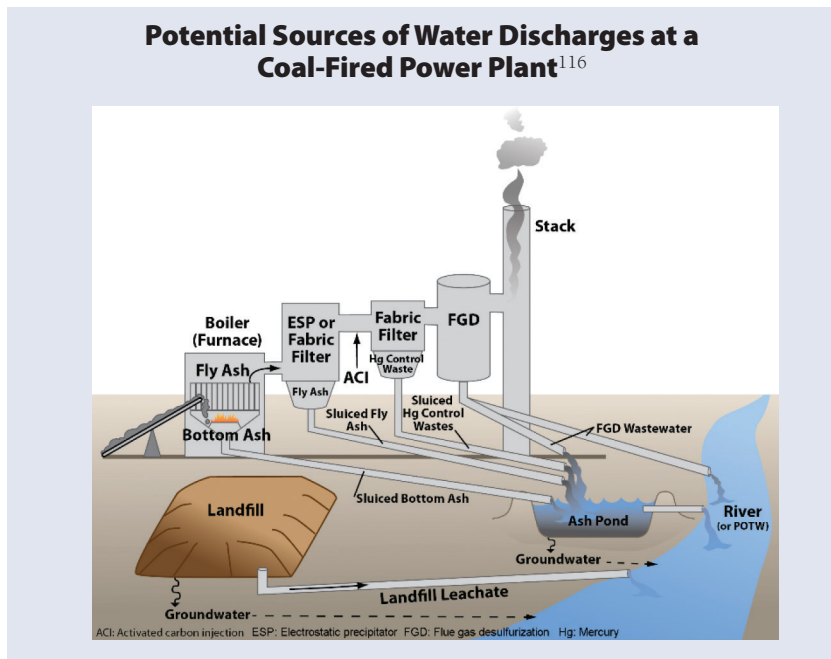
112 The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States Review of RGGI’s Second Three-Year Compliance—Period (2012-2014). Hibbard, P. J., et al. (2011, November). The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States.

113 National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities. 79 Fed. Reg. 158 (August 15, 2014)(to be codified at 40 CFR Parts 122 and 125).

20.2.2. Wastewater Discharge

In 2015, the EPA finalized its rule regarding effluent limitations and standards for discharges to reduce the amount of toxic metals, nutrients, boiler cleaning chemicals, and other pollutants that EGUs are allowed to discharge into public waters and publicly owned treatment facilities.¹¹⁴ The rule establishes requirements that will require many EGUs to make investments in process changes and in-plant controls.¹¹⁵ Figure 20-5 illustrates many of the potential sources of water discharges at a coal-fired power plant.

Figure 20-5



114 EPA. (2015, September). *Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry*. Retrieved from: https://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-final-rule-factsheet_10-01-2015.pdf

115 EPA, 2015.

116 EPA, 2015.

20.2.3. Coal Ash

In 2015, the EPA also finalized national regulations creating a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs)—or coal ash—from coal-fired power plants.¹¹⁷ CCRs are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. The rule also establishes technical requirements for CCR landfills and surface impoundments under the federal RCRA, the federal solid waste law.

20.3. Commission Treatment of Pollution Management Costs

In the past, regulatory commissions have generally allowed the cost of complying with pollution control regulations to flow through rates to consumers. Some have done so using the traditional regulatory model, considering these costs along with all others in general rate cases. Others have created separate adjustment mechanisms to flow the varying actual costs through to ratepayers between general rate cases¹¹⁸ (see discussion of adjustment clauses in Chapter 14).

In the future, regulatory commissions will likely be faced with additional requests from utilities dealing with increased environmental costs. Because environmental regulations are not all being implemented simultaneously, and because several of them are likely to be revised over time, it is crucial that regulators look at energy and environmental compliance costs in an integrated and prospective fashion—requiring utilities to consider all energy resource options not only against already-adopted (or imminent) environmental regulations, but also those likely to be adopted or modified in the future. Over the projected useful life of a power plant, for example, emissions regulations could easily be revised three to five times, elevating the risk for potentially stranded costs. Ideally, energy and environmental planning would be conducted through an integrated, multi-pollutant process.¹¹⁹ The importance of such a process may be further elevated as energy efficiency opportunities increase and the management of demand on the grid (not only supply resources) becomes more practicable.

117 Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, 80 Fed. Reg. 74 (April 17, 2015) (to be codified at 40 CFR Parts 257 and 261)

118 Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance with Public Health and Environmental Regulations*. Retrieved from: <http://www.raponline.org/document/download/id/4670>, discussion of “preapproval” and “adjustment clauses,” page 17-18.

119 The Regulatory Assistance Project. (2013, March). *Integrated, Multi-Pollutant Planning for Energy and Air Quality* (IMPEAQ). Retrieved from: <http://www.raponline.org/document/download/id/6440>

In some cases, it may not be cost-effective to continue operating existing units once additional or revised environmental regulations are in place, taking into account the remaining life of the units, the cost of retrofits, and the operating costs of the necessary pollution control equipment. Alternatives, including energy efficiency, renewable energy resources, or high-efficiency natural gas generation, may be less expensive resources than the continued operation of older power plants.

Regulators also need to be aware that environmental compliance costs may bring with them offsetting cost savings. For example, if scrubbers are installed at a coal plant to reduce sulfur emissions, the utility will avoid the need to buy SO₂ allowances, and may also enjoy savings toward MATS compliance owing to the mercury reduction co-benefits of some scrubber technologies. In addition, the utility may be able to operate the plant more of the time, thereby avoiding purchasing or generating higher-cost power from other sources. These issues can be considered in either a special purpose rate proceeding or a general rate proceeding.

Regulators will also want to exercise care in the treatment of allowances or other tradable emissions rights. Environmental compliance costs will typically be reflected in the marginal price of electricity. This is true even if utilities receive some or all of their allowances for free from the state. In organized markets, this can lead to windfall revenues, because the price of allowances is recovered in the **market clearing price** received by utilities for all power generated, even though the cost paid by the utilities for the allowances received from the state was zero.¹²⁰ This situation may differ in vertically integrated markets, but it still warrants careful commission oversight. Ensuring the proper accounting treatment of free allowances—such that the benefit provided by free allocation from the state accrues to ratepayers, not shareholders—is one example in which commission vigilance is warranted.

Market-based compliance mechanisms like cap-and-trade allow those EGUs better situated economically to invest in compliance technology to reduce emissions and then sell or trade any excess emissions reductions (i.e., any unneeded allowances) to other affected EGUs for which investing in control technologies would be a more expensive option.

Commissions will have to determine whether or not to allow utilities to invest in and recover the costs of the pollution control retrofits and emissions allowances needed to continue operating existing plants, and potentially, whether to allow them to recover the costs of any investment remaining in

120 For a more extensive treatment of carbon pricing effects in organized wholesale markets, see: Testimony of Sonny Popowski, Consumer Advocate of Pennsylvania, Subcommittee on Energy and Environment, US House Energy and Commerce Committee, March 12, 2009; see also: Cowart, R. (2008). Carbon Caps and Efficiency Resources. 33 *Vermont Law Review* 201-223.

uneconomic power plants (i.e., “stranded costs”) for units that are shut down. It is important that commissions look comprehensively at the costs of future environmental compliance for power plants, so that plants for which it is cost-effective to meet all future requirements are improved, and those for which it is not are phased out with minimal cost impact. Regulators should be prepared to critically examine expenditures, and to disallow those found to be imprudent.

For more information:

Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates: Working to Ensure Affordable Compliance with Public Health and Environmental Regulations*. Retrieved from <http://www.raonline.org/document/download/id/4670>

Jackson, S., Santen, N., Knight, P., Fields, S., Biewald, B., & Stanton, E. (2015). *Clean Power Plan Handbook*. Cambridge, MA: Synapse Energy Economics. Retrieved from <http://www.synapse-energy.com/sites/default/files/Clean-Power-Plan-Handbook.pdf>

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21. Low-Income Assistance Programs

Utilities in many states provide various forms of assistance for low-income consumers, augmenting state and federal programs. The authority of utility regulators to provide lower rates for select customers varies from state to state. In many cases, voluntary contributions or abandoned utility deposits are dedicated to low-income energy assistance. Low-income advocates often use general rate cases as a forum to seek new or augmented low-income assistance programs. A few of these are summarized here.

21.1. Rate Discounts

In many states, rates to all customers are cost-based, with no policy-driven subsidies. Other states explicitly allow or direct the commission to subsidize rates. For example, many utilities have various forms of lifeline rates, such as a discounted rate for all or for some energy used by income-qualified consumers. Rates to other customers are higher to fund this discount, and the public is considered to be better off because utility service to consumers who have the lowest incomes is more secure.

A lifeline rate should not be confused with a baseline inclining block rate, which provides every consumer with a certain amount of low-cost power, then prices usage above that at levels reflecting long-run marginal costs. An inclining block rate is cost-based, reflecting a limited supply of low-cost power and the fact that essential needs usage reflected in the first block is a stable load through the year. A lifeline rate is typically an overt discount, not based on costs at all—although if the lifeline discount applies only to a limited amount of power, it may have the effect of creating an inclining block rate design for eligible consumers in a system that otherwise has flat rates.

Some programs waive the basic monthly charge for income-eligible consumers. This has the effect of reducing bills without reducing the incentive to use electricity wisely, because the rate per kWh (or per therm) remains the same.

Figure 21-1

| Illustrative Examples of Lifeline Rates | | | |
|--|--------------------------|----------------------------|-----------------------------|
| | Non-Lifeline Rate | Lifeline Rate Block | Zero Customer Charge |
| Customer Charge | \$5.00 | \$5.00 | \$ — |
| First 500 kWh | \$0.10 | \$0.05 | \$0.10 |
| Over 500 kWh | \$0.10 | \$0.10 | \$0.10 |
| Sample Customer Bills | | | |
| 0 kWh | \$5.00 | \$5.00 | \$ — |
| 500 kWh | \$55.00 | \$30.00 | \$50.00 |
| 1,000 kWh | \$105.00 | \$80.00 | \$100.00 |
| 1,500 kWh | \$155.00 | \$130.00 | \$150.00 |

21.2. Percentage of Income Payment Programs

Percentage of income payment (PIPP) programs provide a formula for limiting the low-income customer utility bill to a limited percentage of their household income. These mechanisms require a significant and flexible amount of funding from other sources to be successful, but they are viewed as successes in the states that have implemented them.

21.3. Energy Efficiency Funding

Because low-income consumers typically cannot afford to pay even a part of the cost of energy efficiency measures, typical insulation levels and appliance efficiency are much lower in their homes. Some federal and state programs support weatherization of low-income homes, but they typically do not pay all of the costs, and there can be a lengthy waiting period that misses opportunities. Typical utility efficiency programs available to all consumers also do not pay all costs.

However, many states have combined utility and federal programs to provide full funding for installing low-income energy efficiency measures. In some states, additional programs funded partly or wholly by utilities pay for lighting conversion, refrigerator replacement, and other measures to help low-income consumers reduce their usage and their bills. In many states local community action agencies are tasked to deliver comprehensive energy efficiency service to low-income communities using federal, state, and utility-consumer funds.

21.4. Bill Assistance

Federal funds in the Low Income Home Energy Assistance Program (LIHEAP) provide direct grants for bill assistance, but in most areas these typically fall short of the need. Additional utility bill assistance programs may come from donated funds, shareholder funds, ratepayer funds, or some combination of these. Some states have dedicated utility deposits abandoned by consumers to providing low-income bill assistance. When all or a portion of the costs of bill-assistance programs is included in rates to other consumers, representatives of commercial and industrial consumers often contest whether all customer classes should share in the burden.

21.5. Payment Programs

Most utilities have budget billing programs that provide a uniform bill each month. These are typically available to all consumers; in many states, however, commissions have established specific payment programs for low-income consumers. These may include a deferral without interest, a bill limited to a percentage of income with the balance covered by bill-assistance funds, a fixed monthly credit to the bill, or other approaches.

21.6. Deposits

Utilities often require customers applying for utility service to pay a deposit related to the average or expected monthly bill, to protect the utility from non-payment. Utilities typically credit interest on this deposit to the consumer.

Nonetheless, deposits can be a burden for low-income consumers, who often seek to minimize these requirements. Some states require that deposits be waived for consumers who can establish creditworthiness, and some require that they be refunded after a year or so if a customer pays bills regularly.

21.7. Prepayment

Many utilities have experimented with prepayment meters that require customers to pay for electricity in advance. As the prepayment is used up, the customer is alerted. When the account balance falls to zero, the customer is subject to disconnection. Sometimes these are the only options offered to customers with poor payment history.

Prepayment with automatic cutoff is controversial, because it can leave customers without power at times that are unhealthy or dangerous. This risk can be reduced by barring disconnection during some times of the year and by allowing the customer to carry some deficit.

Prepayment helps the utility avoid the working capital needed to operate the utility, nearly eliminates the risk for non-payment, and nearly eliminates billing and collection expense. For this reason, it is cost-based for prepayment customers to receive a discount from the normal rate. Increasingly, utilities are also offering discounts to customers (of all income levels) who choose electronic billing and direct-draft payment of bills.

21.8. Provision for Uncollectible Accounts

In general rate cases, commissions establish a provision for uncollectible accounts, which is typically a percentage of the total utility revenue requirement. This is typically estimated on a multiyear average of actual experience. The rates for all customers are then designed to produce a little bit more than the utility's actual revenue requirement, recognizing that a small percentage of the energy delivered to consumers will not be paid for. Therefore, all consumers, not utility shareholders alone, generally bear the cost of unpaid bills.

21.9. Disconnection/Reconnection

When consumers do not pay their bills, utilities eventually disconnect their service, according to policies and procedures that regulators establish. These typically involve at least two written notices, and often require actual physical notice posted at the premises before disconnection—because postal notices are not always seen, and because disconnection can cause serious health problems for consumers who rely on electricity for medical devices.

Many states prohibit disconnection during winter months, and some have other limitations, generally designed to protect consumers from health risks.

The actual cost of sending utility personnel to the property is quite significant, particularly during nights and weekends. Commissions have generally been reluctant to impose this entire cost on low-income consumers who are in difficulty; and the reconnection fee, which is often decided along with other rate-design issues in a general rate case, seldom covers the full cost to the utility of the staff time required for disconnection and reconnection.

Smart meters, discussed more fully in Chapter 23, allow utilities to avoid these costs by remotely disconnecting and reconnecting service. Some express concern about disconnection without ultimate notice or final personal contact. Perhaps local social services staff can substitute for the utility visit at lower cost and better level of communication. Engineers concerned with safety have also expressed reservations about remote reconnection: Appliances left on during a disconnection can create fire hazards if service is reconnected when no one is present.

21.10. Access to Renewable Energy

Low-income households are less likely to be able to install solar PV or other renewable energy measures owing to lack of income, lack of access to credit, and the fact that many live in rental properties. Some states have begun to address this issue by providing for shared renewable systems, with some portion reserved for low-income households.

Shared renewables are discussed in Chapter 18. One approach for these, in which customers subscribe to a share of a common system, is to reserve a portion of each system for access by low-income households. If the shared renewables provide power at lower cost than system power, low-income customers can participate by subscription, and save money.

Shared renewables can also be priced like green power programs, in fixed-price blocks for a certain number of kWh. This kind of pricing can help low-income customers by reducing rate volatility typically associated with fuel surcharges.

Another approach has been for low-income assistance agencies or non-profit organizations to invest in renewable energy projects and dedicate the resource or the proceeds or profits to assistance for low-income consumers. Because these agencies and organizations can sometimes obtain grant funding, it may be possible to generate a long-term income source for low-income energy assistance by building renewable energy facilities.¹²¹

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The Regulatory Assistance Project & Mercados Energéticos S.A. (2002). *International Survey of Low-Income and Rural Development Programs for the Electricity Sector*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/docs/RAP_InternationalLowIncomeRuralElectricitySectorProgramSurvey_2002_07_09.pdf

See the website of the National Consumer Law Center: www.nclc.org

121 See example of the Grays Harbor County wind project at A World Institute for Sustainable Humanities (AWISH): <http://awish.net/NA/reach2.htm>

22. Service Quality Assurance

Many regulators have established standards for the reliability of service or quality of customer assistance. This is particularly important when setting up multiyear rate plans such as the PBR mechanisms discussed in Chapter 12, in which the likely result is that the utility will not be in front of the commission for an extended period.

Some of these are formal SQI programs, which penalize a utility financially if significant aspects of service fall below accepted standards. In a few cases, rewards are also available for exceeding standards. SQIs include specific measurable standards, a penalty mechanism for shortcomings, a process for review of performance, and some form of communication to consumers. These are typically initiated when a utility negotiates a multiyear rate agreement, in order to assure that utility earnings do not come at the expense of customer service quality.

More complex service quality mechanisms may be included as part of a shift from cost-based regulation to incentive-based regulation. The British “Revenue = Incentives + Innovation + Outputs” (RIIO) model is an example of this. RIIO is designed to encourage electricity distribution companies to:

- Put stakeholders at the heart of their decision-making process;
- Invest efficiently to ensure continued safe and reliable services;
- Innovate to reduce network costs for current and future consumers; and
- Play a full role in delivering a low-carbon economy and wider environmental objectives.

Figure 22-1

| Puget Sound Energy 2009 Service Quality Report | | | |
|--|-------------------------------|-------------------------|-------------------------------------|
| Key Measurement | Benchmark | 2009 Performance | Achieved |
| Customer Satisfaction Percent of customers satisfied with our Customer Access Center services, based on survey | At least 90% | 93% | <input checked="" type="checkbox"/> |
| Percent of customers satisfied with field services, based on survey | At least 90% | 95% | <input checked="" type="checkbox"/> |
| Number of complaints to the WUTC per 1,000 customers, per year | Less than 0.40 | 0.34 | <input checked="" type="checkbox"/> |
| Customer Services Percent of calls answered live within 30 seconds by our Customer Access Center | At least 75% | 78% | <input checked="" type="checkbox"/> |
| Number of disconnections per year, per customer, for non-payment | No more than 0.030 | 0.029 | <input checked="" type="checkbox"/> |
| Operations Services Frequency of non-major-storm outages per year, per customer | Less than 1.30 outages | 1.09 outages | <input checked="" type="checkbox"/> |
| Length of non-major-storm outages per year, per customer | Less than 2 hours, 16 minutes | 3 hours, 10 minutes | <input type="checkbox"/> |
| Time from customer call to arrival of field technicians in response to electric system emergencies | No more than 55 minutes | 51 minutes | <input checked="" type="checkbox"/> |
| Time from customer call to arrival of field technicians in response to natural gas emergencies | No more than 55 minutes | 33 minutes | <input checked="" type="checkbox"/> |
| Percent of service appointments kept | At least 92% | 99% | <input checked="" type="checkbox"/> |

For more information:

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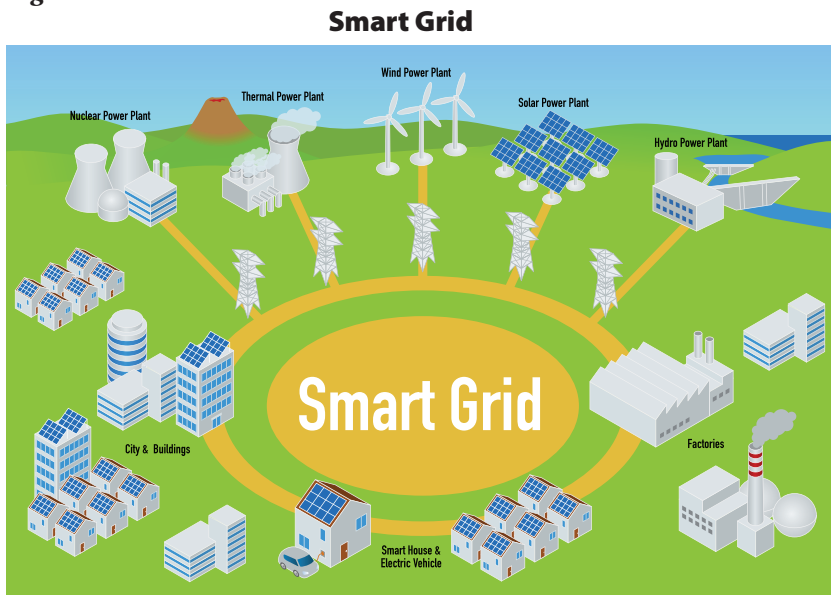
23. Smart Grid

The so-called smart grid is an important current topic in utility regulation. This guide touches on the topic, while other RAP publications address smart grid issues in more detail. Simply stated, a smart grid is an integrated system of information processing and communication applications integrated with advanced metering systems, sensors, controls, and other technologies from the bulk power system to individual end-uses that allows the electric utility to manage the flow of electricity through the grid more precisely, improve reliability, and reduce cost. The smart grid is like a network of information systems and controls that lays on top of the existing utility system for energy delivery and management. It may also enable more control and choice for customers consuming utility service, even in vertically integrated utilities.

23.1. Elements of Smart Grid

A smart grid includes multiple sources of supply, multiple points of control, and a need for extensive data exchange and communication capability.

Figure 23-1



It is expected that the smart grid will eventually:

- Enable consumers to manage their energy usage and choose the most economically efficient way to meet their energy needs;
- Allow system operators to use automation and a broad array of resources to help maintain delivery system reliability and stability;
- Help utilities to rely on the most economical and environmentally benign resources—generation, demand-side, and storage alternatives—to meet consumer demands; and
- Provide additional societal benefits, many of them unrelated to electricity service.

Smarter grids should improve reliability, increase consumer choice, and reduce the economic cost and environmental impact of the utility system.

Smart grids include several key components, including:

- **System Control.** Supervisory control and data acquisition (SCADA) systems to monitor and control power plants, transmission lines, and distribution facilities. SCADA systems are being upgraded to handle much larger amounts of data at high speed.
- **Distribution Automation.** Installation of distribution equipment that will help the grid “self-heal” from disturbances or equipment failure, without a need for human intervention at the time of the failure.
- **Smart Meters.** Historically residential electric meters have only measured consumer energy usage and displayed that data for utility meter readers. In addition to energy use, smart meters can measure voltage and in the future even residential meters may be able to measure **reactive power**, which could encourage improved **power factor**. Smart meters collect this data in short time intervals and record the data, and can communicate them electronically to the utility, the customer, and customer-designated energy service companies.
- **Meter Data Management.** All of the data from individual meters must be received, processed, and converted for billing and other purposes. For example, some utilities provide consumers with the data through information portals via the Internet.
- **Implementation Policies and Programs.** In order to achieve the goals of smart grid, utilities and their regulators must adopt policies and practices to make use of smart grid assets to enable consumers to optimize their power usage and reduce costs. These include:
 - interoperability standards that ensure that systems and products all work together without special effort by the consumer;
 - new rate designs that shift load from the highest-load hours of the year;
 - customer assistance and education;
 - automated load shedding;

- enhanced billing;
- integrating smart grid capabilities with energy efficiency programs and outage management systems; and
- and other elements.

23.2. Benefits of Smart Grid

The hypothetical benefits of smart grids are immense, but the realization of these benefits is not assured without significant commitment on the part of utilities, oversight by regulators, and supportive policies. Examples of the benefits now being achieved by some electric utilities include:

- Adapting to greater supply of variable renewable resources like wind by automatically turning water heaters or other loads on and off to keep the system in balance;
- Facilitating the charging of large numbers of electric cars to the grid without overloading existing facilities;
- Enabling new rate designs that encourage consumers to better control their energy bills by reducing usage during high-cost periods, with technology that automates response to high prices;
- Optimizing voltage and reactive power on distribution systems to reduce line losses and energy use in homes and businesses;
- Enabling frequent phase-balancing to reduce line losses;
- Quickly identifying the cause of service outages, even predicting them, and improving the speed of service restoration;
- Combining the interval data for each customer from smart meters with locational data from geographic information systems to produce “heat maps” for each transformer on a utility, thereby identifying those transformers that are undersized (and at risk for failure) or oversized (and incurring unnecessary standby losses);
- Automatic meter reading, remote disconnection and reconnection, and remote identification of power quality problems;
- Detecting and responding to problems on transmission grids in real-time;
- Adding intelligence to transformers to protect against faults and overloads; and
- Using the WiFi network installed for automated meter reading to provide community-wide free internet service

Regulators must consider whether the benefits of distinct elements of investment comprising smart grids exceed the costs. This is a complex and necessarily subjective analysis, because the value of reliability and rapid restoration of service after an outage are not easily quantified, and the environmental costs of utility operations are not precisely knowable.

The most contentious issues have centered around the costs of replacing

meters and utility system control equipment, the benefits that will actually affect customers, and the manner in which these costs are reflected in rate design. Some consumers have raised safety issues relating to radio frequencies; these issues are beyond the scope of this handbook.

Regulators have supported smart grid investments, and others have found that the benefits do not justify the costs in the specific cases before them. Utilities prepared with smart grid implementation plans when the American Reinvestment and Recovery Act was passed in 2009 were able to compete for significant federal supports for smart meter implementation and other smart grid investments. These types of investments now need to stand on their own as cost-effective investments.

23.3. Cost Allocation Issues for Smart Grid

Smart grid investments may appear to functionally replace existing equipment, but they have broader capabilities. This means that assets that may have just been allocated to customers, or just been allocated to demand, may need to reflect multiple functions in revised fair cost allocations. Traditional classification of meters as customer-related is no longer reflective of the costs and benefits of smart meters. Issues related to the allocation of smart grid costs are addressed in Chapter 9.

23.4. Smart Grid and Rate Design

Many of the benefits of smart grids can be secured without new rate designs. For example, lower line losses can be achieved through conservation voltage regulation, and reliability can be enhanced with distribution automation. These are utility-implemented improvements that provide system savings and reduce costs to serve all customers.

Some categories of benefits—particularly those associated with load response—require prices that reflect higher costs during the periods of extreme demand on the utility, and also require communications capability between the utility and the customer's premises to automate the control of end-use equipment. such as smart thermostats or customer-owned energy storage systems.

The rate design options available with a fully deployed network of smart meters, a meter data management system, and an advanced billing engine include:

- **TOU Pricing.** Rates vary by time of day, with precise rates for specific time periods set in advance
- **Critical Peak Pricing.** Rates rise sharply during specific system stress events, with advance (usually day-ahead) notice to consumers
- **Peak-Time Rebates.** Consumers who curtail usage during specific system stress events received credits; those who do not pay the regular

rate without penalty

- **Variable Peak Pricing.** Time periods are set in advance, but the rates may be changed many times per year with notice to consumers
- **Real-Time Pricing.** Prices change hourly with market conditions
- **Granular Rates.** Separate charges are applied for time-varying energy usage, time-varying peak demand, or for specific services such as advanced voltage regulation

The question of whether to make these rates optional (**opt-in**), discretionary (**opt-out**), or mandatory will be addressed by Commissions, and the result of their evaluation may be different for larger consumers than for smaller ones. For example, time-varying rates with critical peak pricing elements may be found appropriate for single-family residential customers who have central air conditioning, but perhaps not appropriate for apartment residents who have very low per-customer usage.

For more information:

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24. Regulation in the Public Interest

The role of the regulator is complex. Ensuring reliable service at reasonable cost while meeting societal goals involves balancing the interests of utility investors, energy consumers, and the entire economy. The lowest possible cost generally sacrifices important public goals, so this is generally not the result, and regulation is about managing the balance of important public goals. Longer-term interests may conflict with shorter-term interests.

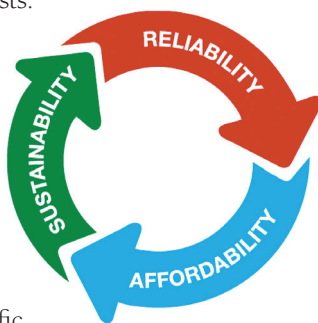
Limiting the environmental impacts of the utility system while also assuring reasonable prices, reliability, and safety is the daunting challenge that utility regulators face. Net benefits for all may still allow some to be worse off. Evolving technology provides new opportunities, but also creates new challenges.

In a general rate case, many aspects of utility service are reviewed. Often, issue-specific cases are docketed as well, to provide limited review of a particular topic. Participating in any of these cases offers opportunities to make important changes, but also obliges one to educate oneself about both technical issues and the policy framework of regulation.

Most utility regulators welcome public involvement, and are tolerant of the limited experience of new participants. In exchange, they expect respect for regulatory principles and for the dignity of the process. Regulators also expect participants to focus on facts and reasonable theories, and not simply rant about high prices.

When a major proceeding begins, all parties need to do their best to identify the issues they wish to address, and to make sure the commission agrees that those are appropriate for resolution. This avoids costly and time-consuming misunderstandings that can become very expensive and challenging if left unresolved until later in the proceeding.

Shifting some issues out of the contested rate case framework and into more collaborative approaches has proven beneficial to adapt to change and to stimulate innovation. Participants may need training and patience to be



effective in these alternative dispute resolution approaches.

The end result of progressive regulation should be a problem-solving and constructive working relationship among the various participants, and an efficient, thorough, open, and complete resolution of important issues.

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Glossary

Accumulated Deferred Income Taxes

Acronym: ADIT

An adjustment to rate base reflecting timing differences in taxes for book and ratemaking purposes. Accelerated tax depreciation is one of the drivers of ADIT.

Adjusted Test Year

A utility's investment, expense, and sales information used to allocate costs among customer classes and for setting prices for each customer class. Adjustments to historical data are made for known and measurable changes to reflect the operating and financial conditions the utility is expected to face when new rates are implemented.

Adjustment Clause

A rate adjustment mechanism implemented on a recurring and ongoing basis to recover changes in expenses or capital expenditures that occur between rate cases. The most common adjustment clause is the fuel and purchased power adjustment clause, which tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses that correct for abnormal weather conditions.

Advanced Metering Infrastructure

Acronym: AMI

The combination of smart meters, communication systems, system control and data acquisition systems, and meter data management systems that together allow for metering of customer energy usage with high temporal granularity, the communication of that information back to the utility and, optionally, to the customer, and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.

Aggregation

Bundling of multiple customers or loads to achieve economies of scale in energy markets. Aggregation also takes advantage of the diversity of loads among multiple customers and enables price risk management services to be offered to those customers.

Aggregator

A company that offers aggregation services and products.

Allocation/Cost Allocation

The assignment of utility costs to customers, customer groups, or unbundled services based on cost causation principles.

Alternating Current

Acronym: AC

Current that reverses its flow periodically. Electric utilities generate and distribute AC electricity to residential and business consumers.

Ancillary Service

One of a set of services offered in and demanded by system operators, utilities, and, in some cases, customers, which generally addresses system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves, and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services “necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”

Appliance

Any device that consumes electricity. Appliances includes lights, motors, water heaters, electronics, as well as typical household devices such as washers, dryers, dishwashers, computers, and televisions.

Average Cost

The revenue requirement of utility divided by the quantity of utility service associated with that revenue requirement, expressed as a cost per kilowatt-hour, for an electric utility, or cost per therm, for a natural gas utility.

Averch-Johnson Effect

Acronym: A-J

The incentive utilities have to overinvest in their systems if the allowed return on equity exceeds the incremental cost of attracting capital in the marketplace. This includes the potential for unnecessarily high investments in equipment, and also an incentive to retain utility ownership of power supply or other elements of rate base that could be competitively provided. The name comes from the authors of a 1962 journal article in the *American Economic Review*.

Avoided Cost

The cost not incurred by not providing an incremental unit of service. Short-run avoided cost is the incremental variable cost to produce another unit from existing facilities. Long-run avoided cost includes the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs, and line losses associated with delivering that power.

Baseload Generation/Baseload Units/Baseload Capacity/Baseload Resources

Electricity generating units that are most economically run for extended hours. Typical baseload units include coal-fired and nuclear-fueled steam generators.

Blackout

The complete cessation of the delivery of electricity to some or all of the customer loads. The most common point of failure is in the distribution system, which typically effects a relatively small subset of customers who connected “down stream” from the failure. Failures at the transmission and generation level may cause wide blackouts or even interconnection-wide failures as instability cascades through the system. When an interconnection-wide failure occurs, system operators must use cold start capable generators to bring the system back online. Also: **Rolling Blackout** – a controlled cessation of service in a series of circuits to avoid a blackout and to share the burden.

Brownout

Reductions of voltage or frequency to some or all parts of the electric grid. Brownouts occur when loads exceed available generating supply by small margins. An imbalance in load and supply caused by excessive loads will cause the frequency of the system to decline and voltages, especially on portions of the system remote from generation, to decline. Significant increases in the imbalance of load and supply during a brownout may lead to a blackout.

Budget Billing

A mechanism in which customer usage for a year is estimated, and monthly bills are established at a uniform level. The utility revisits actual consumption one or more times per year, and adjusts the monthly payment to recover any shortfall or refund any excess collection.

Busbar

A busbar is the point at which the output of a generating unit is interconnected to external equipment. A generating unit's capacity will be expressed in terms of its potential power output at the busbar. Any power consumed internally by the generator or in its control systems (station power or parasitic load) is not included in its busbar output.

Buy/Sell Arrangement

In the Buy/Sell Arrangement, a utility customer's transaction with the utility is bifurcated into two parts. In the first part, the "buy" transaction, the customer pays for its use of the distribution system through a simple, bundled rate that does not account for services provided by the customer (usually through a distributed energy resource). That rate structure could be consistent with the largely volumetric rate that is in place for most utilities today. In the second part, the "sell" transaction, the utility pays the customer for services provided by the customer. The payments could be in the form of bill credits or direct payments and based on a structure that looks very different than the rate that the customer is paying.

Capacity

The ability to generate, transport, process, or utilize power. Capacity is measured in watts, usually expressed as kilowatts (1000 watts), megawatts (1000 kilowatts), or gigawatts (1000 megawatts). Generators have rated capacities that describe the output of the generator at its busbar when operated at its maximum output at a standard ambient air temperature and altitude.

Capacity Factor

The ratio of total energy produced by a generator for a specified period to the maximum it could have produced if it had run at full capacity through the entire period, expressed as a percent.

Certificate of Public Convenience and Necessity

Acronym: CPCN

A formal determination by a regulatory body that a proposed resource, such as a power plant or transmission line, is needed to serve the public interest. It does not imply a determination that the costs incurred to acquire or build the resource are reasonable. *See: Prudence Review*

Circuit

“Circuit” generally refers to a wire that conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit that runs from a local substation or transformer to those customers. At the transmission level, the term “circuit” may also describe a pathway along which energy is transported or the number of conductors strung along that pathway.

Clean Power Plan

Acronym: CPP

A set of regulations requiring states to reduce carbon dioxide emissions from the electricity sector, adopted pursuant to the Clean Air Act. (Note: this acronym is also used for Critical Peak Pricing)

Cogeneration/Combined Heat and Power

Acronym: CHP

A method of producing power in conjunction with providing process heat to an industry, or space and/or water heat to buildings.

Coincident Peak Demand

The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, in which “system” can refer to the aggregate load of single utility or of multiple utilities in a geographic zone or interconnection, or some part thereof.

Community Solar

A solar photovoltaic installation that is shared by multiple customers. This can include specific shares owned by individual consumers, or a jointly financed, utility financed, or government financed project to which consumers subscribe in defined shares. The shared ownership model can be extended to other types of resources (wind, geothermal) as well.

Connected Load Charge

A rate design in which customers pay a fixed charge based on the capacity of their service interconnection. The bigger the capacity of the interconnection, the greater the fixed charge. Connected load charges are a way of allocating and recovering the costs of, primarily, distribution system costs.

Connection Charge

An amount to be paid by a customer to the utility, in a lump sum or in installments, for connecting the customer’s facilities to the supplier’s facilities.

Conservation Voltage Regulation

Acronym: CVR

Active control of utility distribution voltage levels to minimize total power supply cost, while ensuring adequate voltage to every customer on the distribution circuit.

Consumer-Owned Utilities

Acronym: COU

Consumer-owned utilities, including municipal utilities, electric cooperatives (co-ops), and public power districts of various types, are owned by consumers, not by private investors.

Control Area

An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to:

- Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s);
- Maintain scheduled interchange with other control areas;
- Maintain the frequency of the electric power system(s) within reasonable limits; and
- Provide sufficient generating capacity to maintain operating reserves

Cooperatives

Acronym: Co-op

See: Electric Cooperatives

Cost Allocation

Division of a utility's cost of service among its customer classes. Cost allocation is an integral part of a utility's cost of service study.

Cost of Service

Regulators use a cost of service approach to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial, and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs, and allocated based on the sales made to each class.

Cost-of-Service Study or Analysis

Acronym: COSS, COSA

An analysis performed in the context of a rate case that allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the revenue required to be collected from that class through the rates to be set in the rate case. Cost of service studies involve a great deal of judgment, and no single approach can be said to be "correct."

Critical Peak Pricing/Critical Period Pricing

Acronym: CPP

A rate design in which a limited number of hours or other periods of the year are declared by the utility, usually on a day-ahead basis, to be critical peak demand periods or when system reliability is at risk owing to generation or transmission equipment failures and during which prices charged to the customer will be extraordinarily high. The purpose of critical peak pricing is to reduce demand during the small number of hours of the year when the generation costs are at their highest. (Note: this acronym has multiple meanings)

Curtailed Service Provider

Acronym: CSP

A party that contracts with retail customers to procure the right to curtail their service under certain conditions (based on market prices or system reliability conditions) and sells that curtailment right to a utility as a service or offers it as a service in a competitive market, where it is treated as an energy resource.

Curtailment/Curtailment Service

Reduction in power supply to serve customer load in response to prices or when system reliability is threatened. Price responsive curtailment is made possible through specific curtailment programs or when offered into competitive markets as a resource. Utilities typically have a curtailment plan that can be implemented if system reliability is threatened.

Customer Charge/Basic Charge/Service Charge

A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage.

Customer Choice

The ability of a customer to choose an energy supplier. Customer choice is available in a limited number of jurisdictions where retail competition is allowed. In most instances, the choice is limited to generation supply. The delivery of that supply to the customer is typically still provided by the local monopoly utility.

Customer Class

A collection of customers sharing common usage or interconnection characteristics. Common customer classes include residential (sometimes called household), small commercial, large commercial, small industrial, large industrial, agriculture (primarily irrigation pumping), mining, and municipal lighting (street lights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads (e.g., electric vehicle charging or solar photovoltaic generation customers may be placed in their own subclass), the capacity of their interconnection (e.g., the size of commercial or residential service panel), or the voltage at which they receive service.

Customer-Sited Generation

Generation located at a customer's site. Customer-sited generation includes residential solar photovoltaic, as well as backup generating units such as are common in hospitals, hotels, and critical governmental facilities. Customer-sited generation is a form of distributed generation. Most customer-sited generation is "behind the meter," meaning it operates on the customer's side of the utility's meter, but may be interconnected to the grid, which requires it to operate synchronously with the electric system and makes it subject to certain operational and equipment requirements usually specified in an interconnection agreement or tariff. Output from customer-sited renewable generation is often accounted for under net energy metering tariffs.

Declining Block Rate

Acronym: DBR

A form of rate design in which blocks of energy usage have declining prices as the amount of usage increases. Declining block rates have largely fallen out of favor because they reward greater energy usage by the customer and do not properly reflect the increased costs associated with greater usage. They also undermine the economics of energy efficiency and renewable energy by reducing the savings a customer can achieve by reducing energy purchases from the utility.

Decoupling

See: Revenue Regulation

Default Rate/Default Service/Standard Service Offer

Acronym: SSO

The rate schedule a customer will pay if a different rate option is not affirmatively chosen. When new rate designs are offered or experimental rates are implemented, it is typical for the utility to either use an opt-in or opt-out approach for determining what rate a customer will pay. In opt-in cases, the default rate is usually the same rate the customer would have paid before the new rate design was made available. In opt-out cases, the default rate is the rate associated with the new rate design. In the context of competitive markets and retail competition, the default rate is the rate the customer will pay if a competitive alternative is not affirmatively chosen by the customer.

Default Supply

Default supply, also known as basic service and provider of last resort, provides service to those consumers who do not choose a competitive supplier, or whom the competitive market simply does not serve. Most residential and small-business consumers are served by the default supply option.

Demand

In theory, an instantaneous measurement of the rate at which power or natural gas is being consumed by a single customer, customer class, or the entirety of an electric or gas system. Demand is expressed in kilowatts or megawatts for electricity, and therms for natural gas. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is actually measured as the average rate of energy consumption over a short period of time, usually 15 minutes or an hour. For example, a 1,000-watt hair dryer run for the entirety of a 15-minute demand interval would cause a demand meter using a 15-minute demand interval to record one kilowatt of demand. If that same hair dryer were only run for 7.5 minutes, however, the metered demand would only be 0.5 kilowatt. Metering of demand requires the use of either an interval meter or an advanced smart meter.

Demand Charge

A charge paid on the basis of metered demand typically for the highest hour or 15-minute interval during a billing period. Demand charges are usually expressed in dollars per watt units, for example dollars per kilowatt (usually expressed as \$/kW). Demand charges are common for large (and sometimes small) commercial and industrial customers, but have not typically been used for residential customers because of the high cost of interval meters. The widespread deployment of smart meters would enable the use of demand charges for any customer served by those meters.

Demand Meter

A meter capable of measuring and recording a customer's demand. Demand meters include interval meters and smart meters.

Demand Response

Acronym: DR

Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response must generally be measurable and controllable to participate in wholesale markets or be relied upon by system operators.

Depreciation

The loss of value of assets, such as buildings and transmission lines, owing to age and wear.

Direct Current

Acronym: DC

An electric current that flows in one direction, with a magnitude that does not vary or that varies only slightly.

Distributed Energy Management System

Acronym: DERM

A system of control and communication allowing one or multiple parties to utilize one or more distributed energy resources to supply energy, capacity, or ancillary services to a customer, the distribution system, or a bulk power system. Sometimes DERMS, Distributed Energy Resource Management System

Distributed Energy Resources/Demand-Side Resources

Acronym: DER

Any resource or activity at or near customer loads that generates energy or reduces energy consumption. Distributed energy resources include customer-site generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency and controllable loads.

Distributed Generation

Acronym: DG

Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems, but may include utility-owned generation placed within the distribution system.

Distribution

The delivery of electricity to end-users via low-voltage electric power lines (usually 34 kV and lower).

Distribution Automation

The application of computer systems to actively manage electric distribution system functions and equipment. This includes both reliability and efficiency components.

Distribution Location Marginal Pricing

Acronym: DLMP

An unbundled rate for distribution services that introduces temporal and spatial granularity into the rate's design. This concept extends the notion of transmission-level nodal pricing, also known as locational marginal pricing, down to the distribution level.

Distribution Management System

Acronym: DMS

The combination of Supervisory Control and Data Acquisition (SCADA) systems and related logic-systems that allow a utility to control switches and other distribution system equipment.

Distribution-Only Utility

A utility that owns and operates only the distribution system. It may provide bundled service to customers by purchasing all needed energy from one or more other suppliers, or may require that customers make separate arrangements for energy supply. See: Vertically Integrated Utility

Distribution Resource Planning

See: *Integrated Distribution System Planning*

Distribution System

That portion of the electric system used to distribute energy to customers. The distribution system is usually distinguished from the transmission system on the basis of voltage and function. After energy is received from a generator's busbar, its voltage is stepped up to very high levels where it is transported by the transmission system. Transmission system components carry energy at voltages as high as 758 kV or higher and as low as 115 kV or lower.

Distribution System Operator

Acronym: DSO

The entity that operates the distribution portion of an electric system. In the case of a vertically integrated utility, this entity would also provide generation and transmission services. In many restructured markets, the distribution system operator only provides delivery services and may provide only limited energy services as a provider of last resort.

Dynamic Pricing

Dynamic pricing creates changing prices for electricity that reflect actual wholesale electric market conditions. Examples of dynamic pricing include critical period pricing and real-time rates.

Electric Cooperative

Acronym: Co-op

Electric cooperatives are consumer-owned utilities that are owned by the electric consumer members. They are controlled by a member-elected board, which includes business customers. Some coops are regulated by state utility commissions, and some are not. Most co-ops were formed in the years following the Great Depression, to extend electric service to remote areas that investor-owned utilities were unwilling to serve; there are also some urban cooperatives.

Energy

A unit of demand consumed over a period of time. Energy is expressed in watt-time units, in which the time units are usually one hour, such as one kilowatt-hour, one megawatt-hour, and so on. An appliance placing one kilowatt of demand (1 kW) on the system for one hour will consume one kilowatt-hour (1 kWh) of energy.

Energy Audit

A program in which an auditor inspects a home or business and suggests ways energy can be saved.

Energy Charge

A price component based on energy consumed. Energy charges are typically expressed in dollars per watt-hours, such as \$/kWh or \$/MWh.

Energy Efficiency

Acronym: EE

The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher efficiency boilers and air conditioners, increased building insulation, more efficient lighting, and higher energy rated windows are all examples of energy efficiency. Energy efficiency implies a semi-permanent, longer-term reduction in the use of energy by the customer, contrasted with behavioral programs that may influence short-term usage habits.

Energy Efficiency Resource Standard or Energy Portfolio Standard

Acronym: EERS or EPS

A state requirement that utilities meet a defined portion of their future requirements through the use of energy efficiency, or a specified mix of energy resources. The obligation can be expressed as a percentage of total consumption, a percentage of annual revenues, a percentage of load growth, or more flexible standards such as “all cost-effective” energy efficiency.

Energy Imbalance Market

Acronym: EIM

A number of utilities in the western United States, with support of some state regulators, are implementing an Energy Imbalance Market that will enable exchanges of excess generation from one part of the west to address high cost or shortage of generation elsewhere in ways that may be more efficient than possible under traditional bilateral relationships.

Evaluation, Measurement, and Verification

Acronym: EM&V

The process by which the utility or regulator examines the actual results of energy efficiency programs, to determine the level of savings that are being achieved and the actual cost of the savings. EM&V is normally a part of all energy efficiency programs, and is particularly important as a component of performance-based regulation.

Externalities

Costs or benefits that are side-effects of economic activities, and are not reflected in the booked costs of the utility. Environmental impacts are the principal externalities caused by utilities (e.g., health care costs from air pollution).

Federal Energy Regulatory Commission

Acronym: FERC

The U.S. federal agency that has jurisdiction over interstate transmission systems and wholesale sales of electricity.

Fixed Charge

Any fee or charge that does not vary with consumption. Customer charges are a typical form of fixed charge. In some jurisdictions, customers are charged a connected load charge that is based on the size of their service panel or total expected maximum load. Minimum bills and straight/variable rates are additional forms of fixed charges.

Fixed Cost

An accounting term meant to denote costs that do not vary within a certain period of time, usually one year, primarily interest expense and depreciation expense. This term is often misapplied to denote costs associated with plant and equipment (which are themselves denoted “fixed assets” in accounting terms) or other utility costs that

cannot be changed in the short-run. From a regulatory and economics perspective, the concept of fixed costs is irrelevant. For purposes of regulation, all utility costs are variable in the long-run. Even the costs associated with seemingly fixed assets, such as the distribution system, are not fixed, even in the short-run. Utilities are constantly upgrading and replacing distribution facilities throughout their system as more customers are served and customer usage increases, and efforts to reduce demand can have immediate impacts on those costs.

Flat Rate

A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Frequency

The cycles per second of an alternating current electric system. In most of North America, the electric system operates at a nominal 60 cycles per second (expressed in “Hertz” as 60 Hz), whereas most of the rest of the world operates at 50 Hz. All of the generators connected to a single interconnection are required to synchronize the cycles of their own equipment to that of the entire system. From a system operator’s point of view, loads must be constantly and near-instantaneously matched to generation output in order to maintain system frequency within a narrow allowed band (e.g., 59.9 to 60.1 Hz). When the frequency exceeds allowed limits, many generators and loads are designed to automatically disconnect from the grid, which may cause serious disruptions to service, including brown outs and black outs.

Fuel and Purchased Power Adjustment Clause/Energy Cost Adjustment Clause

Acronym: FAC

An adjustment mechanism that allows utilities to recover all or part of the variation in the cost of fuel and/or purchased power from the levels assumed in a general rate case.

Fuel Cost

The cost of fuel, typically burned, used to create electricity. Fuel types include nuclear, coal, natural gas, diesel, biomass, bagasse, wood, and fuel oil. Some generators, such as wind turbines and solar photovoltaic and solar thermal generators, use no fuel or, in the case of hydroelectric generation, virtually cost-free fuel.

Generation

Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source (i.e., nuclear, coal, gas, solar, and so on) or by operational or economic characteristics (e.g., “must-run,” baseload, intermediate, peaking, intermittent, load following).

Generation and Transmission Cooperatives

Acronym: G&T

Generation and transmission cooperatives are joint action agencies that own power plants and transmission lines. G&Ts can own and manage larger, more economical sources of power than small utilities can do individually. The G&Ts may provide power management services and other services for the utilities. Such G&Ts typically generate or contract for power on behalf of many small-sized member utilities, and often require the distribution cooperatives to purchase all their supply from the G&T.

Gradualism

Gradualism is a regulatory technique used to avoid large and sudden changes in prices for consumers.

Granular Rate

The granular rate is a highly disaggregated retail rate that prices each major distribution or other service separately. Customers are billed based on the amount of each service they use.

Grid

The electric system as a whole or as a reference to the non-generation portion of the electric system.

Grid Integrated Water Heater

Acronym: GIWH

A customer-sited water heater equipped with communication and control equipment allowing it to be turned on or off by automated equipment or remotely by the customer, a third party, the distribution utility, or system operator.

High Voltage Direct Current

Acronym: HVDC

A HVDC electric power transmission system uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.

IEEE 1547

An industry standard governing the engineering and performance criteria for interconnection of customer-sited generation to the electric system. When a proposed interconnection meets certain criteria, it is usually allowed to proceed without any further review or approval of the utility, except for the execution of a required interconnection agreement, unless it would cause the total capacity of customer-sited generation on local parts of the distribution system to exceed a certain threshold or would be expected to create a situation-specific safety or reliability hazard to the system or the public. Generally, under the terms of the original IEEE 1547, a customer-sited generator would be required to automatically disconnect from the system and the customer's load in the event the grid fails or becomes unstable. An updated version, IEEE 1547.8, is currently being drafted for "smart inverters" to enable smart grid functions that allow system operators to communicate with the inverter, dispatch it for certain ancillary services, and allow the PV unit to continue to serve the customer's load in the event the grid becomes unstable or unavailable.

Incentive Regulation

See: Performance-Based Regulation (PBR)

Inclining Block Rate

Acronym: IBR

A form of rate design in which blocks of energy usage have increasing prices as the amount of usage increases. Inclining block rates appropriately, if crudely, reflect the fact that increased costs are associated with greater usage. They enhance the economics of energy efficiency and renewable energy by increasing the savings a customer can achieve by reducing energy purchases from the utility. See also: Flat

Rate, Declining Block Rate, Time-of-Use Rate, Critical Peak Pricing, Peak Time Rebate, Seasonal Rate, and Straight/Fixed Variable Rate.

Incremental Cost

A cost of study method based on the short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deployment of the next unit of capacity in the form of generation, transmission, or distribution.

Independent Power Producer

Acronym: IPP

A power plant is owned by an entity other than an electric utility. May also be referred to as a non-utility generator (NUG). See also: Merchant Power Plan

Independent System Operator

Acronym: ISO

A non-utility that has multi-utility or regional responsibility for ensuring an orderly wholesale power market, the management of transmission lines, and the dispatch of power resources to meet utility and non-utility needs. An ISO controls and operates the transmission system independently of the local utilities that serve customers. This usually includes control of the dispatch of generating units and calls on demand-side resources over the course of a day or year.

Integrated Distribution Planning

Acronym: IDP or DRP

Also known as Distribution Resource Planning. A process of planning to meet anticipated distribution system needs as customers use a growing variety of distributed energy resources. A portion of this may be adaptation to variable renewable energy, and a portion may be the use of DERs to mitigate congestion in the distribution system through demand response or dispatch of DERs.

Integrated Resource Plan

Acronym: IRP

An integrated resource plan is a long-term plan prepared by a utility to guide future energy efficiency, generation, transmission, and distribution investments. Some commissions require IRPs and review the plans.

Interconnection Agreement

A contract between a utility and a customer governing the connection and operation of customer-sited generation that is operated synchronously with the electric system.

Interruptible Tariff

A retail service tariff in which, in exchange for a fee or a discounted retail rate, the customer agrees to curtail service when called upon to do so by the entity offering the tariff, which may be the local utility or a third-party curtailment service provider. A customer may be interrupted for economic or reliability purposes, depending on the terms of the tariff.

Interval Meter

A meter capable of measuring and recording a customer's demand. An interval meter measures demand by recording the energy used over a specified interval of time, usually 15 minutes or an hour.

Intervenor

An individual, group, or institution that is officially involved in a rate case.

Investor-Owned Utility

Acronym: IOU

A privately owned electric utility owned by shareholders. Approximately 75 percent of U.S. consumers are served by IOUs.

Inverter (and Smart Inverter)

An inverter is an electronic device that converts direct current into alternating current. Photovoltaic systems and batteries provide only direct current, whereas homes and businesses and the equipment in them are operated with alternating current. Smart inverters are more sophisticated in being able to provide adjustable voltages and wave forms that may be needed to maintain grid stability over time. (Note: in some countries, the term “inverter” is used to mean any stand-alone gasoline or diesel generating unit used by customers for emergency supply of electricity)

Islanding

Placing the electric system into a configuration in which some subpart of it is electrically separated from the rest of the system but remains energized and operative. A system may be islanded to facilitate maintenance or equipment upgrades or in response to a system failure or instability. In the context of distributed generation, a single customer or small group of customers might be islanded during a system outage to be served by one or more distributed generation resources. IEEE 1547.8 governs the conditions under which islanding may occur. Microgrids may also function in an islanded manner in response to system failures or instabilities, or for economic reasons.

Kilowatt

Acronym: kW

A kilowatt is equal to 1,000 watts.

Kilowatt-hour

Acronym: kWh

A kilowatt-hour is equal to 1,000 watt-hours.

Line Transformer

A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers.

Load

The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system, or in a more specific sense to denote the customer demand at a specific point in time.

Load Factor

The ratio of average load of customer, customer class, or system to peak load during a specific period of time, expressed as a percent.

Load Following

The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given point in time. Baseload and intermediate generation is generally excluded from this category except in extraordinary circumstances.

Load Shape

The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Load-Serving Entity

Acronym: LSE

The entity that arranges energy and transmission service to serve the electrical demand and energy requirements of its end-use customers. In restructured states, such entities are not necessarily the utilities that own transmission and distribution assets.

Long-Run Marginal Costs

The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Losses/Energy Losses/Technical Losses/Non-Technical Losses

The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as “technical losses”; however, energy theft from illegal connections or tampered meters, sometimes referred to as “non-technical losses,” will also contribute to losses.

Marginal Cost

The cost of augmenting output. Short-run marginal costs are the incremental expenses associated with increasing output with existing facilities. Long-run marginal costs are the incremental capital and operating expenses associated with increasing output over time with an optimal mix of assets. Total System Long-Run Incremental Costs (TSLRIC) are the costs of building a new system in its entirety, a measure used to determine if an existing utility system is economical.

Market Clearing Price

The price at which supply and demand are in balance with respect to a particular commodity at a particular time.

Megawatt

Acronym: MW

A megawatt is equal to one million watts or 1,000 kilowatts.

Megawatt-Hour

Acronym: MWH

A megawatt-hour is equal to one million watt-hours or 1,000 kilowatt-hours.

Merchant Power Plant

A power plant owned by an entity other than a regulated utility, that sells power in a competitive market to recover both investment costs and operating costs. Some merchant power plants enter into long-term contracts with utilities or industrial customers, and others operate strictly in the short-term market for power.

Meter Data Management System

Acronym: MDMS

A computer and control system that gathers metering information from smart meters, makes it available to the utility and, optionally, to the customer. A meter data management system is part of the suite of smart technologies and is integral to the smart grid concept.

Metered Demand

The maximum demand recorded by a customer's meter. Where demand charges are used, metered demand represents the billing units used to calculate the demand charge. Metered demand may also be used to measure demand response or demand curtailment and, when coming from smart meters, to inform system operators about the status of the electric system or to inform customers about their current usage levels.

Microgrid

A localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

Minimum Bill

A rate design that charges a minimum amount of money in return for a designated amount of energy, which must be paid even if the customer's actual usage is less than that amount of energy.

Municipal Utility

Acronym: Muni

A utility owned by a unit of government and operated under the control of a publicly elected body. About 15 percent of Americans are served by Munis.

Net Energy Metering/Net Metering

Acronym: NEM

A rate design that allows a customer who has distributed generation, typically solar photovoltaic systems, to receive a bill credit at the full retail rate for energy injected into the electric system.

Non-Energy Benefits

Acronym: NEB

Benefits associated with the use of an energy resource, other than the energy itself, such as environmental and health benefits associated with energy efficiency.

Non-Utility Generator

Acronym: NUG

See: Independent Power Producer

North American Electric Reliability Corporation

Acronym: NERC

Oversees electric utility reliability standards. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada. Regional and subregional reliability organizations are subject to NERC's purview.

Off-peak

The period of time that is not on-peak. During off-peak periods, system costs are generally lower and system reliability is not an issue. Time-of-use rates typically have off-peak prices that are lower than on-peak prices.

On-peak

The period of time when customer demand is higher than normal. During on-peak periods, system costs are higher than average and reliability issues may be present. Many rate designs and utility "programs" are oriented to reducing on-peak usage.

Planning and investment decisions are often driven by expectations about the timing and magnitude peak demands during on-peak period. Time-of-use rates typically have on-peak prices that are higher than off-peak prices.

Open Access Transmission Tariff

Acronym: OATT

By federal law, the transmission system is accessible to any generator that wants to use it. This is accomplished commercially through an open access transmission tariff that sets forth prices for specific transmission services. The OATT is approved by FERC.

Opt-In

A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-in approach, customers will only be placed on the rate schedule if they actively choose that option. The opt-in approach assures that customers are placed on a rate schedule without their express permission, but will typically result in fewer customers taking the new rate.

Opt-Out

A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-out approach, customers will automatically be placed on the rate schedule unless they actively choose to stay on their existing rate schedule. The opt-out approach results in a participation rate on the new rate schedule, but risks placing customers on a rate without their knowledge and consent.

Participant Cost Test

This is a narrow measure of the value of energy efficiency investment, comparing the outlays made by the person installing the measures with the bill savings and other non-electricity benefits they receive. *See also: Total Resource Cost Test and Program Administrator Cost Test.*

Peak Demand

The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, or all of the customers in a class or all of a utility's customers during a specific period of time – hour, day, month, season, or year.

Peak Load

The maximum total demand on a utility system during a period of time.

Peaking Resource/Peaking Generation/Peaker

Generation that is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability (e.g., storage of hydrogeneration), and often has low capital costs. Peaking generation is used a limited number of hours, especially as compared to baseload generation. Peaking resources may connote non-generation resources, such as storage or demand-side resources.

Peak-Time Rebate

Acronym: PTR

A rate design that provides a bill credit to a customer who reduces usage below a baseline level during a period of high peak demand or when system reliability may be at risk. Peak-time rebates are an alternative to critical peak pricing rate designs.

Performance-Based Regulation

Acronym: PBR

Any form of alternative regulation that ties company earnings to performance on metrics set by the regulator, rather than to strict cost-recovery of invested capital and operating expenses.

Photovoltaic Systems

Acronym: PV

An electric generating system utilizing photovoltaic cells to generate electricity from sunlight. PV systems may be used in off-grid, stand-alone applications, or operated synchronously with the electric system by interconnecting through a power inverter that converts their output to system-quality AC power, which is synchronized with the AC cycles of the electric system. In the United States, synchronous operation requires the use of an inverter that meets the standards of IEEE 1547, in addition to possible additional requirements of the local utility.

Power Factor

The fraction of power actually used by a customer's electrical equipment compared to the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with system voltage.

Power Factor Adjustment

A calculation or charge on industrial or commercial customers' bills, reflecting an adjustment in billing demand based on customer's actual metered power factor.

Power Marketing Agencies

Acronym: PMA

Federal power marketing agencies were created by Congress to market power produced by federal dams. In some cases, they have also been given authority to build and own thermal power plants. These federal PMAs include the Bonneville Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration.

Power Quality

The power industry has established nominal target operating criteria for a variety of properties associated with the power flowing over the electric grid. These include frequency (expressed in kHz), voltage (V or kV), power factor, (kVa or lead/lag degrees), and harmonics. Power quality describes the degree to which the system, at any given point, is able to exhibit the target operating criteria.

Power Quality Services

Power quality services are any services or activities delivered to the electric system that are designed to improve power quality.

Price Risk Management

Techniques and strategies designed to protect a customer from experiencing unexpected or undesired increases in price. Price risk management may involve the use of financial techniques, primarily the use of financial derivatives (options and calls), or may involve the use of alternative technologies, such as energy storage or backup generation, or changes to the manner in which the customer uses energy, such as load management and manufacturing process changes.

Price Volatility

The degree to which prices change over a given period of time. Price volatility includes the magnitude, duration, and frequency of price changes. Some energy markets, notably the energy-only wholesale markets, depend on higher price volatility to function properly. Conversely, customers typically want to avoid price volatility and will engage in price risk management to avoid it.

Program Administrator (or Utility) Cost Test *Acronym: PAC or UCT*

An approach to measuring energy efficiency cost-effectiveness by measuring whether the utility revenue requirement increases or decreases as a result of the deployment of the efficiency measure. This is a narrow test, ignoring costs paid by consumers or third parties toward the measures, and also ignoring non-electricity benefits derived from the measures.

Public Utility Commission *Acronym: PUC*

The state regulatory body that determines rates for regulated utilities. Although they go by various titles, PUC and Public Service Commission are most common.

Publicly Owned Utility *Acronym: POU*

A utility owned by a governmental unit or agency, such as a municipality, a utility “district,” or a government agency. Public utilities are controlled by a voter-elected body. Most publicly owned utilities are not regulated by state regulatory commissions.

Rate Base

The net investment of a utility in property that is used to serve the public. This includes the original cost net of depreciation, adjusted by working capital, deferred taxes, and various regulatory assets. The term is often misused to describe the utility revenue requirement.

Rate Case

A proceeding, usually before a regulatory commission, involving the rates, revenues, and policies of a public utility.

Rate Design

Specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on historical or assumed usage levels. Total costs are allocated across the different price components such as customer charges, energy charges, and demand charges, and each price component is then set at the level required to generate sufficient revenues to cover those costs.

Rate Impact Test *Acronym: RIM*

A test of energy efficiency cost-effectiveness that measures the impact of increased energy efficiency on prices. It is used to determine whether all utility consumers, including non-participants (i.e., the customers not deploying the energy efficiency), will receive lower rates as a result of implementing an efficiency measure.

Reactive Power

In an energized electric system, a portion of the energy injected into the system is initially diverted into magnetic fields. In a perfectly designed and operated system, this is a one-time injection of energy, and all additional energy injected into the system is delivered to end-use appliances or lost as heat. When the system is de-energized, the energy use to create the magnetic field is recovered. In reality, some end-use appliances, typically motors as they commence operation, can draw some of their energy requirements from the magnetic field, rather than from the intended flow of energy, causing the customer's load to become out of phase with the system. Additional energy must then be injected into the system to maintain the magnetic field. This energy is termed "reactive power." Customers whose equipment draws reactive power from the system are typically charged a power factor adjustment to account for the volt-ampere reactive power (VARs) required.

Real-Time Pricing/Dynamic Pricing*Acronym: RTP*

Establishing rates that adjust as frequently as hourly, based on wholesale electricity costs or actual generation costs.

Regional Transmission Organization*Acronym: RTO*

An independent regional transmission operator and service provider established by FERC or that meets FERC's RTO criteria, including those related to independence and market size. RTOs control and manage the high-voltage flow of electricity over an area generally larger than the typical power company's service territory. Most RTOs also operate day-ahead, real-time, ancillary services and capacity markets, and conduct system planning. RTOs include PJM, ISO-New England (ISO-NE), the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), the New York ISO (NYISO), and the California ISO (CAISO).

Regulatory Compact

The term "regulatory compact" is used to describe the implicit "agreement" between a utility and the government, whereby the utility accepts an obligation to serve in return for the government's promise to approve and allow rates that will compensate the utility fully for the costs it incurs to meet that obligation. The compact actually describes the act of regulation, and there is in fact no binding agreement between a utility and the government that protects utility ownership from financial accountability.

Regulatory Lag

The lapse of time between when costs are incurred and when costs are allowed to be recovered. Most often this term refers to the period between a petition for a rate increase and formal action by a regulatory body.

Reliability

A measure of the ability of the electric system to provide continuous service to customers over time. Reliability is often measured in terms of "loss of load probability" (LOLP). The U.S.-Canadian-Mexican interconnections generally experience extremely high reliability. Reliability standards are set and maintained by the North American Electric Reliability Corporation and its regional counterparts, as well as by RTOs/ISOs and electric utilities. Compliance with reliability standards is compulsory.

**Renewable Energy Certificate/Renewable Energy Credit/ Green Certificate/
Green Tag/Tradable Renewable Certificate** *Acronym: REC*

Documentation of energy produced by a renewable energy resource. RECs can be unbundled from the energy produced and separately traded. Utilities that must comply with a renewable portfolio standard usually are required to document their compliance by possessing RECs through their own generation or by purchasing RECs from third parties, to document the production of energy from renewable resources.

Renewable Energy Zones *Acronym: REZ*

A geographic area designated by legislative or regulatory process for concentrated development of renewable energy, typically wind or geothermal. This geographic concentration allows for efficient development of required transmission lines to connect the zone to the load centers where the power will be consumed.

Renewable Portfolio/Energy Standard *Acronym: RPS or RES*

A regulatory requirement that utilities meet a specified percentage of their power supply using qualified renewable resources. See: Energy Efficiency Portfolio Standard.

Renewable Resources

Power generating facilities that use wind, solar, hydro, biomass, or other rapidly renewed or non-depleting fuel sources. In some states, qualified renewable resources exclude large hydro stations and some other types of generation.

Request for Proposal *Acronym: RFP*

The initial step in a resource procurement process in which a buyer describes the products or services sought to be purchased. An RFP is usually publicly published and serves as an invitation to potential providers to put forth the terms and conditions under which the described products or services would be provided.

Reserve Capacity/Reserve Margin/Reserves

The amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service. Traditionally a 15- to 20-percent reserve capacity was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to ten percent or even lower.

Restructured State/Restructured Market

Replacement of the traditional vertically integrated electric utility with some form of competitive market. In some cases, the generation and transmission components of service are purchased by the customer-serving distribution utility in a wholesale competitive market. In other cases, retail customers are allowed to choose their generation suppliers directly in a competitive market.

Retail Choice/Retail Competition

A restructured market in which customers are allowed to or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who, through inaction, do not choose another supplier. In Texas, there is no default service provider and all customers must make a choice.

Revenue Regulation

Revenue regulation (also known as “decoupling”) fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of an annual review of costs or a fixed inflator, or on the basis of the number of customers served. The latter approach is sometimes known as “revenue-per-customer decoupling.” The purpose is to allow utilities to recover allowed costs in volumetric prices, independent of sales volumes.

Revenue Requirement

The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.

Seasonal Rate

A rate that is higher during the peak-usage months of the year. Seasonal rates are intended to reflect differences in the underlying costs of providing service associated with different times of the year.

Secondary Voltage/Secondary

Secondary voltage normally includes only voltages under 50 kV. Secondary voltage is generally considered part of the distribution system.

Self-Generation

A generation facility dedicated to serving a particular retail customer, usually located on the customer’s premises.

Service Quality Index

Acronym: SQI

A service quality index is a mechanism established by the regulator to measure the quality of electricity service, including such factors as the frequency and duration of outages, the time required to respond to a customer inquiry, the number of regulatory complaints received, and the response time to safety-related calls. The regulator may impose a financial penalty on utilities not meeting defined goals, or may tie a portion of the allowed return to service performance.

Smart Appliance

An appliance that is capable of communicating with a customer- or utility-owned data acquisition and control system.

Smart Grid

An integrated network of sophisticated meters, computer controls, information exchange, automation, information processing, data management, and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs, and more efficient utilization of utility generation and transmission resources.

Smart Meter

An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data between the utility, optionally the customer, and the meter.

Societal Cost Test

Acronym: SCT

A measure of energy efficiency cost-effectiveness that considers all costs and all benefits of a measure, regardless of who pays or who benefits. This is the broadest cost test, and includes utility, customer, and third-party payments, energy benefits, non-energy economic benefits, plus societal benefits such as public health, economic development, and energy security.

Spinning Reserve

Any energy resource that can be called upon within a designated period of time and that system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage, or demand response. Spinning reserves may be designated by how quickly they can be made available, from instantaneously up to some short period of time.

Stakeholder Collaboratives

Many commissions have formed stakeholder collaboratives to engage utilities, state agencies, customer group representatives, environmental groups, and others in a less formal process, aimed at achieving some degree of consensus on dealing with a major issue.

Standby Service

Support service that is available, as needed, to supplement supply for a consumer, a utility system, or another utility if normally scheduled power becomes unavailable. The unavailable source may be a third-party provider or a customer-owned generator.

Straight/Fixed Variable Rate

Acronym: SFV

A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Substation

A facility with a transformer that steps voltage down from a portion of the system that transports energy in greater bulk and to which one or more circuits or customers may be connected.

Supervisory Control and Data Acquisition

Acronym: SCADA

A network of sensors, communications, and computer systems to acquire real-time data from a transmission or distribution system, showing where power is flowing, and the operating status of each component of the system. SCADA systems, in a sense, were the first application of smart grid technology.

Synchronous Interconnection/Synchronous Operation

The interconnection and operation of generation with an alternating current electric system in a manner that synchronizes the critical operating parameters of the two. Any generator connected to the electric system is required to maintain synchronicity within a narrow band in order to maintain system reliability and overall power quality

within the system. Critical measures of synchronicity include frequency, voltage, harmonics, and phase angle.

System Peak Demand

The maximum demand placed on the electric system at a single point in time. System peak demand may be a measure for an entire interconnection, for sub-regions within an interconnection, or for individual utilities or service areas.

Tariff

A listing of the rates, charges, and other terms of service for a utility customer class, as approved by the regulator.

Tariff Rider

A special tariff provision that collects a specified cost or refunds a specific consumer credit, usually over a limited period of time.

Test Year

A specific period chosen to demonstrate a utility's need for a rate increase. It may or may not include adjustments to reflect known and measurable changes in operating revenues, expenses, and rate base. A test year can be either historical or projected (often called "future" or "forecasted" test year).

Throughput Incentive

Most electricity prices recover the cost of both invested capital and operating expenses in prices that apply to each unit of consumption; some of these are fixed in the short run. If, in the short-run, variable costs to the utility rise or fall more slowly than the revenues from the change in sales, a utility will earn more if sales increase, and earn less if sales decrease.

Time-of-Use Rate/Time-Differentiated Rate

Acronym: TOU

Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences underlying costs incurred to provide service at different times of the day or week.

Total Resource Cost Test

Acronym: TRC

A measure of energy efficiency cost-effectiveness that considers all resource-related costs and resource-related benefits of the measure. This is a broad test that includes costs paid by utilities, consumers, and third parties, and considers savings in all resource areas, including electricity, other fuels, labor, and comfort.

Tracker

A rate schedule provision giving the utility company the ability to change its rates at different points in time, to recognize changes in specific costs of service items without the usual suspension period of a rate filing.

Transformer

A device that raises ("steps up") or lowers ("steps down") the voltage in an electric system. Electricity coming out of a generator is often stepped up to very high voltages (345 kW or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-

use customers. Some energy loss occurs with every voltage change. Generally, higher voltages can transport energy for longer distances with fewer energy losses.

Transmission/Transmission System

That portion of the electric system designed to carry energy in bulk. The transmission system is operated at the highest voltage of any portion of the system. It is usually designed to either connect remote generation to local distribution facilities or to interconnect two or more utility systems to facilitate exchanges of energy between systems.

Used and Useful

A determination on whether investment in utility infrastructure may be recovered in rate base, such that new rates will enable the utility to recover those costs in the future when that plant will be providing service (i.e., when it will be used and useful). In general, “used” means that the facility is actually providing service, and “useful” means that without the facility, either costs would be higher or the quality of service would be lower.

Value of Solar Tariff

Acronym: VOST

A tariff that pays for the injection of solar generated power into the electric system at a price based on its value. The valuation of solar is usually based on some or all of the following: avoided energy costs, avoided capital costs, avoided operations and maintenance expenses, avoided system losses, avoided spinning and other reserves, avoided social costs, and any other avoided costs, less any increased costs incurred on account of the presence of solar resources, such as backup resources, spinning reserves, transmission or distribution system upgrades, or other identifiable costs. A VOST is an alternative to net energy metering and non-value-based feed-in tariffs.

Variable Cost

Costs that vary with direct usage or revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. Variable cost excludes interest and depreciation expense.

Vertically Integrated Utility

A utility that owns its own generating plants (or procures power to serve all customers), transmission system, and distribution lines, providing all aspects of electric service.

Voltage Support

An ancillary service in which the provider’s equipment is used to maintain system voltage within a specified range.

Volt-Ampere Reactive

Acronym: VAR

A unit by which reactive power is expressed in an alternating current electric power system. Reactive power exists in an alternating current circuit when the current and voltage are not in phase.

Volumetric Rate

A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the purchaser.

Watt

The electric unit used to measure power, capacity, or demand. One kilowatt = 1,000 watts, one megawatt = 1,000,000 watts or 1,000 kilowatts.

Watt-Hour

The amount of energy generated or consumed with one watt of power over the course of one hour. One kilowatt-hour (kWh) equals 1,000 watts consumed or delivered for one hour. One megawatt-hour (MWh) equals 1,000 kilowatt-hours. One terawatt-hour (TWh) equals 1,000 megawatt-hours. The W is capitalized in the acronym in recognition of electrical pioneer James Watt.

Weather Normalization

An adjustment made to test year sales to remove the effects of abnormal weather. Because many end-uses, especially air conditioning and heating, vary with temperature, there is a direct correlation between weather conditions and energy sales. The objective in weather normalization is to characterize the sales a utility would have if the weather experienced during a specific period had been the same as the average weather over some sufficiently long period of time, usually 20 to 30 years.

Related Reading

Rate Design

Smart Rate Design for a Smart Future

Retrieved from: <http://www.raonline.org/document/download/id/7680>

In this paper, RAP reviews the technological developments that enable changes in how electricity is delivered and used, and sets out principles for modern rate design in this environment.

Use Great Caution in Design of Residential Demand Charges

Retrieved from: <http://www.raonline.org/document/download/id/7844>

Writing for Natural Gas & Electricity journal, Jim Lazar explored the key issues to keep in mind when considering a residential demand charge: diversity of usage, impact on low-use customers, the presence of multifamily dwellings, and time variation.

Time-Varying and Dynamic Rate Design

Retrieved from: <http://www.raonline.org/document/download/id/5131>

This report discusses important issues in the design and deployment of time-varying rates.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

Retrieved from: <http://www.raonline.org/document/download/id/6516>

This paper identifies sound practices in rate design applied around the globe using conventional metering technology.

Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs

Retrieved from: <http://www.raonline.org/document/download/id/7361>

This short policy brief reviews the primary purpose of utility regulation—enforcing the pricing discipline on monopolies that competitive markets impose on most firms—and the impact of higher customer charges and minimum bill options on customers.

Standby Rates for Combined Heat and Power Systems

Retrieved from: <http://www.raonline.org/document/download/id/7020>

This paper evaluated the efficacy of standby tariffs for combined heat and power (CHP) applications, using existing rates and terms in five states to showcase practices that demonstrate a sound application of regulatory principles and ones that could use improvement.

Rate Design as a Compliance Strategy for the EPA's Clean Power Plan

Retrieved from: <http://www.raonline.org/document/download/id/7842>

States can meet their obligations to the new Clean Power Plan (CPP) with a variety of tools, from shifting generation to developing lower-carbon resources to making energy efficiency investments. One often-overlooked way to comply with the CPP, however, is electricity rate design. A design that encourages wise use of electricity, compared with a rate that gives customers a disincentive to conserve, can represent as much as a 15 percent swing in residential customer usage. This paper offers examples of how progressive rate designs can lead to reduced emissions and thus ease the way to CPP compliance.

Designing Tariffs for Distributed Generation Customers

Retrieved from: <http://www.raonline.org/document/download/id/7983>

This paper proposes rate design principles that can be considered when structuring tariffs for DG customers, and provides examples of a variety of rate designs that are being applied in various jurisdictions, along with analysis of how these rate designs comport with the regulatory principles enunciated herein.

Distribution System Pricing with Distributed Energy Resources

Retrieved from: <http://www.raonline.org/document/download/id/8159>

This paper examines pricing issues related to the business relationship between electric distribution utilities and the owners of DERs, using specific resources as examples— including grid-integrated water heaters, ice storage air conditioners, PV systems with smart inverters, backup generators, and battery and inverter-based storage systems—to evaluate a variety of different pricing models for their economic efficiency, fairness to all customers, customer satisfaction, ability to generate stable utility revenue, and effect on bill stability.

Current Rate Designs Reflecting Smart Rate Design Concepts

Retrieved from: <http://www.raonline.org/document/download/id/7859>

This paper identifies three key rate design principles for an evolving industry and provides a few examples of utilities with currently effective rate designs that reflect these smart rate design concepts.

Integrated Resource Planning and Energy Efficiency

Recognizing the Full Value of Energy Efficiency

Retrieved from: <http://www.raonline.org/document/download/id/6739>

This paper seeks to comprehensively identify, characterize, and provide guidance regarding the quantification of the benefits provided by energy efficiency investments that save electricity. This report is meant to provide a comprehensive guide to consideration and valuation (where possible) of energy efficiency benefits. It provides a real world example that has accounted for many, but not all, of the energy efficiency benefits analyzed herein. We also provide a list of recommendations for regulators to consider when evaluating energy efficiency programs.

The Next Quantum Leap in Efficiency: 30 Percent Electric Savings in Ten Years

Retrieved from: <http://www.raonline.org/document/download/id/7944>

This report concludes that it should be possible to cost-effectively meet 30 percent of forecast electricity needs with new efficiency investments over the next ten years—a level of savings that is 50 to 100 percent greater than what leading states are acquiring today.

US Experience with Efficiency as a Transmission and Distribution System Resource

Retrieved from: <http://www.raonline.org/document/download/id/4765>

This paper summarizes US experience to date of efforts to use geographically targeted efficiency programs to defer T&D system investments. It presents several case studies and summarizes lessons learned from those initiatives. Most importantly, it concludes that targeted efficiency programs—either alone or in combination with other demand resources—clearly can be a cost-effective alternative to T&D investments.

Energy Efficiency Cost-Effectiveness Screening

Retrieved from: <http://www.raonline.org/document/download/id/6149>

This report addresses the major differences between energy efficiency cost-effectiveness tests, and is designed to help regulators recognize the important features of these broad cost-benefit tests that are frequently overlooked as the tests are applied. The authors address two elements of energy efficiency program screening that are frequently treated improperly or entirely overlooked—“other program impacts” (OPIs) and the costs of complying with environmental regulations.

Ten Pitfalls of Potential Studies

Retrieved from: <http://www.raonline.org/document/download/id/6214>

This report identifies ten significant design issues for energy efficiency potential studies, which are often mishandled, leading to flawed study results. This report provides guidance to regulators and stakeholders to help ensure that any new potential study will avoid mishandling the identified issues and will meet the study’s stated objectives.

Clean First: Aligning Power Sector Regulation with Environmental and Climate Goals

Retrieved from: <http://www.raonline.org/document/download/id/12>

Clean First is not a single policy, but rather a comprehensive suite of policies that flows from the overarching principle of aligning national power sector policies and practices with national climate and environmental policies.

Who Should Deliver Ratepayer Funded Energy Efficiency? A 2011 Update

Retrieved from: <http://www.raonline.org/document/download/id/4707>

This report describes policy options and approaches for administering ratepayer-funded electric energy efficiency programs in US states. It reviews how states have

administered energy efficiency programs to learn what lessons their experience offers, and describes the most important factors states should consider with different administrative models. State legislators and utility regulators will find this report useful as they consider ways for energy efficiency administration to be more effective, both in states that are considering the question for the first time, and in more experienced states that are implementing significant increases in their savings goals.

Incorporating Environmental Costs in Electric Rates: Working to Ensure Affordable Compliance with Public Health and Environmental Regulations

Retrieved from: <http://www.raonline.org/document/download/id/4670>

The purpose of this paper is to give utility regulators an appreciation for the breadth of issues that may cause cost impacts on fossil-fuel power plants over the coming decades. The paper begins with a brief recital of major forthcoming public health and environmental regulations for power plants. It identifies some of the costs of compliance with these existing and potential regulations. It then turns to how these costs will likely be presented to utility regulators and discusses how regulators should evaluate them

Smart Gas Investment

Retrieved from: <http://www.raonline.org/document/download/id/7722>

This article, originally published in Public Utilities Fortnightly in July 2015, describes a risk-aware approach to natural gas infrastructure, which considers the costs and risks of all complementary resources. Dr. Linvill recommends five steps to make electric system needs transparent so that the compensation provided through markets and tariffs is aligned with the value of meeting long-term system needs. These include building an intelligent grid, making needs transparent, including all resources, implementing clean-first dispatch, and improved permitting.

No Rush: A Smarter Role for Natural Gas in Clean Power Plan Compliance

Retrieved from: <http://www.raonline.org/document/download/id/7717>

This article explores the risks associated with new natural gas infrastructure and suggests that the gas fleet, rather than undergoing a large-scale build-out in anticipation of a future for which it is not well suited, could instead be optimized to complement cleaner resources. Such an approach will use gas as a genuine “bridge” to a cleaner energy future and aid the wider-scale integration of renewables into the grid.

Strategies for Energy Efficiency Finance

Retrieved from: <http://www.raonline.org/document/download/id/7451>

This paper examines strategies for a major scale-up of EE finance. The report explores the various types of EE finance programs, including examples from North America and around the world that have driven EE investment. It also lays out strategies for scaling up investment, including analysis of the market, its gaps and risks, and areas that present opportunity.

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

Retrieved from: <http://www.raonline.org/document/download/id/4537>

This paper is on the relationship between energy efficiency and avoiding line losses.

Tracking Energy Savings and Emissions Reductions From Energy Efficiency Under the Proposed Clean Power Plan

Retrieved from: <http://www.raonline.org/document/download/id/7641>

This paper focuses on tracking ownership of emissions reductions to help regulators understand how states can incorporate energy efficiency into their compliance plans. This tracking can be easily accomplished using the existing infrastructure that states and regions have already developed for renewable energy certificates (RECs). The paper also considers the implications of a new tradable instrument that EPA might use to comply with the CPP, and explores the questions of how such an instrument might be issued and tracked and whether existing systems could accommodate it.

Calculating Avoided Emissions Should Be a Standard Part of EM&V and Potential Studies

Retrieved from: <http://www.raonline.org/document/download/id/7270>

This paper explains the enormous hurdles that air pollution regulators face to quantify the impacts of energy efficiency (EE) in a way that is suitable for regulatory purposes, and suggests how EE professionals might collaborate with air pollution regulators to better understand the data needed for regulatory purposes, and modify their standard practices accordingly.

Energy Efficiency Collaboratives: Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group

Retrieved from: <http://www.raonline.org/document/download/id/7860>

Collaboratives for energy efficiency have a long and successful history and are currently used, in some form, in more than half of the US states. This guide defines and examines four different types of collaboratives based on their origin, scope, decision-making method, membership, duration, available resources, and how they interact with and influence their respective commissions. The guide also highlights common elements and conclusions on the overall effectiveness of specific characteristics of different types of collaboratives. This guide provides valuable context for decision makers as they design new or improve existing energy efficiency collaboratives

Energy Efficiency Evaluation, Measurement, and Verification

Retrieved from: <http://www.raonline.org/document/download/id/7064>

Energy efficiency evaluation, measurement, and verification (EM&V) comprises actions undertaken to assess and document the outcomes of energy efficiency activities. As part of the Global Power Best Practice Series, RAP reviews EM&V processes in China, Europe, India, and the United States.

Decoupling and Performance-Based Regulation

Revenue Regulation and Decoupling: A Guide to Theory and Application

Retrieved from: <http://www.raonline.org/document/download/id/902>

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as decoupling and the policy issues associated with its use. This guide includes a detailed case study that demonstrates the impacts of decoupling using different pricing structures (rate designs) and usage patterns.

Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know

Retrieved from: <http://www.raonline.org/document/download/id/4909>

This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

Retrieved from: <http://www.raonline.org/document/download/id/7209>

This paper examines revenue regulation, popularly known as decoupling, and the various elements of revenue regulation that can be assembled in numerous ways based on state priorities and preferences to eliminate the throughput incentive. This publication focuses on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid - Massachusetts, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented.

Performance-Based Regulation for EU Distribution System Operators

Retrieved from: <http://www.raonline.org/document/download/id/7332>

The report begins with an overview of performance-based regulation (PBR), including historical experience. It then addresses the type of mechanisms that may be appropriate for consideration in Europe. It concludes with caution about how electricity distributors may take advantage of any system that is promulgated, and suggests checks and balances as a mechanism is rolled out to ensure that societal goals are met and gaming of the mechanism is minimized.

A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations

Retrieved from: <http://www.raonline.org/document/download/id/6356>

Now covering 25 states, including 49 LDCs and 24 electric utilities, this report summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. In total, this report estimates the retail rate impacts of 1,244 decoupling mechanism adjustments since 2005.

Utility Performance Incentive Mechanisms: A Handbook for Regulators

Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms.

Renewable Energy

Teaching the “Duck” to Fly - Second Edition

Retrieved from: <http://www.raonline.org/document/download/id/7956>

This report confirms that electric grid managers and utilities can integrate high quantities of variable renewable energy, like solar and wind power, and dramatically reduce carbon emissions by using several existing, and dependable market-proven strategies and technologies in this update to the 2014 “Teaching the Duck to Fly.” This updated report identifies several new approaches that have proven effective and valuable to utilities already integrating high levels of renewable energy. These include the use of ice storage for air conditioning, controlling water and wastewater pumping, and focusing renewable energy purchases on projects that produce energy when demand is greatest, such as wind farms that peak in late afternoon.

Designing Distributed Generation Tariffs Well

Retrieved from: <http://www.raonline.org/document/download/id/6898>

This paper offers regulatory options for dealing with distributed generation, offers options regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole.

Clean Energy Keeps the Lights On

Retrieved from: <http://www.raonline.org/document/download/id/7175>

This short policy brief dispels the myth that electricity portfolios with high penetrations of variable renewable resources threaten reliability. The authors review eight recent studies commissioned by utilities, governments, and non-governmental organizations to address this issue, and find that none suggest insurmountable reliability problems.

Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar

Retrieved from: <http://www.raonline.org/document/download/id/6891>

This report examines regulatory tools and rate designs for addressing emerging issues with the expanded adoption of distributed PV and evaluates the potential effectiveness and viability of these options going forward. It offers the groundwork needed in order for regulators to explore mechanisms and ensure that utilities can collect sufficient revenues to provide reliable electric service, cover fixed costs, and balance cost equity among ratepayers—while creating a value proposition for customers to adopt distributed PV.

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge

Retrieved from: <http://www.raonline.org/document/download/id/5041>

This paper explores approaches for reducing costs to integrate wind and solar in the Western US, barriers to adopting these cost-saving measures, and possible state actions. Drawing from existing studies and experience to date, the paper identifies nine ways Western states could reduce integration costs – operational and market tools, as well as flexible demand- and supply-side resources. The paper provides an overview of these approaches; assesses costs, integration benefits, and level of certainty of these appraisals; and provides estimated timeframes to put these measures in place.

Environmental Impacts of Electricity

Quantifying the Air Quality Impacts of Energy Efficiency Policies and Programs

Retrieved from: <http://www.raonline.org/document/download/id/6680>

This report is premised on the belief that regulators should employ energy efficiency as a first step toward air quality improvement rather than as a last resort. The report provides an introduction for air quality regulators to the rationale and opportunities for using energy efficiency as an air quality improvement strategy, identifies useful data sources, and outlines four basic steps for quantifying the air quality impacts of energy efficiency policies and programs.

It's Not a SIP: Opportunities and Implications for State 111(d) Compliance Planning

Retrieved from: <http://www.raonline.org/document/download/id/7491>

This policy brief provides a side-by-side comparison of Sections 110 and 111(d) of the Clean Air Act and highlights the significant differences in requirements for state compliance plans under each section. The authors distinguish between U.S. Environmental Protection Agency's (EPA) constrained role in reviewing and approving state plans to address fine particle and ozone pollution and the flexibility afforded by Section 111(d). The authors suggest several steps states can take to maximize reward and minimize risk when taking innovative approaches to air quality planning under Section 111(d).

Integrating Energy and Environmental Policy

Retrieved from: <http://www.raonline.org/document/download/id/6352>

The purpose of this paper is to demonstrate that greater integration and coordination of energy and environmental regulation can improve both environmental and energy outcomes—as well as citizens' quality of life and economic wellbeing—and to provide some advice and guidance for moving effectively in this direction.

Carbon Markets 101: “How-to” Considerations for Regulatory Practitioners

Retrieved from: <http://www.raonline.org/document/download/id/8103>

Though ongoing legal challenges have delayed the timeline of the U.S. Clean Power Plan, states are continuing to make decisions about how to approach eventual compliance. Among these decisions is whether to pursue market-based approaches—multi-state or regional markets that trade carbon allowances or emission rate credits. This paper offers a primer for regulators, setting forth approaches and best practices for designing a carbon market that are drawn from lessons learned by more than 50 jurisdictions around the world, including the Regional Greenhouse Gas Initiative (RGGI) in the Northeastern United States.

Integrated, Multi-pollutant Planning for Energy and Air Quality (IMPEAQ)

Retrieved from: <http://www.raonline.org/document/download/id/6440>

IMPEAQ is RAP’s initial effort to develop a model process that states, local agencies, and EPA can apply to comprehensively and simultaneously reduce all air pollutants, including criteria, toxic, and greenhouse gases (GHGs). IMPEAQ seeks to identify least-cost pathways to reduce emissions of multiple pollutants by adhering to Integrated Resource Plan (IRP) principles. In doing so, IMPEAQ also seeks to minimize electric reliability impacts and other system impacts.

Transmission

Electricity Transmission: A Primer

Retrieved from: <http://www.raonline.org/document/download/id/812>

Rich Sedano and Matthew Brown have collaborated to write Electricity Transmission: A Primer. The publication was prepared for the National Council on Electric Policy, as part of work on the Transmission Siting Project. The primer is intended to help policymakers understand the physics of the transmission system, the economics of transmission, and the policies that government can and does use to influence and govern the transmission system.



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50 State Street, Suite 3
Montpelier, Vermont 05602
802-223-8199
www.raponline.org