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Electricity Regulation In the US: A Guide

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Energy solutions
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Electricity Regulation in the US: A Guide

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The Regulatory Assistance Project

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1. About This Guide to Utility Regulation[1]

Over the past 140 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 1890s, and by the 1900s they were spreading rapidly across the U.S. 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 U.S. to massive power plants, individual rooftop solar panels, and every source of electricity generation in between. Add to this the layer of pipes that run 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 continues to grow as the U.S. population expands and demand for energy increases. In 2009, the U.S. consumption of energy was 95 quadrillion Btus; this energy powers industry, transportation, residential homes, and commercial establishments throughout the country. Regulation of the utility system has also evolved over the past 140 years to ensure that the system is reliable, safe, and fairly administered. This guide will focus on electric and natural gas utility regulation in the U.S., and is meant to provide a basic understanding of the procedures used and the issues involved.

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, then provide

1 Material from two federally produced handbooks to the utility sector are used and referenced liberally throughout these pages, as are many historical works. This guide was written primarily by RAP Senior Advisor Jim Lazar, an economist with over 30 years' experience in utility regulation. The RAP review team included Rick Weston, Rich Sedano, Riley Allen, David Farnsworth, Christopher James, Edith Pike-Biegunska, Wayne Shirley, and Camille Kadoch. Editorial and publication assistance was provided by Thad Curtz and Diane Derby.

an overview of the actors, procedures, and issues involved in regulation of the electricity and gas sectors. The guide assumes that the reader has no background in the regulatory arena, and serves as a primer for new entrants. 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.

These chapters will briefly touch on most topics that affect utility regulation, but will 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 section. RAP *Issuesletters,* which provide a more comprehensive review of many topics in this guide, are available online at www.raponline.org. Also, a lengthy glossary appears at the end of this guide to explain utility-sector terms.

2. 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 they 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 land disposal are typically regulated by other government agencies. Environmental regulation is generally beyond the scope of this guide, but the pages that follow do identify ways in which utility regulation can be reformed so as to achieve, or at least not undermine, environmental policy objectives.

Two broad, fundamental principles justify governmental oversight of the utility sector. First, since a utility provides *essential services* for the well-being of society — both individuals and businesses — it is an industry *"affected with the public interest."* 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.

This section 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.

2.1. 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 *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.

2.2. 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]

While 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 would be affected by sagging wires, ruptured pipes, and other problems. The production and distribution of electricity and natural gas also have environmental and public health impacts — by the emission of pollutants, on scenic views and land uses, and even from noise — that can adversely affect the public. Generating power often produces pollution; transmission lines have both visual and physical impacts on land use; and the availability of natural gas creates opportunities to use less-polluting fuels than oil or coal.

2 John Stewart Mill, cited in Garfield and Lovejoy, *Public Utility Economics,* 1964, P. 15

3 Strictly speaking, a subsidy exists when a good or service is provided at a price that is below its long-run marginal cost — i.e., the value of the resources required to produce any more of it. While 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 — where 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, since investments in utility infrastructure are, for the most part, extremely long-lived.

Regulators may therefore impose environmental responsibilities on utilities to protect these public interests.

Because most utility consumers cannot "shop around" between 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 things 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.

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

2.3. 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, since competition and free entry into markets does not exist in natural monopolies. Regulators use a *cost of service* approach to determine a fair price for electric service, by which the aggregate costs (including a reasonable return of, and on, investment) for providing each class of service (residential, commercial, and industrial) are determined. Prices are set to recover those costs, based on the sales volumes for each class.

2.4. The So-Called Regulatory Compact

It is occasionally argued that 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 set rates that will compensate it fully for the costs it incurs to meet that obligation. This agreement is sometimes called the *regulatory compact*.

Although this phrase is often heard, there is in fact no binding agreement between a utility and the government.[4] Regulation is an exercise of the police power of the state, over an industry that is "affected with the public interest." Its need arises primarily from the monopoly characteristics of the

4 This is true in the United States. In other parts of the world, however, regulation by contract is quite common.

industry, and its general objective 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.[5]

2.5. 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 which most benefit *their* principal constituencies — shareholders and management — while meeting the requirements of the regulations.

For more details:

- NW Energy Coalition, 1993, *Plugging People Into Power*. www.raponline.org/docs/NWENERGY_PluggingPeopleIntoPower_1993.pdf
- People's Organization for Washington Energy Resources, 1982, *The People's Power Guide*.www.raponline.org/docs/WER_PeoplePowerGuide_1982.pdf
- U.S. Department of Energy 2002, *A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets.* www1.eere.energy.gov/femp/pdfs/primer.pdf

5 U.S. 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 U.S. 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), is the notion of a regulatory compact accepted.

3. 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.[6]

This section 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.

3.1. 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"[7] and that their rates and terms of service could therefore be regulated.[8] When railroads emerged in the second half of the 19th century, regulation in the U.S. became more formalized with the creation of the Federal Railroad Commission (which later became the Interstate Commerce Commission[9]) to regulate rail transportation, and later, trucking.

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3.2. 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

6 *The Regulation of Public Utilities,* Phillips, 1984, pp. 75-78.

7 The term "affected with a publick 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.

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

9 The Interstate Commerce Commission has since been dissolved.

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.[10] The "cost of service" principles of regulation (discussed in detail in Chapters 3-8 of this guide) have evolved over the 20th century from this beginning.

> ***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 ...***
>
> — U.S. Supreme Court, *Munn v. Illinois,* 94 USC 113, 126 (1877)

3.3. Restructuring and Deregulation

In about 1980, electricity prices began to rise sharply as a new era of power plants began to come into service. 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 detailed in the next section, 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, while the generation of power did not. In some cases, large-volume customers (big commercial and industrial users) were allowed to negotiate directly with 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 competitive suppliers. In both cases, the utilities retained the regulated natural monopoly of distribution.

For more details:

Bonbright, 1961, *Principles of Public Utility Rates.*
Garfield and Lovejoy, 1964, *Public Utility Economics.*
Phillips, 1984, *The Regulation of Public Utilities.*

10 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.)

4. 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 section 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.

4.1. Overview

The U.S. electric industry comprises over 3,000 public, private, and cooperative utilities, more than 1,000 independent power generators, three regional synchronized power grids, eight electric reliability councils, about 150 control-area operators, and thousands of separate engineering, economic, environmental, and land-use regulatory authorities. We'll attempt to make all of these terms meaningful.

4.1.1. Investor-Owned Utilities (IOUs)

About 75% of the U.S. 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 multi-state operations. Quite a few are organized as holding companies with multiple subsidiaries, or have sister companies controlled by a common parent corporation[11].

4.1.2. Public Power: Municipal Utilities, Utility Districts, Cooperatives

Consumer-owned utilities, COUs, serve about 25% of the U.S. population, including both 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;

11 The investor-owned utilities are organized through a trade and lobbying group called the Edison Electric Institute, or EEI. www.eei.org

- **Public utility districts** (of various types) which are utility-only government agencies, governed by a board elected by voters within the service territory;[12]
- **Cooperatives (co-ops)**, mostly in rural areas, which are private nonprofit entities governed by a board elected by the customers of the utility.[13] 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;[14]
- **Others:** A variety of Native American tribes, irrigation districts, mutual power associations, and other public and quasi-public entities provide electric service in a few parts of the U.S.

4.2. Vertically Integrated Utilities

Vertically integrated utilities are responsible for generation, transmission, and distribution of power to retail customers. In many cases, they own all or some 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.

4.3. 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 consumer-owned ones, but some are large investor-owned utilities serving in states that have undergone restructuring. These distribution-only utilities 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.

12 The public power districts and municipal utilities are organized through a trade and lobbying group called the American Public Power Association, or APPA. www.appanet.org

13 While 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.

14 The cooperatives are organized through a trade and lobbying group called the National Rural Electric Cooperative Association, or NRECA. www.nreca.org

4.4. 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.

In most cases, the U.S. 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 subject to federal regulation, federal guidance, and/or federal oversight.

The Federal Energy Regulatory Commission (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.

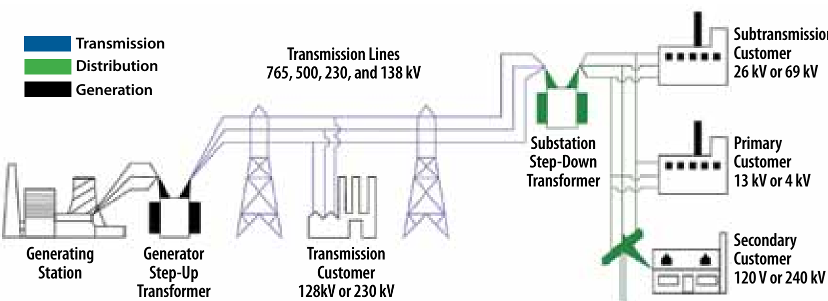
State regulators adopt construction standards for lower-voltage retail distribution facilities, quality of service standards, and the prices and terms of service for electricity provided by investor-owned utilities. They also regulate consumer-owned (i.e., cooperative and municipal) utilities in some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

4.4.1. Power Supply

Figure 4-1 shows the most essential elements of the power grid: generation, transmission, and distribution facilities.

Figure 4-1

Elements of the Grid

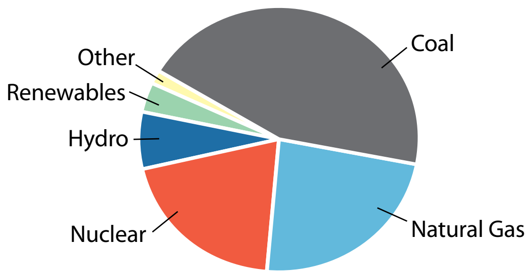


Source: US-Canada Power System Outage Task Force final report, April 2004.

Most electricity in the United States is generated by coal, natural gas, and nuclear power plants, with lesser amounts from hydropower and renewable resources such as wind and solar.[15] Licensing of nuclear and hydropower facilities is federally administered by FERC, while licensing of other types of power production — about 75% of the total — is managed at the state and local levels.

Figure 4-2:

U.S. Electricity By Fuel, 2009



Source: U.S. Energy Information Administration

4.5. Power Supply Structure and Ownership

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.

4.5.1. Federal Power Marketing Agencies

Federal *power marketing agencies* (PMAs) were created 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. The Tennessee Valley Authority 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.

15 Less than 1% of U.S. net electric generation came from oil-fired units in 2009. See Table 8.2 Electricity Net Generation: Total (All Sectors) 1949-2009, U.S. Energy Information Administration, available at: www.eia.doe.gov/emeu/aer/txt/ptb0802a.html.

4.5.2. 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 Tennessee Valley Authority and Bonneville Power Administration, and local municipal utilities are specifically exempt from general regulation by FERC.

Hundreds of companies are registered with FERC as wholesale power suppliers. While 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 re-sell it. Brokers arrange transactions, but never actually take ownership of the electricity.

4.5.3. 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.

4.5.4. Consumer-Owned Utilities (COUs).

Consumer-owned utilities, including munis, co-ops, and public power districts, are often distribution-only entities. Some procure all of their power from large investor-owned utilities, 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/or purchases from G&Ts. A few COUs own all their supply, and sell surplus power to other utilities.[16]

16 The 24 largest consumer-owned utilities are organized through a trade and lobbying group known as the Large Public Power Council, or LPPC. These utilities collectively own about 75,000 megawatts of generation. www.lppc.org

4.5.5. Retail Non-Utility Suppliers of Power

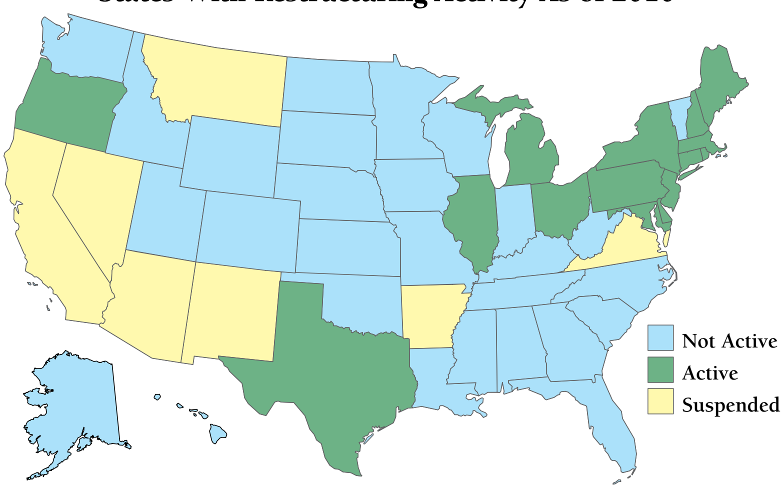
Beginning in about 1990, Britain and Wales began restructuring their utilities to allow *direct access* by letting customers choose a power supplier competitively and pay the utility only for distribution service. Under restructuring, utilities may provide combined billing for both the distribution service (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 U.S., distribution utilities perform these functions almost exclusively.)

After 1994 the British experiment was followed by some U.S. states, now including California, Illinois, Texas, 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.

These states made provisions for a *default supply* — also referred to as *basic service* — for those consumers that do not choose a competitive supplier, or whom the competitive market simply does not serve. While 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.[17]

Figure 4-3:

States With Restructuring Activity As of 2010



Source: www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

17 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.

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, while 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.

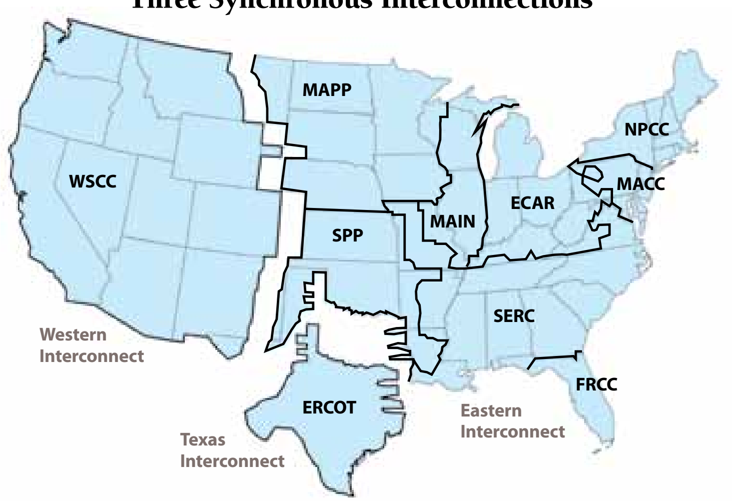
4.5.6. Transmission

Power from these various resources is distributed over high-voltage transmission networks, linked into three transmission *synchronous interconnections* (sometimes termed *interconnects*) in the continental United States. These are the Eastern Interconnection, covering east of the Rockies, excluding most of Texas, but including adjacent Canadian provinces; 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.

Because 47 states (excluding ERCOT, Hawaii, and Alaska) have interconnected transmission networks, FERC sets the rates and service standards for most bulk power transmission. More recently, FERC has been granted federal authority over the siting of transmission facilities in certain areas designated under federal law as having insufficient facilities to provide reliable service.[18]

Figure 4-4:

Three Synchronous Interconnections



Source: USDOE http://www.eia.doe.gov/electricity/chg_stru_update/chapter3.html

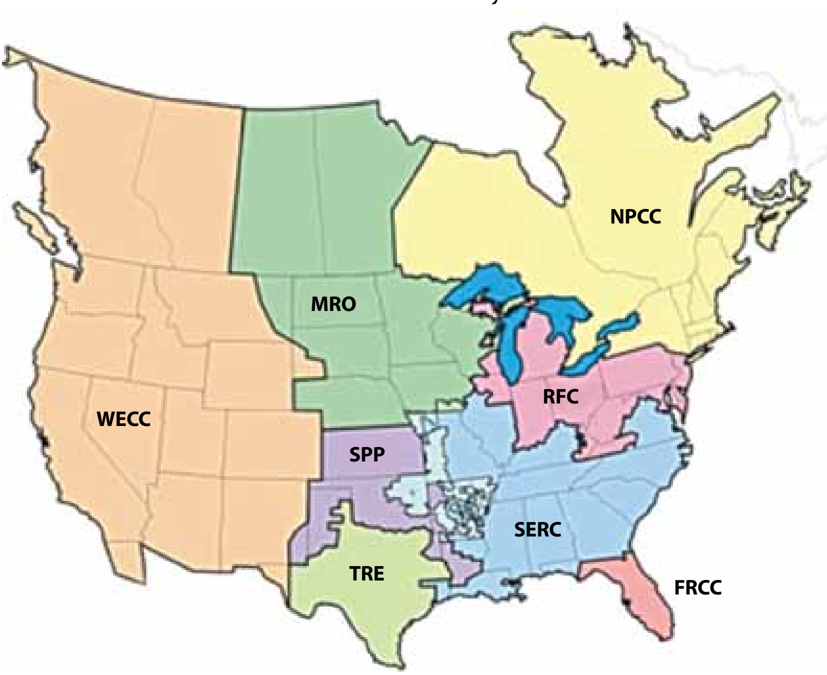
18 FERC was given limited authority in the Energy Policy Act of 2005 to step in where state siting authorities have withheld approval for transmission lines for a period of at least one year.

4.6. Managing Power Flows Over the Transmission Network

Because large batteries and pumped storage dams are very expensive, electricity cannot be stored economically — so it must generally be produced at the same time it is consumed. This 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 U.S. is divided into eight reliability planning areas, under the oversight of the North American Electric Reliability Council (NERC). NERC has adopted specific reliability standards that are legal requirements under FERC authority.

Figure 4-5:

U.S. Electric Reliability Councils



Source: North American Electric Reliability Council

4.6.1. RTOs, ISOs and Control Areas

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

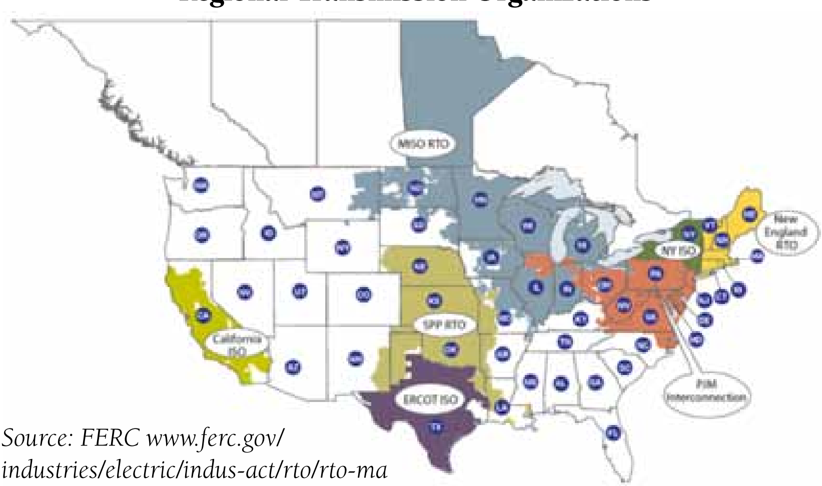
Regional transmission organizations and *independent system operators* are similar. Both are voluntary organizations established to meet FERC requirements. ISO/RTOs plan, operate, dispatch, and provide open-access transmission service under a single tariff. The ISO/RTO also purchases balancing services for the transmission system.

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.

In 1996, FERC articulated 11 criteria that ISOs would need to meet in order to receive FERC approval.[19] 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. In 1999, FERC issued Order 2000 establishing non-mandatory standards for RTOs.[20] 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 features mirrored the earlier ISO requirements. As of October 2010, seven non-profit organizations

Figure 4-6:

Regional Transmission Organizations



Source: FERC www.ferc.gov/industries/electric/indus-act/rto/rto-ma

19 Order 888, FERC Stats. & Regs., (1996).

20 Order 2000, FERC Stats. & Regs., (1999).

had been approved as either an ISO or an RTO.[21]

Some parts of the country are served by RTOs, and some by ISOs. Some are not served by either.

Some smaller 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 (only California has an ISO), and the individual control-area operators must coordinate with each other to ensure regionwide reliability of service.

Figure 4-7:

U.S. Control Area Operators

Source: USDOE; http://www.eia.doe.gov/electricity/chg_stru_update/fig8.html

4.7. Natural Gas Utilities

Most natural gas utilities do not own their own gas wells. 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

21 PJM is registered as a general Limited Liability Corporation. However, it is not profit-driven, and is structured in a way that makes it operate more like a not-for-profit entity than a for-profit corporation. For an analysis of PJM's corporate governance model see LAMBERT & IHM LLP, Principles of Corporate Governance and PJM's

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

However, unlike distribution-only electric companies, 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.

Figure 4-8:

2008 U.S. Retail Sales of Electricity By Type Of Utility

Type of Utility	Number of Utilities	Consumers	Sales (MWh)	2008 Revenue x $1000	Average $/kWh
Investor-Owned	211	94,996,996	2,229,654,009	$215,122,267	$0.096
Public	1,948	20,747,699	558,814,282	$49,178,880	$0.088
Cooperatives	938	18,167,208	392,103,539	$36,631,821	$0.093
Power Marketer	70	6,313,397	212,354,909	$25,331,745	$0.119
Total:	**3,159**	**140,225,380**	**3,392,926,739**	**$326,263,913**	**$0.096**

Source: USEIA 2008 Data

For more details:

U.S. Department of Energy, 2002, *A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets.* www1.eere.energy.gov/femp/pdfs/primer.pdf

5. The Regulatory Commission

Most state regulatory commissions and FERC follow generally similar procedures. Local regulatory bodies 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 in all cases, by:

- determining the revenue requirement;
- allocating costs (revenue burdens) among customer classes[22];
- 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 section discusses the structure and organization of the regulatory commissions. Later sections discuss how they actually operate.

5.1. Commission Structure and Organization

Most state commissions consist of three or five appointed or elected commissioners and a professional staff.[23] 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;

22 While data is reported to the USEIA in only three classes, Residential, Commercial, and Industrial, 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, while others organize business users by size or voltage. Many have separate classes for agricultural and government consumers.

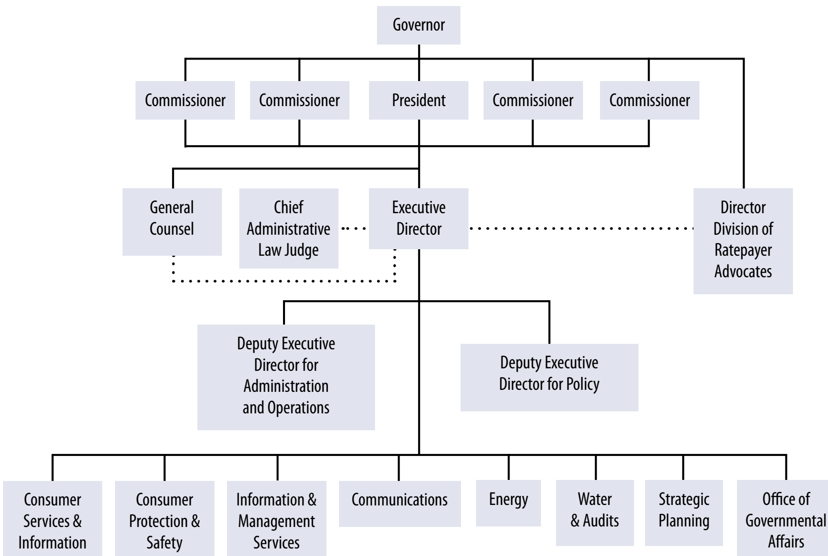
23 The state commissions and FERC are organized through the National Association of Regulatory Utility Commissioners, or NARUC. www.naruc.org

- enforcing rules and tariffs: compliance staff, attorneys; and
- providing technical assistance to the commissioners: advisory staff, attorneys.

The California PUC 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.

Figure 5-1:

California PUC Organizational Structure



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, often 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* (sometime called a *hearing examiner*), 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.

5.2. 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 some of the states with elected commissioners,[24] very strict rules 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.

5.3. Limited Powers

Commissions are limited-power regulators. Their authority is defined by law, and their decisions are subject to appeal to the state courts (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. A commission that is granted specific authority by the legislature in statute may be authorized or directed to promulgate rules. Statutes govern the affairs of state and federal agencies. The authority to make rules is delegated to agencies by the executive or legislative branch. Rules implement statutory mandates, and provide guidance on how the law is to be carried out. The rules, once adopted, have the force of law. In general, state commissions do not regulate consumer-owned utilities, but there are many exceptions.

5.4. Consumer Advocates

Most states have a designated consumer advocate. 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 the attorney general. The consumer advocate represents the public in rate proceedings, and generally has a budget for some technical staff and expert consultants. Some consumer advocates are charged with representing all customers (or at least those not otherwise adequately

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

represented), while 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. They typically do not concern themselves with environmental impacts or costs, except where those costs are internalized in the costs of providing service.[25]

5.5. COU Regulation

Consumer-owned utilities (COUs) typically have very different regulatory structures. City utilities ("municipals" or "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 utility 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 relevant body in open session.

In some states, the legislature has given the state commission full regulatory authority over cooperatives, and in a few cases, limited authority over munis.

25 The state consumer advocates are organized the National Association of State Utility Consumer Advocates, or NASUCA. www.nasuca.org

6. What Does the Regulator Actually Regulate?

Different regulators control different parts of the utility industry. Some of this is done through legislative-style rulemaking, and some through a quasi-judicial hearings process.

At the federal level, FERC has authority over hydropower licensing, interstate transmission, and wholesale power sales, although in Texas, Alaska, and Hawaii, where there are limited (or no) interstate connections[26], it only regulates licensing for construction and operation of power-producing dams.[27] FERC transmission regulation is discussed in Section 10. Nuclear power plant design, construction, operational safety and nuclear material are regulated by the Nuclear Regulatory Commission.

The state regulatory commission normally regulates all investor-owned utilities in a state. A few exceptions exist where cities have regulatory authority over IOUs (in some cases, pre-dating statehood). In most but not all states, municipal utilities and public utility districts are not subject to any economic regulation by the state utility regulator. 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.

26 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, Texas (through ERCOT) has limited interconnection 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 DC intertie is actually FERC jurisdictional, but the interconnection behind the DC intertie in Texas is not considered to be in interstate commerce.

27 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.

Federal, state, and local environmental regulators have authority over 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 which are undertaken by federal governmental agencies.[28] Additionally, federal regulators have authority over off-shore wind projects and projects under the control of federal management agencies.[29]

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

6.1. 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 Section 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.

6.2. 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

28 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.

29 For example, CapeWind, the off-shore 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 Bonneville Power Administration, also trigger review by federal regulators.

a defined set of renewable ones.[30] 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 Section 13.

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*), while others may use an integrated resource planning (IRP) process to determine whether construction of a power plant is necessary, or some combination of the two. (See Section 12 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: 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).

30 About half of the states, totaling about 75% of the nation's population, have renewable portfolio standards of some type. The definition of eligible resources varies by state. See http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm#map.

6.3. Securities Issuance

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 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 therefore normally requires approval of the regulator. Typically mergers must pass a public interest test. In some states a *no-harm* standard is imposed, while in others a *net benefit* standard must be met.

6.4. 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-market costs. 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.[31]

6.5. 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

31 Perhaps the most extraordinary of these situations was when Enron went bankrupt. Enron owned several utilities, including Northern Natural Gas and Portland General Electric. While 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.

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 implemented minimum energy efficiency standards for new homes and commercial buildings. 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 Section 18.

6.6. Utility Regulation and the Environment

Utility regulation and environmental regulation are increasingly recognized as unavoidably intertwined.[32] In most states, the utility regulator is tasked by statute as an economic regulator, leaving the enforcement of environmental laws to other agencies. However, in many states the regulator has evaluated environmental implications and risks to encourage utility investment in low-pollution alternatives such as renewable resources and energy efficiency in recognition of the large environmental impacts of 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 Section 13.) Decisions by environmental regulators also affect utility investment, as states implement plans to meet EPA standards for air, land, and water quality. Utilities may seek to recover the costs of their investments through utility regulators; or, in restructured states, they may pass along the costs of their investments through regional electricity markets. In fact, in a few states the utility regulator has a direct role in some aspects of environmental regulation.[33]

32 See: *Clean First,* Regulatory Assistance Project, www.raponline.org/docs/RAP_CleanFirst_AligningPowerSectorRegulation_2010_09_17.pdf

33 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.

7. Participation in the Rulemaking Process

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

This section 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.

7.1. Rulemaking

Commissions make two types of rules. *Procedural* rules guide how the regulatory process works; *operational* rules govern how utilities must offer service to consumers. 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.

7.2. 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. While an individual may usually participate without an attorney, requirements of the rules of procedure and evidence must nonetheless be met.

7.3. 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. These collaboratives may meet for a few months or more, then collectively recommend a change to regulations, tariffs, or policies.

7.4. Public Hearings

Utility regulators hold two types of public hearings. When a rate case is underway, the entire process of 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 Section 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 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 where 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.

7.5. Proceedings of Other Agencies Affecting Utilities

Many governmental agencies other than the utility regulator have proceedings that affect utilities. State energy offices[34] 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. 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 details:
NW Energy Coalition, 1993, *Plugging People Into Power.*
www.raponline.org/docs/NWENERGY_PluggingPeopleIntoPower_1993.pdf

34 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 www.naseo.org/.

8. Procedural Elements of US Tariff Proceedings

A commission's approved conditions, terms, and prices of utility services are published in document called a *tariff*. Regulatory commissions primarily review utility rates and these other 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, but most do not. While 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, but this is quite rare. In theory, an individual consumer submitting a formal complaint that the utility's rates were not in compliance with the requirements of law (which generally say that that rates should be "fair, just, and reasonable") could trigger a general rate review, but this almost never happens.

When an investor-owned utility 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 8 shows a typical procedural schedule.

Figure 8:

Typical Schedule for a Major Rate Case

Activity	Calendar Date	Months From Filing Date
Notice of Intent to File	15-Jan	-2
Initial Filing of Tariffs and Evidence	15-Mar	0
Discovery Period Ends	15-Jun	3
Staff and Intervenor Evidence Due	1-Jul	3.5
Rebuttal Evidence Due	1-Aug	4.5
Rebuttal Discovery Period Ends	15-Aug	5
Expert Witness Hearings	Sept 1-20	6
Public Witness Hearings	Sept 25-27	6.5
Briefs Due	1-Nov	7.5
Commission Decision	15-Dec	9

This section describes the procedural elements of a general rate proceeding: who does what and when. It is intended to help the reader understand the sequence and other formalities of a general rate case.

8.1. 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 where the utility is requesting more than a 3% increase in overall revenues, and requires 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 typically subject to less-detailed filing requirements.

8.2. 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 *intervenors,* 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.

A federal law, the Public Utility Regulatory Policies Act (PURPA), gives consumers of large electric utilities a statutory right to intervene in any proceeding relating to rates where issues addressed in PURPA (relating mostly to rate design) are considered.[35] While this law appears to guarantee a right to intervene, it does not proscribe the commission (or local regulator of a COU) from setting rules regarding intervention, or from determining whether the PURPA ratemaking standards are at issue in any given proceeding.

35 16 U.S.C. §2631 PURPA has three major parts. First, it required state commissions to "consider and determine" on a one-time basis whether certain ratemaking standards were appropriate. Second, it provides for a means of consumer intervention in the regulatory process. Third, it requires utilities to purchase power at "avoided cost" from "qualifying facilities," meaning small power plants owned by independent power producers. This last element of PURPA is the one most often identified with the Act.

8.3. 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*, 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.

8.4. 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, while exhibits contain detailed factual support, technical analysis, and numerical 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. Sometimes additional rounds of *surrebuttal* evidence — evidence in response to rebuttal evidence — are allowed.

8.5. 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.

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.

8.5.1. Expert Testimony

Persons presenting detailed technical testimony and exhibits under oath are typically called *expert witnesses*. 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 out-of-town witnesses.

Expert witnesses may be questioned as to their actual expertise on the topic. While few commissions completely dismiss evidence if a witness is found to lack genuine expertise, such a finding definitely affects the weight given to the testimony. Intervenors must make certain that their witnesses do not go beyond the scope of their expertise.

8.5.2. 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. Sometimes these are held 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's 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, 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 give the commission some discretion to craft an equitable resolution.

8.6. 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.

This gives 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 six-to-12-month hearing process.

8.7. Briefs and Closing Arguments

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

8.8. 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.

8.9. 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, but will reverse or remand a decision if they find it clearly violates some principle of law. Nearly all appeals from state commissions occur in state court, but some are appealed directly to federal courts on federal legal or constitutional grounds.

9. The Fundamentals of Rate Regulation

This section summarizes the analytical process that a regulatory commission follows in a tariff proceeding.[36]

Because commissions are supposed to set rates that provide utilities an opportunity to earn a reasonable rate of return after 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 section is 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.

9.1. 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.

36 The terms tariff *proceeding, 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.

9.1.1. Interstate System Allocation

When a utility serves more than one state, the commission conducting the proceeding must decide which facilities serve its state. 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, though 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 multi-state 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 kilowatt-hours during a period), using principles similar to those employed 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.

9.1.2. 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. While 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.

9.1.3. 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.[37] If the service territories for electricity and gas are not the same geographically, these allocations can be quite complex and controversial.

9.2. 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 9-1.

Figure 9-1:

The Basic Revenue Requirement Formula

Rate Base Investment X Rate of Return + Operating Expenses = Revenue Requirement

Each of these is described in greater detail below.

9.2.1. 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 an 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

37 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.

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).

9.2.2. 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 changes in costs that have occurred since the test year or which are reasonably expected to occur before the new rates take effect.

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, rates adopted in a rate case are estimated the first year the rates are in effect.[38]

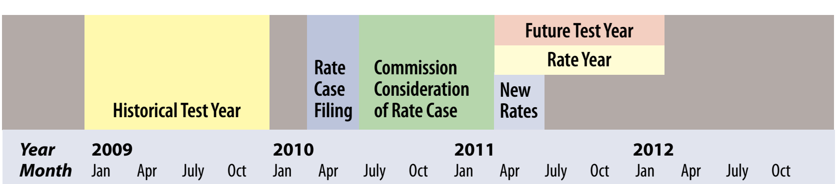
In either case, the investment in a major addition to the rate base such as a new power plant may be reflected in the test year, so that the new rates will enable the utility to recover those costs in the future when that plant will be providing service, i.e., when it will be *used and useful.* In general, *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.

Figure 9-2 depicts a typical period for a historical test year of 2009, a rate filing in the second quarter of 2010, consideration of the filing for nine months, and both a future test year and a rate year beginning in the second quarter of 2011.

Figure 9-2

Typical Period for a Historical Test Year



38 Some jurisdictions refer to these adjustments as *known and measurable changes.* They can be, naturally, a subject of debate.

9.2.1.2. Average vs. End-of-Period

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 for the year, because that more accurately reflects the entire time during which the revenues were 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.

9.2.2. 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.

Traditionally, utilities have only been allowed to add investments to rate base once they are completed and providing service to consumers. During the construction period, utilities have been allowed to accumulate an *allowance for funds used during construction* (AFUDC), so that when the construction is completed and commissioned, they earn a return not only on the money invested, but also on the carrying costs during the construction period.

When construction programs become very large, these carrying charges can become a significant financial burden for the utility. To address this, utilities have often sought to include *construction work in progress* (CWIP) in rate base during the construction period. This allows them to earn a current return, covering the interest and dividends on the capital, even before construction is completed. CWIP, then, allows return on the cost of capital during construction, while AFUDC defers this accumulated cost of invested capital until after the plant is in service.

The inclusion of CWIP in rate base has been extremely controversial since the 1970s, when spiraling nuclear and coal construction costs created difficult circumstances for utilities, that were stretched thin trying to finance additions to the generating capacity. Where CWIP was allowed into the rate base, customers paid for interest and shareholder return during the construction process; in many cases, the power plants were never finished and never provided service, leaving consumers with a share of the dry-hole risk. A few states have allowed CWIP for new nuclear construction programs.

The rate base also includes some adjustments for working capital and deferred taxes. It may also include adjustments for certain deferred costs (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 9-3. The variables entering into the formula are described in more detail below.

Figure 9-3:

The Rate Base

	Total Plant In Service At Original Cost
-	Accumulated Provision for Depreciation
=	***Net Plant in Service***
+	Working Capital Allowances
-	Accumulated Deferred Taxes
+/-	Other Adjustments Approved by the Commission
=	***Rate Base***

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, since consumers will normally not pay their utility bills until some time after they receive service.[39] While it is not invested in hard assets that provide service, the utility is employing this capital for the benefit of the consumers, and it is therefore allowed to earn a return on it.[40]

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

39 Some utilities have moved to pre-payment 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 pre-payment.

40 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.

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, while others increase it.

9.2.3. Rate of Return

Utilities are allowed 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 U.S. Supreme Court decisions, known as Hope[41] and Bluefield[42], set out the general criteria that commissions must consider when setting rates of return.

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.

9.2.3.1. 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. 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, U.S. utilities have between 40%-60% debt, and between 40%-60% equity. There is no "right" level of equity: in Canada, equity ratios are more typically around 30%-35%, 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.

41 *Federal Power Commission vs. Hope Natural Gas Company,* 320 U.S. 591 (1944) ("Hope").

42 *Bluefield Water Works and Improvement Company vs. Public Service Commission,* 262 U.S. 679 (1923) ("Bluefield").

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.

9.2.3.2. 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 9-3, and Figure 9-4 provides an example of a rate of return calculation.

Figure 9-3:

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 9-4:

Hypothetical Rate of Return Calculation

		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%

9.2.3.3. 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.[43] While the cost of debt and preferred stock are usually set in advance, and precise data on what the utility will actually pay for those sources is known, the return to common stockholders must be determined in light of market conditions at the time of the rate case. 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 10% (after the utility's federal income taxes are covered), but it has been as low as 6% and as high as 16% 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.

Several methods are used to estimate the cost of equity, each based on economic theory and decades of research. 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.

9.2.3.4. Cost of Debt

Utilities finance part of their investment with debt, because debt is 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.

43 While 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.

While 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 where a utility issues variable-rate debt. However, particularly in states that use future test years, 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.

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

9.2.4. 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, while 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 multi-year 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, while others operate under formulas designed to give the utility an incentive to control costs. (Adjustment clauses are discussed in Section 11.)

9.2.4.1. 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. 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.

9.2.4.2. 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 onto customers' bills in these specific communities, rather than being included in the statewide revenue requirement.

9.2.4.3. Depreciation

While the rate of return is a return *on* capital (a payment for the use of facilities that work), 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. While 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.

9.2.5. 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.

9.3. Allocation of Costs to Customer Classes

In a general rate case, 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 seldom-used but very large connections). 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.

9.3.1. Embedded vs. Marginal Cost of Service Studies

Cost of service studies use complex arithmetic models, and their methods are highly controversial. This subsection 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, or actual, costs that the utility incurs — and divide those costs among the customer classes in the various ways outlined in the previous section. 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 kilowatt-hour 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 kilowatt-hour, because they require fewer distribution facilities and have more uniform usage patterns. However, if the costs of new facilities are dramatically different than those of existing facilities, 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 long-run costs. In the long-run, all costs are variable — the utility will have to replace power plants and transmission 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.

9.3.2. 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 generally estimated, because detailed peak load metering is typically only installed for larger-volume customers.[44]

44 Modern smart-grid meters do allow collection of interval data for low-volume users, and the accuracy of data for cost allocation will likely improve significantly as these data are collected and analyzed. For this and other reasons, it is important that advanced metering equipment be considered usage-related plant in cost allocation studies and rate design.

For a typical U.S. electric utility, residences make up about 90% of the customers, cause about 50% of the peak demand, and use about 40% of the energy sold.[45] 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 kilowatt-hour (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, while industrial representatives often advocate for a heavier weighting to *customer* and *demand usage* factors.

For the purpose of allocating demand-related costs, some studies define *peak* as only a few hours of the year, while others consider the highest peak demand in each of several months of the year or the highest 200 or more hours of the 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.

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 properly 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.[46]

9.3.3. "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

45 Customer and energy sales data is reported annually by the U.S. Energy Information Administration. The contribution to peak load is a rough average, based on a sampling of specific utility rate filings. All these usage factors can vary widely from utility to utility.

to treat a specific power plant as serving a specific industrial customer whose demand "caused" its construction.[47]

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.

9.3.4. 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 it 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. One often hears arguments based on the need for *gradualism* to be the guiding principle when rates are rising, with the rationale that large rate changes should be avoided

46 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, i.e., 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. While combustion turbines cost little to build, they are very expensive to run, such that the average total cost (capacity and operating) per kilowatt-hour 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.

47 For example, for many years the state of Vermont reserved low-cost hydropower to provide the first 200 kWh/month 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. 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 Tennessee Valley Authority. See: *Residential Baseline Inverted Rates,* Washington State Senate, 1981, available at http://www.raponline.org/docs/WashingtonState_BaselineRate1981Study.pdf.

where possible to provide some continuity of cost to all 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.

9.4. Rate Design Within Customer Classes

Typically, 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 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.

9.4.1. Residential Rate Design

Residential rates typically consist of a monthly customer charge (or basic charge), plus an energy charge in cents per kilowatt-hour based on the amount of usage. This energy charge may be a flat rate (the same for all usage), inverted (with higher rates for usage over a base level) or declining (with lower rates for usage over a base level).

As the following example shows, these three basic rate forms affect consumers with different usage levels quite differently, even though a consumer using 1,000 kWh/month pays the same bill under each rate design.

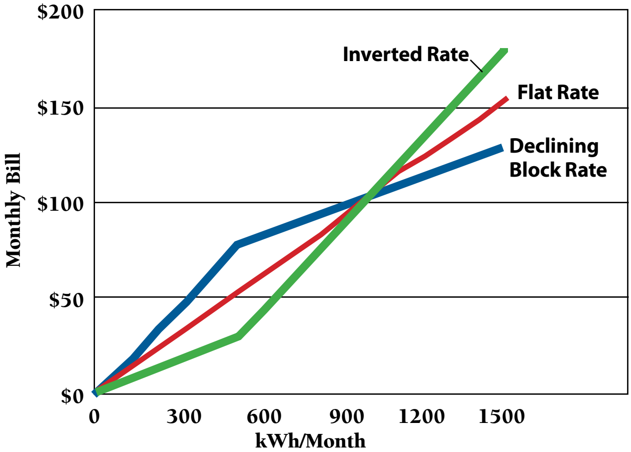
Figure 9-5:

Illustrative Residential Electric Rate Design

	Flat Rate	Inverted 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 9-6:

Illustrative Residential Bills With Different Rate Designs



Low-income advocates frequently focus on rate design issues in rate cases. Most low-income consumers have below-average usage, and an inverted rate design will favor them. Some low-income consumers, however, particularly those with large extended families or living in older inefficient housing, may have higher-than-average usage.

In most states, the customer charge is set to recover customer-specific costs, such as metering, meter reading, and payment processing. In other states, 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.[48]

Time-of-use (TOU) pricing is becoming more common for residential consumers, particularly those with 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.

48 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.

Figure 9-7:

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

In general, residential time-of-use rates are voluntary, while larger commercial and industrial customers may face mandatory TOU rates. The proper design of a time-of-use 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 with 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 utilization of TOU rates, including mandatory TOU rates for residential customers.

9.4.2. General Service Consumers

General service customers are businesses of any kind, including office, retail, and manufacturing enterprises. 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 businesses, 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 often have a *ratchet* feature, which adjusts the customer's monthly demand charge on the basis of its maximum demand during a preceding period, usually 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 kilowatt-hour is lower. In the example below, the average total revenue contribution for commercial usage will be about $0.10/kWh, roughly the same as in the residential example above. However, as a general matter, the rate structure does give the customer an incentive to moderate its peak demands, thereby reducing its capacity charges and lowering its average total cost per kilowatt-hour.

Figure 9-8:

Illustrative General Service Flat and Time-Of-Use 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

9.5. 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 delivery.

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.

9.6. Advanced Metering and Pricing

Utilities are introducing *advanced metering,* which allows them to measure usage in very short intervals by time of day, and to communicate information to and from the customer. 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. *Smart meters* can also receive signals from the utility—which may, for example, reset a thermostat to reduce load based on preset customer preferences. These smart meters have become quite inexpensive, and will likely be the norm in the future even for residential consumers.[49]

Some advanced rates are simple, with time-of-use blocks as discussed above, while 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 several times 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 time-of-use 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.

49 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.

Figure 9-9:

Illustrative Critical Period Pricing Rate Design

	Flat Rate	Mild Critical Peak Price	Steep Critical Peak Price
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	$0.50

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.

Many dynamic pricing rates are strictly voluntary: customers can choose to participate, or to stay with a more traditional rate design. It's probable that over time, both larger residential consumers and business consumers will increasingly be served through mandatory TOU and/or dynamic pricing rates.

9.7. Service Policies and Standards

All the utility's rates, policies, and standards are subject to change by the regulator during a rate case. 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, 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.

9.8. Issue-Specific Filings

Utilities make issue-specific filings between rate cases. These do not fall into any particular category. 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.

Utilities normally take the position that these are important reasons to adopt new tariffs, or to impose minor changes in rates, but do not justify re-opening the entire range of issues considered in a general rate case. Consumer advocates sometimes criticize this as *single-issue ratemaking,* in which the utility seeks to raise rates for those elements of cost that are increasing, without considering offsetting factors that may be decreasing costs. Some commissions' rules define the threshold at which a tariff filing becomes a general rate case, in which all issues may be considered.

9.9. 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 sections 10 and 15). 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.

9.10. Summary: The Fundamentals of Regulation

This abbreviated overview introduces the multitude of issues a regulatory commission deals with in setting utility rates and policies. The additional resources below provide more guidance on some of the specific topics discussed, but no single resource is a complete guide to the long and unique regulatory history of each state.

For more details:

Bonbright, 1961, *Principles of Public Utility Rates.*

"Estimating The Cost Of Equity: Current Practices And Future Trends In The Electric Utility Industry," *Engineering Economist Magazine*, 1999.

www.entrepreneur.com/tradejournals/article/59705097.html

Garfield and Lovejoy, 1964, *Public Utility Economics.*

Missouri Office of Public Counsel, *Rate Case Tutorial.*

www.mo-opc.org/upload/small_rate_case_tutorial.doc

Palast, Oppenheim, and MacGregor, 2003, *Democracy and Regulation.*

Phillips, 1985, The Regulation of Public Utilities.

Regulatory Assistance Project, 2000, *Charging for Distribution Services.* www.raponline.org/docs/RAP_Weston_ChargingForDistributionUtilityServices_2000_12.pdf

Regulatory Assistance Project, forthcoming, *Pricing Do's and Don'ts.* www.raponline.org/docs/RAP_PricingDosAndDonts_2011_04.pdf

10. Drawbacks of Traditional Regulation and Some Fixes

The system of traditional regulation described in the previous section 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 section identifies some of the more important ones, and responses to them. Section 14 discusses some newer and more innovative approaches to one of these problems, the *throughput incentive.*

10.1. Problems

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.

10.1.1. Cost-Plus Regulation

One of the most common critiques of traditional regulation, based on what is called the *Averch-Johnson Effect,* suggests that utilities will overbuild because their allowed return is a function of their investment.[50] Utilities have been accused of spending more on power plants, transmission, and distribution facilities than would be expected by a cost-minimizing, 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-

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

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. While commissions do review and sample operating expenses to determine if they are reasonable before approving them, it's questionable whether they have the ability 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. As discussed in Section 9, 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.

10.1.2. 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 kilowatt-hour 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. 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.

10.1.3. 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. As a result, utilities have requested — and some commissions have granted — mechanisms to deal with changes between rate cases, such as fuel adjustment clauses (these are discussed in some detail in Section 12). 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. While 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.

10.2. Responses

Many regulatory concepts have evolved to address these problems. Several are outlined here.

10.2.1. Decoupling, or "Revenue-Cap" 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. This is known as *revenue-cap* or simply *revenue* regulation. (Decoupling is discussed in greater detail in Section 15.)

10.2.2. 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.

Figure 10-1:

Comparison of Traditional Regulation and Price-Cap PBR

Traditional Regulation	Performance-Based Regulation
Rate Base	**Rates in Period 1**
X Rate of Return	+ Inflation
+ Operating Expenses	- Productivity
= Revenue Requirement	+ / - Z-factor
/ Sales = Rates	= Rates in Period 2

Commissions have learned to establish strict service quality standards when approving multi-year PBR mechanisms, because experience showed that some utilities took actions to improve earnings at the expense of reliability and customer service quality. See Section 17, on Service Quality.

10.2.3. Incentives For Energy Efficiency or other Preferred Actions

Some commissions have established incentive mechanisms to reward utilities that take specific actions or that achieve specific goals. These 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. Appropriate incentives or rewards for effective performance are increasingly recognized as sound regulatory practices, for which consumers are well-served.

10.2.4. Competitive Power Supply Contracting

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. Some commissions have required that renewable resources be acquired by contract, but still allow utilities to invest in conventional power plants.

10.2.5. Restructuring

Other states have gone further, as described in Section 4.4.1, 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.

10.2.6. 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 built in an economic fashion. Often consultants with 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 they are built. This is becoming increasingly important as older power plants face significant environmental retrofit costs. (See section 16 on environmental issues.)

10.2.7. Integrated Resource Planning

Integrated resource planning (IRP), which is discussed in more detail in Section 13, requires the utility to develop a publicly available, long-range plan for the best way to meet consumer needs over time, usually anywhere from 10-20 years. Typically the commission will review the plan, order modifications if necessary, and approve it as the guidance document for future utility investment and operations decisions. In most states, the plan itself is not "approved" per se, but is found to be a reasonable guide to future actions.

11. 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.[51] The transmission system allows utilities to use diverse resources — such as wind, coal, 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 cheaper than 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 U.S. Constitution reserves to Congress the power to regulate interstate commerce. Because power moves between states over transmission lines, 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, or the Los Angeles Department of Water and Power are not under FERC jurisdiction. Federal power marketing authorities, such as the Bonneville Power Administration, the Western Area Power Administration, and the Tennessee Valley Authority are also self-governing, and fall outside FERC's general regulatory authority. 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 section briefly describes the function of the transmission system, and how transmission pricing is regulated.

51 A small 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.

11.1. Transmission System Basics

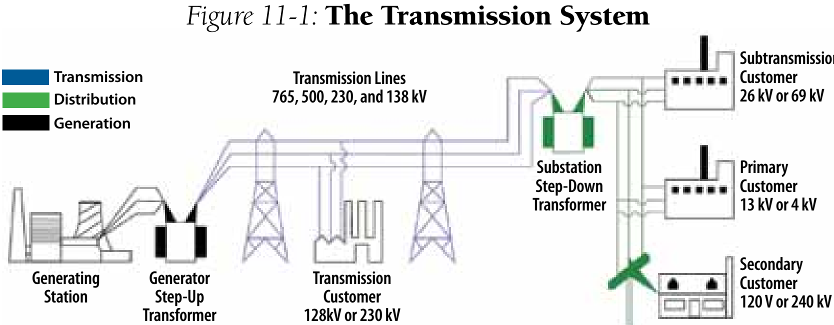
The transmission network moves power at high voltages over long distances. Generally, the term *transmission* applies to lines that carry power at voltages of 115 kV (115,000 volts) and above through big wires, mostly on steel towers. *Sub-transmission* consists of lines operating at 34.5 to 115 kV. These sub-transmission lines may be classified as transmission, subject to federal regulation, or as distribution lines subject to state regulation; this depends 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.

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.

In a few areas, power is also converted from alternating current (AC) to direct current (DC) for transmission purposes, since DC is more efficient for moving power very long distances. DC interconnections can also be used to move power between the Eastern U.S., the Western U.S., 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 10 locations along the boundary between the three U.S. 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 this diagram:

Figure 11-1: **The Transmission System**



Source: US-Canada Power System Outage Task Force final report, April 2004.

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 the North American Electric Reliability Corporation and enforced by FERC holds transmission owners and operators accountable for being prepared for contingencies. This is critical to reliability: if one transmission element fails, the effect can cascade through a system without protection systems in place. On a few occasions, entire regions of the country have been plunged 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; to monitoring transmission reliability, and to funding needed transmission system upgrades.

11.2. Transmission Ownership and Siting

Most transmission facilities in the U.S. 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.

With the U.S. system of franchised utilities, 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.

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.

In some states, authority for approving new transmission lines has been vested in a single agency to expedite the evaluation process and 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 U.S. Department of Energy assessment. In some parts of the U.S., the lack of new transmission lines has hampered the development of renewable energy resources, because current transmission lines do not necessarily lie in areas that are most advantageous to renewable energy. 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.

11.3. Transmission Regulation

FERC regulates the pricing of wholesale transmission transactions, both what is charged to utilities and what's 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 often *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 is to develop systems of joint pricing for transmission services.

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. However, there is currently no consumer advocate for the FERC process, 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, three key decisions by FERC guide current transmission regulation:

Order 888 (1996) detailed how transmission owners may charge for 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 non-discriminatory 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 regional transmission organizations. 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.

For more details:

Matthew H. Brown, National Conference of State Legislatures; Richard P. Sedano, The Regulatory Assistance Project, 2004, *Electricity Transmission: A Primer*. www.raponline.org/docs/rap_brown_transmissionprimer_2004_04_20.pdf

U.S. Department of Energy, 2002, *A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets.* www1.eere.energy.gov/femp/pdfs/primer.pdf

12. Tariff Adjustment Clauses, Riders, and Deferrals

This section 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 litigated. 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 — e.g., 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.[52] Periodic audits check to see if the mechanisms are being properly implemented.

The most common and most important of these mechanisms are *purchased gas adjustment* (PGA) mechanisms and *fuel adjustment clauses* (FACs). However, there are many different types of adjustment mechanisms and tariff riders in place.

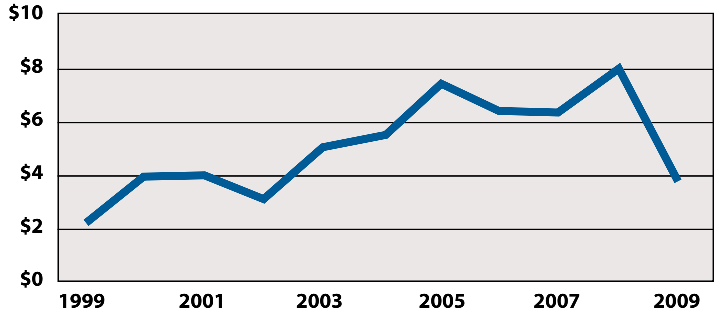
12.1. Gas Utility-Purchased Gas Adjustment Mechanisms

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 12-1 shows, the price of gas can change greatly on short notice, and the gas utility has little ability to influence the price of gas (except by signing multi-year contracts with fixed or indexed prices).

52 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 12-1:

Wholesale Natural Gas Prices 1999-2009



The cost of purchased gas typically makes up about two-thirds of a gas utility's total costs, and a sudden surge in wholesale gas prices can severely affect earnings and the ability to pay dividends.

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.

12.2. Electric Utility Fuel Adjustment Mechanisms

Electric utilities in the U.S. generate most of their power with coal and natural gas, and both of these are subject to significant price volatility. Utilities also buy power from other utilities and from non-utility generators, and those prices are also subject to change in response to market forces. During the oil embargoes of 1973-74 and 1978-79, when fuel costs shot up suddenly, most electric utilities sought and received approval for their first fuel adjustment clauses.

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, while 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, 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.

12.3. 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 Section 13, Energy Efficiency, 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. 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 an FAC or other cost recovery mechanism.

12.4. 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, while 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 where 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 due to productivity, technological innovation, and other causes.

12.5. 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, where 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. Compared with the flat rate shown in Figure 9-5, if weather caused lower utility sales, the utility would be allowed to recover an additional $.05 in revenue for each kWh of sales reduction due to weather, and vice-versa if sales were higher than assumed in the rate case: a small surcharge (surcredit) would recover (refund) the difference. Weather-only normalization is a form of limited decoupling, which is described in Section 15.

12.6. 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.

While all the tracking mechanisms described above generally do 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.

13. Integrated Resource Planning/ Least-Cost Planning

Integrated resource 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.

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 approve them, while others accept them without ruling; and some utilities prepare them without any regulatory requirement to do so.

This section discusses a formalized system of planning for future power supply, transmission, and distribution needs, including a provision for public involvement and commission oversight.

13.1. What is an IRP?

IRPs examine forecasted load growth for a utility, and evaluate alternative means of meeting that growth.[53] 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, 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.

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 utilities 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 least-cost resource mix for the utility and its consumers. *Least-cost* in this case means lowest total cost over the planning horizon, given the risks faced. The best resource mix is typically the

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

one that remains cost-effective across a wide range of futures and sensitivity cases — the most *robust* alternative — and that also minimizes the adverse environmental consequences associated with its execution. 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 non-traditional alternatives.

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

An IRP compares multiple alternatives, and examines the costs, reliability, and environmental impacts of each. The utility will use the results of the IRP to decide what types of resources to acquire, whether it's 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 pre-approval, 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 pre-approval 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.

13.3. 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.

Environmental regulators participating as stakeholders can also inform the IRP process. Any new power plant that receives a certificate of 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 determine, first, whether their existing standards are adequately protective; second, the level, timing, and stringency of future air, land, and water standards; and third, the potential role of energy efficiency 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.

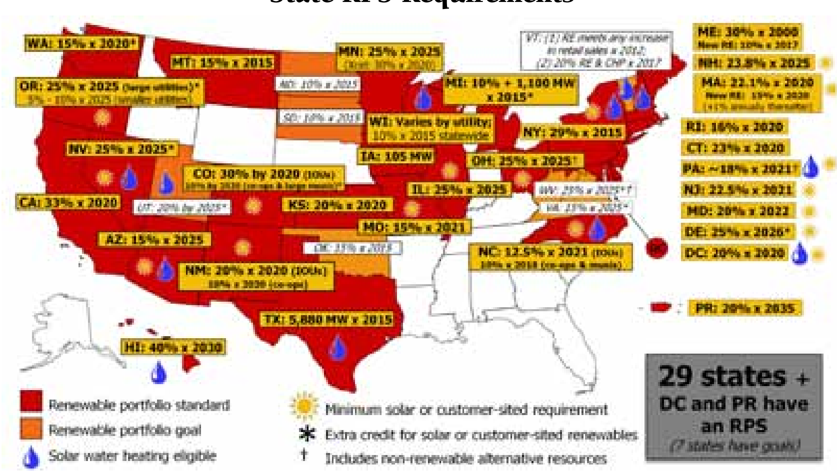
13.4. Energy Portfolio Standards and Renewable Portfolio Standards

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* (RPS). Several have required a specified mix of energy efficiency resources and renewable energy resources; these are known as *energy portfolio standards*. A few, including California, Washington, and Minnesota, have adopted requirements for utilities to secure all cost-effective energy-efficiency resources.

The map below shows states with RPS requirements as of November 2010.

Figure 13-1:

State RPS Requirements



Source: Database of State Incentives for Renewables and Efficiency. www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1

13.5. 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 Bonneville Power Administration. The Council planning process is set out in federal law.[54]

The First Power Plan, published in 1983, led to the termination of two partially completed nuclear power plants in which over $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. Billions of dollars were saved by the substitution, over the next 27 years, of energy efficiency investments for supply-side investments. This represents a tangible difference for consumers.

The Sixth Power Plan, released in 2010, contains more than 5,000 pages of analysis, and recommends that the Pacific Northwest take the following actions:

- Invest in 5,900 megawatts of energy efficiency, virtually all of which is cost-effective even without any carbon dioxide mitigation requirement;
- Improve energy building codes for residential, commercial, industrial, and agricultural facilities;
- Invest in approximately 5,000 megawatts of wind and geothermal resources;
- Plan for the possibility of some additional natural gas generation, particularly for peaking;
- Potentially retire existing coal plants and replace them with new generating facilities, which will become cost-effective if the price of carbon exceeds $40/ton.

The Council process is public, transparent, and very technically sophisticated. While 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 details:

National Association of Regulatory Utility Commissioners, 1989, *Profits and Progress Through Least-Cost Planning.* www.raponline.org/Pubs/General/Pandplcp.pdf

www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf

Northwest Power and Conservation Council, 2010, *Sixth Power Plan.* www.nwcouncil.org/energy/powerplan/6/default.htm

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

14. Energy Efficiency Programs

Energy efficiency is considered *cost-effective* when the cost of installing and maintaining measures that improve the efficiency of energy usage, compared with what the consumer would otherwise do, 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.

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. Last, but not least, the society avoids the pollution and other externalities caused by power production.

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

14.1. Why Are Utility Commissions Involved?

It is not usually natural for a business to try to reduce the demand for its services — yet utilities may be uniquely qualified to play a role in improving the efficiency of energy usage. They have relevant technical knowledge, and they have a business relationship with all of the energy users in their service territory. 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 costly new supplies and efficiency — and this 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 (rather than unique objects, like the Mona Lisa), that all producers and consumers have perfect information, that no producer or consumer is large enough to move the market, that there is free entry and exit, and that capital is fungible and can be instantly redeployed. None of these precepts holds true in the 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.

While many of these market failures can be addressed through better consumer information, by more accurate, forward-looking pricing of energy, or through strict codes and standards, evidence shows that those options 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 cannot 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 carbon dioxide 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.

14.2. 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, but they are separate economic entities, and generally are subject to oversight and regulation by the utility regulatory commission.

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.

14.3. 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, to be 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, and market failures owing to lack of awareness and training among vendors, builders, etc.

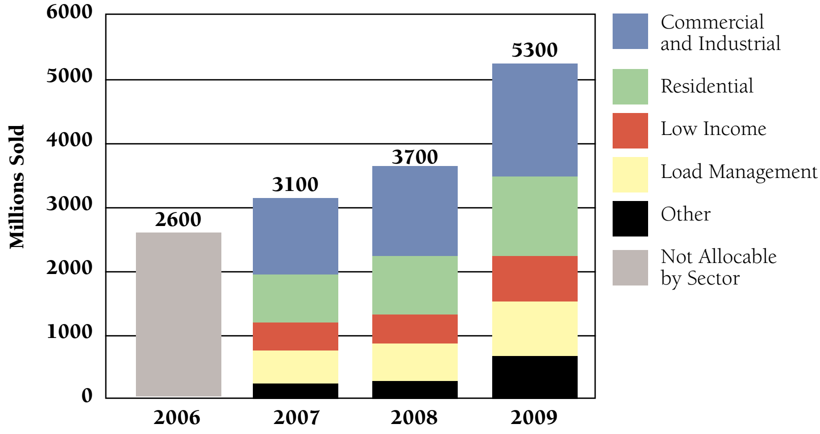
In several states, the utility (or third-party provider) is charged with procuring all cost-effective energy efficiency. These organizations must operate a complete range of programs directed at all end-uses of energy and all classes of consumers. They promote efficiency in both new construction and 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, 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 commercially viable. And, perhaps most important, they engage in detailed program evaluation to ensure that their expenditures provide a net benefit to consumers.

In 2009, electric and gas utilities invested over $5 billion in energy efficiency programs.

Figure 14-1:
U.S. Utility Investment in Energy Efficiency Programs 2006-09

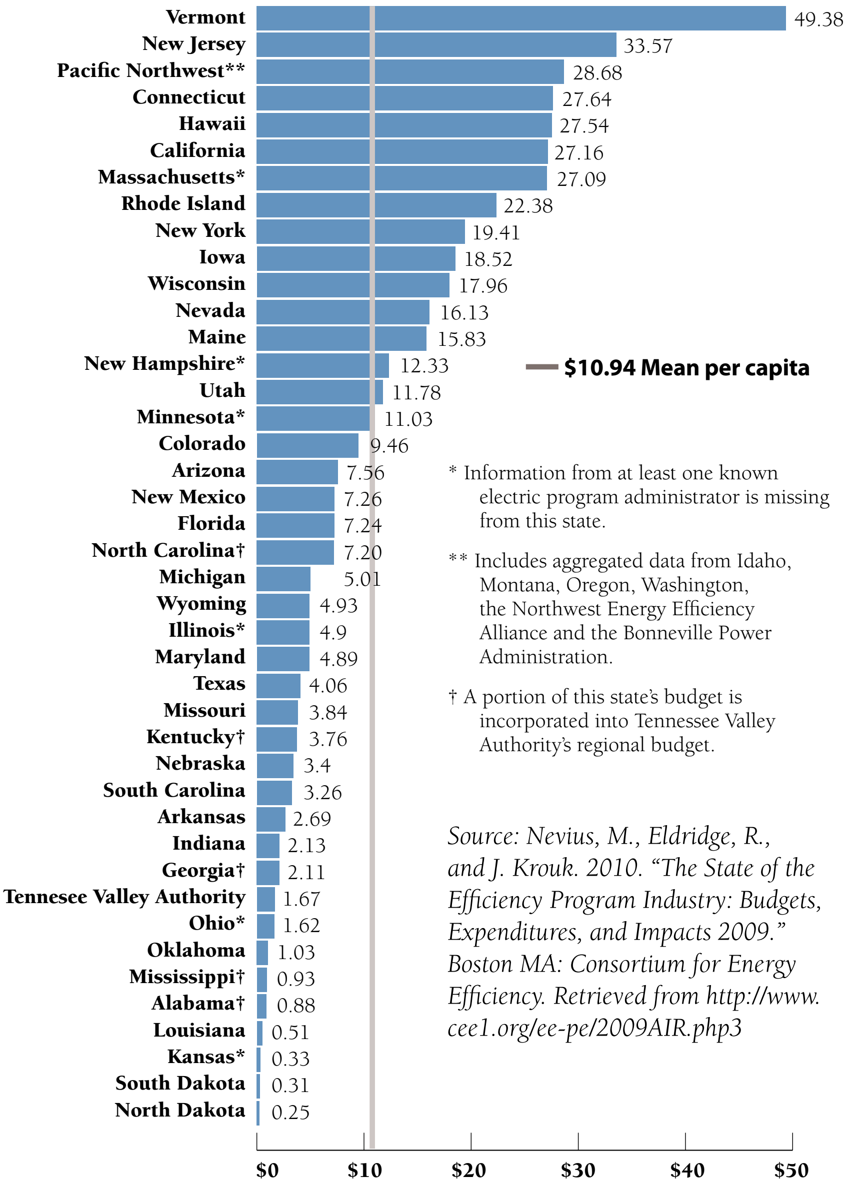


Source: Nevius, M., Eldridge, R., and J. Krouk. 2010. "The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts 2009." Boston MA: Consortium for Energy Efficiency. Retrieved from http://www.cee1.org/ee-pe/2009AIR.php3

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, but recent movement in Minnesota and Wisconsin and a few other upper Midwestern states indicates that the trend is expanding.

Figure 14-2:

Annual Per-Capita Utility Investment in Energy Efficiency Programs by State



* Information from at least one known electric program administrator is missing from this state.

** Includes aggregated data from Idaho, Montana, Oregon, Washington, the Northwest Energy Efficiency Alliance and the Bonneville Power Administration.

† A portion of this state's budget is incorporated into Tennessee Valley Authority's regional budget.

Source: Nevius, M., Eldridge, R., and J. Krouk. 2010. "The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts 2009." Boston MA: Consortium for Energy Efficiency. Retrieved from http://www.cee1.org/ee-pe/2009AIR.php3

14.4. 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 amounts paid by large industrial customers are sequestered, and available only for the use of the customer that 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. In some states, both the revenue and expenditures for certain classes of customer are handled separately.

14.5. Total Resource Cost, Utility Cost, and Rate Impact Tests

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

The most important of these is the *total resource cost* (TRC) test, which compares all the costs of energy efficiency measures to all the costs of the energy supply alternative. In the TRC, it is critical to count *all* non-energy benefits of efficiency measures, considering their implications for water, sewer, natural gas, 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.[55] A variation of the TRC, called the *societal cost test*, includes non-monetary costs and benefits such as environmental damage and health impact costs, on the one hand, and improved customer amenity value derived from efficiency measures on the other.

The *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% incentive for a lighting retrofit, only half the cost of the efficiency measure would be counted, and

55 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.

compared with 100% 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 *ratepayer impact measure* (RIM) test measures whether a given efficiency program causes rates to rise or fall for non-participants in the program. Most energy efficiency measures that save a significant amount of energy fail the RIM test. 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.

14.6. 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.

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 2010, 24 states have adopted EERS of some form, and four have pending standards.[56]

For more detail:

Regulatory Assistance Project, 2007, *Energy Efficiency Policy Toolkit.* www.raponline.org/Pubs/Efficiency_Policy_Toolkit_1_04_07.pdf

Renewable Energy and Energy Efficiency Partnership, 2010, *Compendium of Best Practices: Sharing Local and State Successes in Energy Efficiency.* www.raponline.org/docs/RAP_REEEP_CompendiumofBestPractices_2010_05_28.pdf

Regulatory Assistance Project, 2010, *Smart Policies Before Smart Grids: How State Regulators Can Steer Smart Grid Investments Toward Customer-Side Solutions.* www.raponline.org/docs/RAP_Schwartz_SmartGridACEEEsummerstudy_2010_8_17.pdf

American Council for an Energy Efficient Economy, 2010, *State Energy Efficiency Policy Database.* www.aceee.org/sector/state-policy/utility-policies

Consortium for Energy Efficiency, *Energy Efficiency Program Budget and Expenditure Data.* www.cee1.org/ee-pe/2009AIR.php3#budgetdata

56 A survey of EERS in place is available from the American Council for an Energy Efficient Economy at www.aceee.org/node/5981

15. Aligning Regulatory Incentives with Least-Cost Principles

In Section 9, 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 section 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.

15.1. Effect of Sales on Profits

While 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 Section 10, 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.[57] 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.

57 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's 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.

15.2. 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.)

15.2.1. Decoupling

Decoupling can reduce throughput incentives, since (as noted earlier) it ensures that the utility's revenues, in certain defined categories, are not affected by sales volumes.[58] 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 *fuel adjustment clause* (FAC). 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 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. Most mechanisms operate on a *deferral* basis, with any amounts not recovered or over-recovered due 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, while others set an amount to be recovered per customer, so that changes in the number of customers results in changes in 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.

58 This is an abbreviated discussion of the topic; two detailed RAP papers on decoupling are available on the RAP website. See www.raponline.org.

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 due to weather may be excluded, with sales volumes recalculated based on the normal weather conditions used in the rate case.
- **Partial Decoupling:** Only a portion of the revenue lost or gained due to sales volume variations is included in the calculation of the decoupling adjustment. For example, the commission may allow only 90% of the lost or gained revenue to be included.

Decoupling is relatively simple to administer. Each billing cycle, month, or year, the amount of revenue allowed in the rate case 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 due 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 *formula 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, formula rates can also encompass other types of incentive and adjustment mechanisms.

15.2.2. 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 9-5, for example, the utility has about $.05/kWh included in the rate for costs that do not change as usage changes. The utility would get to recover an additional $.05 for each kWh of sales displaced by utility efficiency programs. However, the utility would not get any recovery of lost margin if consumers invested in efficiency themselves, or if sales declined due to economic conditions, weather, or other factors. Because fewer costs are included, the rate changes are generally smaller than under full decoupling.

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. Further, added sales still redound to the benefit of the utility, so the throughput incentive to build load remains.

15.2.3. 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. While 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.

15.2.4 Future Test Years.

Some commissions use *future test years* to set rates. As Section 8 describes, these set the expected sales based on forecasts of costs and sales. If the utility has forecast that sales will decline due to 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 multi-year throughput incentive.

15.2.5. Straight Fixed-Variable Pricing (SFV).

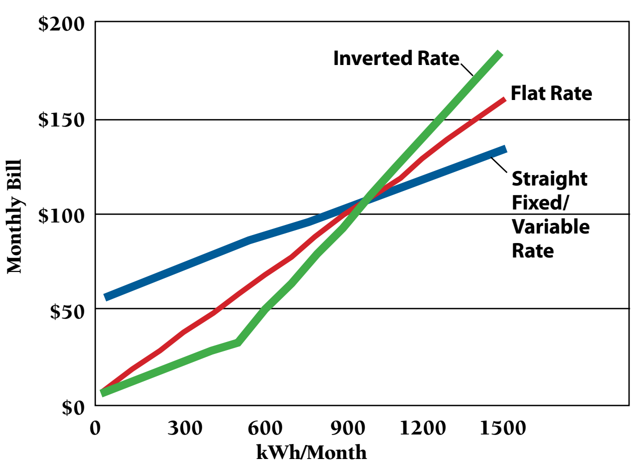
Some utilities and regulators have implemented pricing schemes that collect not only customer-specific costs, but all of the distribution costs that do not vary with sales in the short run as a fixed charge each month. They then include only the variable costs of fuel and purchased power in the rate per unit. This is called *straight fixed/variable pricing*, or SFV. This compares to the rate design discussed in section 9.4, in which the customer charge is based solely on the cost of meters, meter reading, and billing.

Figure 15-1 shows an example of SFV, assuming fuel (and other variable) costs of about $.05/kWh. While SFV pricing protects utility profits from erosion when sales decline, and does not give the utility a 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, since the fixed portion of the charge is, in effect, spread across fewer units of sale than it is for higher-volume users. 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% in the example in Figure 15-1) for low-usage customers.

SFV rates favor the largest residential users, at the expense of smaller users. Large residential users are typically those with space conditioning loads — heating 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.

Figure 15-1:

Illustrative Straight-Fixed Variable Rate Design



	Flat Rate	Inverted Block Rate	Straight Fixed/Variable Rate
Customer Charge	$5.00	$5.00	$55.00
First 500 kWh	$0.10	$0.05	$0.05
Over 500 kWh	$0.10	$0.15	$0.05
Customer Bill			
0 kWh	$5.00	$5.00	$55.00
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

15.2.6. Incentive/Penalty Mechanisms

Some commissions have simply created profit incentives and/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.

For more details:

Regulatory Assistance Project, 2006, *Energy Efficiency Policy Toolkit.* www.raponline.org/Pubs/General/EfficiencyPolicyToolkit.pdf

Regulatory Assistance Project, 2008, *Revenue Decoupling — Standards and Criteria, A Report to the Minnesota Public Utilities Commission.* www.raponline.org/docs/RAP_RevenueRegulationandDecoupling_2011_04.pdf

Regulatory Assistance Project, Forthcoming, *Revenue Regulation & Decoupling: Theory and Application Guide.* See www.raponline.org.

16. Regulatory Treatment of Emission Costs

Coal-fired power plants produce almost half of America's electricity, and natural gas plants provide another quarter of it. Burning either of these fossil fuels emits pollutants currently regulated under the Clean Air Act, along with carbon dioxide and pollutants likely to be regulated in the future, such as mercury.

This section briefly discusses how regulatory commissions treat emissions costs.

In general, regulatory commissions have allowed utilities to recover the cost 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.

16.1. Currently Regulated Emissions

Sulfur Dioxide (SO2): A nationwide cap-and-trade program on SO2 emissions has been in place since 1990 to reduce acid rain and other adverse effects. The program initially granted free allowances to utilities, based on their pre-1990 emissions levels; but it has reduced these allowances each year, and now only about half as much sulfur is allowed to be released as when the program began. Under the proposed Transport Rule issued by the U.S. EPA in August, 2010, SO2 levels will have to be reduced substantially below current levels.

Nitrogen Oxides (NOX): Emissions of nitrogen oxides have been reduced by over 60% since regulations took effect in 1998 in California, the Northeast, and the Mid-Atlantic states. NOX regulations will likely be strengthened in the future.

Particulates: Power plants emit small particles of solid matter when they burn fuel. This is particularly significant for coal- and wood-fired plants, but burning oil also emits particulates. EPA's Clean Air Visibility Rule requires states to develop and implement plans for electric generating units that were placed into service between 1962 and 1977. Current regulations govern particles down to 2.5 microns in diameter. There is evidence that even smaller particulates, known as *nano-particulates,* have adverse health effects, and these may be regulated in the future.

Water: Power plants are subject to regulations, both on the amount of cooling water they can draw and on the pollutants they may discharge with it. These standards are likely to be strengthened in the future.

16.2. Anticipated Regulation

Carbon Dioxide (CO2): In New England, utilities are already subject to limitations on CO2, and are required to purchase allowances from a regional auction. A portion of the proceeds from those transactions pay for energy efficiency and renewable energy programs, and a portion goes to the states for general tax purposes. Regulators in New England review utility operations to see if they are acting prudently in acquiring power from plants that emit CO2, and acquiring allowances to meet their obligation. The costs they judge prudent flow through to consumers. Nationally, CO2 will likely be regulated either by the U.S. EPA under the Clean Air Act, or in a separate program if carbon regulation is approved by the Congress. The forms of future regulation is not known, nor are the associated costs that utilities will incur.

Mercury: Many states currently regulate mercury emissions. The U.S. EPA is currently implementing regulations for emissions of mercury on a national basis. These regulations will likely require retrofits of many coal-fired power plants.

Coal Ash: The ash that is precipitated from coal smokestacks contains an assortment of hazardous materials, dependent on the chemical composition of the coal. EPA is proposing new regulations for management and disposal of coal ash under the Resource Conservation and Recovery Act.

16.3. Commission Treatment of Emissions Management Costs

In the past, regulatory commissions have generally allowed the cost of emission regulation 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 actual varying costs through between general rate cases.

In the future, regulatory commissions will be faced with additional requests from utilities dealing with increased emissions costs. Because the regulations are not all being implemented simultaneously, it is crucial that regulators look at these costs prospectively — requiring utilities to consider not only those emission regulations that are imminent, but also those that are likely in the future.

In some cases, it may not be cost-effective to continue operating existing units once the additional regulations are in place, taking into account the remaining life of the units, the cost of retrofits, and the operating costs of pollution control equipment. Alternatives, including energy efficiency, renewable energy resources, or high-efficiency natural gas generation may be less expensive than continued operation of older power plants.

Commissions will have to determine whether or not to allow utilities to invest in and recover the costs of the retrofits and emission allowances needed to continue operating those plants, and perhaps whether to allow them to recover the costs of remaining investment in uneconomic power plants 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 that are not are phased out.

For more details:

Regulatory Assistance Project, Forthcoming, *Regulatory Treatment of Emission Costs.* www.raponline.org/docs/RAP_RegulatoryTreatmentofEmissionCosts_2011_05.pdf

17. Low-Income Assistance Programs

Utilities in many states provide various forms of assistance for low-income consumers, augmenting state and federal programs. 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.

17.1. 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 all are higher to fund this discount, and all consumers are considered to be better off because utility service to consumers with the lowest incomes is more secure.

A lifeline rate should not be confused with a *baseline inverted 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 inverted block rate is cost-based. 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 inverted 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 17-1:

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
Customer Bill			
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

17.2. 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 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. Neither do typical utility efficiency programs available to all consumers 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.

17.3. 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. 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.

17.4. Payment Programs

Most utilities have *budget billing* programs that provide a uniform bill each month. These are typically available to all consumers; but in many states, 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.

17.5. 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, at the utility's short-term borrowing cost; a few also pay interest on any overpayment or credit balance at the same rate they charge consumers with delinquencies.

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.

17.6. 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 multi-year 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, generally bear the cost of unpaid bills.

17.7. Disconnection/Reconnection

When low-income consumers do not pay their bills, utilities eventually disconnect their service, following 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 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 weather-related 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 connection with Section 19, will allow utilities to avoid these costs by remotely disconnecting and reconnecting service — but some low-income advocates have expressed concern about disconnection without notice or personal contact. Perhaps local social services staff can substitute for the utility visit at lower cost. Engineers concerned with safety have also expressed reservations about remote reconnection: appliances left on during a disconnection can create fire hazards if reconnected when no one is present.

For more details:

Fisher, Sheehan and Colton, *Home Energy Affordability Gap.* http://www.homeenergyaffordabilitygap.com/08_AboutFSC2.html

Palast, Oppenheim, and MacGregor, 2003, *Democracy and Regulation.*

People's Organization for Washington Energy Resources, 1982, *The People's Power Guide*, www.raponline.org/docs/WER_PeoplePowerGuide_1982.pdf

See the website of the National Consumer Law Center: www.nclc.org

18. 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 multi-year rate plans, where the likely result is that the utility will not be in front of the commission for an extended period, such as the PBR mechanisms discussed in Section 10.

Some of these are formal *service quality index* (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 multi-year rate agreement, in order to assure that utility earnings do not come at the expense of customer service quality.

Figure 18-1:

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 percent	93 percent	☑
Percent of customers satisfied with field services, based on survey	At least 90 percent	95 percent	☑
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.34	☑
CUSTOMER SERVICES			
Percent of calls answered live within 30 seconds by our Customer Access Center	At least 75 percent	78 percent	☑
Number of disconnections per year, per customer for non-payment	No more than 0.030	0.029	☑
OPERATIONS SERVICES			
Frequency of non-major-storm power outages, per year, per customer	Less than 1.30 outages	1.09 outages	☑
Length of non-major-storm power outages per year, per customer	Less than 2 hours, 16 minutes	3 hours, 10 minutes	☐
Time from customer call to arrival of field technicians in response to electric system emergencies	No more than 55 minutes	51 minutes	☑
Time from customer call to arrival of field technicians in response to natural gas emergencies	No more than 55 minutes	33 minutes	☑
Percent of service appointments kept	At least 92 percent	99 percent	☑

KEY MEASUREMENT	BENCHMARK	2009 PERFORMANCE	ACHIEVED
CUSTOMER SATISFACTION			
Percent of customers satisfied with our Customer Access Center services, based on survey	At least 90 percent	93 percent	☑
Percent of customers satisfied with field services, based on survey	At least 90 percent	95 percent	☑
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.34	☑
CUSTOMER SERVICES			
Percent of calls answered live within 30 seconds by our Customer Access Center	At least 75 percent	78 percent	☑
Number of disconnections per year, per customer for non-payment	No more than 0.030	0.029	☑
OPERATIONS SERVICES			
Frequency of non-major-storm power outages, per year, per customer	Less than 1.30 outages	1.09 outages	☑
Length of non-major-storm power outages per year, per customer	Less than 2 hours, 16 minutes	3 hours, 10 minutes	☐
Time from customer call to arrival of field technicians in response to electric system emergencies	No more than 55 minutes	51 minutes	☑
Time from customer call to arrival of field technicians in response to natural gas emergencies	No more than 55 minutes	33 minutes	☑
Percent of service appointments kept	At least 92 percent	99 percent	☑

For more details:

Alexander, "How to Construct a Service Quality Index in Performance-Based Ratemaking," *Electricity Journal*, April 1996.

Regulatory Assistance Project, 1996, *Consumer Protection Proposals For Retail Electric Competition: Model Legislation And Regulations.* www.raponline.org/docs/RAP_Alexander_ConsumerProtectionProposalsforElectricCompetition_1996_10.pdf

19. 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.

It is hoped that the Smart Grid will eventually:

(1) enable consumers to manage their energy usage and choose the most economically efficient way to meet their energy needs;

(2) allow system operators to use automation and a broad array of resources to help maintain delivery system reliability and stability; and

(3) help utilities to rely on the most economical and environmentally benign resources – generation, demand-side, and storage alternatives – to meet consumer demands.

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.

- **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, 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 other elements.

The hypothetical benefits of Smart Grids are immense, but the realization of these benefits is not assured without such supportive policies. Examples of the potential benefits include:

- Integrating renewable resources like wind by automatically turning water heaters 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;
- Quickly identifying the cause of service outages, even predicting them, and improving the speed of service restoration;
- 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; and

- Adding intelligence to transformers to protect against faults and overloads.

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 been the costs of replacing meters and utility system control equipment, ensuring that the additional costs of that equipment (e.g., installed to help reduce meter-reading costs and control energy costs) are properly addressed in rate design, and alternative policies options related to rate design implementation (e.g., optional or mandatory time-of-use pricing). Some regulators have supported Smart Grid investments, and others have found that the benefits do not justify the costs in the specific cases before them.

Many of the benefits of Smart Grids can be secured without new rate designs. Some categories of benefits – particularly those associated with load response – require prices that reflect incremental 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. 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 more details:

Smart Grid or Smart Policies: Which Comes First?, Regulatory Assistance Project, 2009, http://www.raponline.org/docs/RAP_IssuesletterSmartGridPolicy_2009_07.pdf

Is It Smart if It's Not Clean? Questions Regulators Can Ask About Smart Grid and Energy Efficiency. Pt 1: Strategies for Utility Distribution Systems, Regulatory Assistance Project, 2010. http://www.raponline.org/docs/RAP_Schwartz_SmartGridDistributionEfficiency_2010_05_06.pdf

Lisa Schwartz, *Smart Policies Before Smart Grids: How State Regulators Can Steer Investments Toward Customer-Side Solutions,* 2010 ACEEE Summer Study on Energy Efficiency in Buildings, http://raponline.org/docs/RAP_Schwartz_SmartGrid_ACEEE_paper_2010_08_23.pdf

The Smart Grid: An Annotated Bibliography of Essential Resources, NARUC, 2009, http://www.naruc.org/Publications/NARUC%20Smart%20Grid%20Bibliography%205_09.pdf

The Need for Essential Consumer Protections: Smart Metering Proposals and the Move to Time-Based Pricing, 2010, http://www.nasuca.org/archive/White%20Paper-Final.pdf

20. Summary: Regulation in the Public Interest

The role of the regulator is complex. Ensuring reliable service at reasonable cost 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. Limiting the environmental impacts of the utility system while also assuring reasonable prices, reliability, and safety is the daunting challenge that utility regulators face. Evolving technology provides new opportunities, but also creates new challenges.

In a general rate case, all 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 challenging if left unresolved until later in the proceeding.

The end result of progressive regulation should be a constructive working relationship among the various participants, and an efficient, thorough, open, and complete resolution of important issues.

Glossary

A

Accumulated Deferred Income Taxes (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.

Adjustment Clauses: Allow for recovery of specified costs as incurred, e.g., on a monthly or annual basis.

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center. *(See Smart Grid.)*

Allocation: The assignment of utility costs to customers, customer groups, or unbundled services based on cost causation principles.

Allowance for Funds Used During Construction (AFUDC): The capital costs that would have been accumulated on capital committed to a new utility plant during the construction period.

Alternating Current (AC): Current that reverses its flow periodically. Electric utilities generate and distribute AC electricity to residential and business consumers.

Ancillary Services: Services needed to support the transmission of energy from generation to loads, while maintaining reliable operation of the transmission system. These include regulation and frequency response, spinning reserve, non-spinning reserve, replacement reserve, and reactive supply and voltage control.

Annualization: An adjustment to a cost-of-service study to reflect the effect over 12 months of a rate base, income, or expense item that is only actually in effect for part of the year.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. *(See Marginal Cost Pricing, Value-Based Rates.)*

Avoided Cost: The cost of providing additional power, including 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.

B

Baseline Rate: A rate which allows all customers to buy a set allowance of energy at lower rates than additional usage. *(See Lifeline Rates.)*

Baseload Capacity: The generating capacity normally operated at all times to serve load. Typically, this includes units with low fuel and operating costs such as coal and nuclear generators.

Billing Cycle: The period of time between customer bills, typically one or two months.

BTU (British Thermal Unit): A standard unit for measuring the quantity of heat energy, equal to the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

C

Capacity: The maximum amount of power a generating unit or power line can provide safely.

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.

Capital Structure: The mix of common equity, preferred equity, and debt used by a utility to finance its assets.

Capitalized Costs: Utilities capitalize costs of investments that provide service over multiple years. (See Operation and Maintenance Costs.)

Carbon Intensity: The carbon dioxide a utility emits divided by its energy sales, typically expressed in tons/megawatt-hour.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Cogeneration: A method of producing power in conjunction with providing process heat to an industry, or space and/or water heat to buildings. Also called Combined Heat and Power (CHP).

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Combined Cycle: A generating plant that uses fuel to drive a turbine and the waste heat to operate a boiler, thereby achieving greater fuel efficiency.

Commodity Costs: Gas supply costs that vary with the quantity supplied.

Congestion: A condition that occurs when insufficient transfer capacity is available to implement all the preferred schedules for electricity transmission simultaneously. Congestion prevents the economic dispatch of electric energy from power sources.

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.

Construction Work in Progress (CWIP): Charges included in current rates to cover the cost of borrowing money for major energy projects still being built.

Cooperative Electric Utility (Co-op): A private non-profit electric utility legally established to be owned by and operated for the benefit of those using its service. About 10% of Americans are served by co-ops.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility *(see Value-Based Rates)*.

Cost of Debt: The interest rate paid by a utility on bonds and other debt.

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or **Critical Peak Pricing (CPP):** Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer 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. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

D

Declining Block Rate: A rate structure that prices successive blocks of power at increasingly lower per-unit rates. *(See Inverted Block Rate.)*

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Deferred Costs: An expenditure not recognized as a cost of operation of the period when it occurred, but carried forward so as to be recovered in future periods.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.

Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a billing period.

Demand-Side Management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of their demand.

Depreciation: The loss of value of assets such as buildings and transmission lines, due to age and wear.

Direct Access: The utility provides only distribution service to the consumer, while the consumer purchases the power from a different supplier.

Direct Current (DC): An electric current that flows in one direction, with a magnitude that does not vary or that varies only slightly.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

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.

E

Eastern Interconnection: One of three major AC power grids in North America, reaching from central Canada eastward to the Atlantic coast (excluding Quebec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas).

Economic Dispatch: The utilization of existing generating resources to serve load as inexpensively as possible.

Elasticity (of Demand): The percent change in usage with respect to a one percent change in price.

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. *(See Marginal Cost.)*

Energy Audit: A program in which an auditor inspects a home or business and suggests ways energy can be saved.

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed.

Energy Intensity: Economy-wide energy intensity measures units of energy relative to units of gross domestic product (GDP). EIA computes energy consumption (measured in Btu) relative to the constant dollar value of the GDP.

Energy Portfolio Standard: A regulatory requirement that a utility meet a specified percentage of its power requirements from a combination of qualified renewable resources or energy efficiency investments. *(See Renewable Portfolio Standard.)*

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).

Extraordinary Items: An accounting term meaning significant items of income or loss resulting from events or transactions in the current period that are unusual and infrequent. Extraordinary storm losses are an example.

F

FERC: The Federal Energy Regulatory Commission.

Firm Power: Electricity delivered on an always-available basis. *(See Interruptible Power.)*

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

Flat Rate: A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Franchise Tax: Taxes levied by states and localities as a condition of utility operation, usually in lieu of charging rental for public rights of way.

Fuel and Purchased Power Adjustment Clause (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. Sometimes called by other names, such as Energy Cost Adjustment Clause.

Functionalization: The separation of costs among utility operating functions, which traditionally include: production, transmission, distribution, customer accounting, customer service and information, sales, and administrative and general.

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Future Test Year: A regulatory accounting period that estimates the rate base and operating expenses a utility will incur to provide service in a future year, typically the first full year when rates determined in that rate case will be in effect.

G

Greenhouse Gases: Gases that trap heat in the atmosphere, including carbon dioxide emitted from power plants.

Green Power: An offering of environmentally preferred power by a utility to its consumers, typically at a premium above the regular rate.

H

Heat Rate: A measure of generating-station thermal efficiency commonly stated as Btu per kilowatt-hour.

Historical Test Year: A regulatory accounting period that measures the costs that a utility incurred to provide service in a recent year, typically adjusted for known and measurable changes since that year.

I

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Incremental Pricing: A method of charging customers based on the cost of augmenting the existing utility system, in which low-cost resources are sold at one price, and higher-cost resources at higher prices.

Independent System Operator (ISO): A non-utility that has 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.

Integrated Resource Planning (IRP): A public planning process and framework within which the costs and benefits of both demand and supply side resources are evaluated to develop the least total-cost mix of utility resource options. Also known as least-cost planning.

Interest Coverage Ratio: The annual net income divided by the annual interest charges on debt. It indicates the margin of safety for bondholders.

Intervenor: An individual, group, or institution that is officially involved in a rate case.

Interruptible Power: Power made available under agreements that permit curtailment or cessation of delivery by the supplier. Customers typically receive a discount for agreeing to have their power interrupted. Interruptions are usually limited to reliability needs, rather than the cost of power.

Inverted Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

J

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

K

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour. The W is capitalized in the acronym in recognition of electrical pioneer James Watt.

L

Levelized Cost, Life-Cycle Cost: The present value of the cost of a resource, including capital, financing, and operating costs, converted into a stream of equal annual payments per unit of output. EPRI formula: PV(cost)/PV(kWh), using the same discount rate for both.

Lifeline Rate: A lower rate for qualified low-income consumers. The discount may apply only to the basic charge, only to the initial block of usage, or to all usage.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

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 (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.

Local Distribution Company (LDC): A utility engaged primarily in the retail sale and/or delivery of natural gas through a distribution system.

Load Shedding: Disconnection of certain customers or circuits when system emergencies would otherwise cause a complete outage.

Load Shifting: Moving load from on-peak to off-peak periods.

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: The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system.

M

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. *(See Embedded Cost.)*

Market Clearing Price: The price at which supply and demand are in balance, with respect to a particular commodity at a particular time.

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Municipal Utility (Muni): A utility owned by a unit of government, and operated under the control of a publicly elected body. About 15% of Americans are served by munis.

N

Negawatt: A unit of saved power from energy efficiency programs equal to one megawatt at the generating level. Because of avoided losses and reserves, it takes only about 800 kilowatts of load reduction to avoid 1 megawatt of power supply. *(See Rosenfeld.)*

Net Income: Operating income plus other income and extraordinary income less operating expenses, taxes, interest charges, other deductions, and extraordinary deductions.

Non-Coincident Demand (NCD) or **Non-Coincident Peak Load:** A customer's maximum energy demand during a billing period or a year, even if it is different from the time of the system peak demand. *(See Coincident Peak.)*

Non-Operating Revenues: Sometimes referred to as other operating revenues, these are revenues that are incidental to a utility's revenues for primary service activities (e.g., investment income, land leases, pole rentals.)

North American Electric Reliability Corporation (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 sub-regional reliability organizations are subject to NERC's purview.

O

Open Transmission Access: Provides all participants in the wholesale market equal access to transmission service, as long as capacity is available, with the objective of creating a more competitive wholesale power market.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Operating Revenues: Revenues directly related to the utility's primary service activities.

P

Path Rating: The maximum amount of power than can be transmitted through a particular "path" on the electric system — usually applied to high voltage transmission. A particular path may be thermally limited, based on the physical properties of the transmission medium (i.e. how much heat the line can take before it begins to fail or degrade). Alternatively, a path may be stability limited, based on the effect of the power flow on operational constraints such as voltage and frequency.

Payback Period: The amount of time required for the net revenues of an investment to return its costs. This metric is often employed as a simple tool for evaluating energy efficiency measures.

Peak Load: The maximum total demand on a utility system during a period of time.

Peak Shaving: Employment of supplemental power supply, demand side resources, or rate designs to reduce peak demand for short periods.

Performance-Based Regulation: *See Incentive Regulation.*

Plant In Service: The cost of land, facilities, and equipment used to produce and deliver power as recorded on the utility's accounting records.

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 the 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.

Price Cap: A method of setting a utility distribution company's rates whereby regulators establish a maximum allowable price level. Flexibility in individual pricing is allowed in some cases, and where efficiency gains can be encouraged and captured by the company.

Program Administrator Cost Test (PACT): A measure of energy efficiency cost-effectiveness that looks only at the costs paid by the utility or non-utility program administrator, and only at benefits measurable in the revenue requirement of the utility. Also called the Utility Cost Test (UCT).

Prudence Review: The process by which a regulator determines the prudence of utility resource decisions. If a cost is found imprudent, it may be disallowed from rates. While retrospective, prudence reviews are typically determined in the bases of the information available to decision makers at the time the decision was made.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

Public Utility Regulatory Policies Act of 1978 (PURPA): This statute requires states to examine ratemaking standards, implement utility efficiency programs, and create special markets for co-generators and small producers who meet certain standards.

Q

Qualifying Facility: A cogeneration or renewable resource meeting the standards of PURPA and selling its output the utility pursuant to a PURPA compliant tariff.

R

Rate Base: The total investment used to provide service, including working capital, but net of accumulated depreciation.

Rate Case: A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Rate Impact Test (RIM): A test of energy efficiency cost-effectiveness that measures whether all utility consumers, including non-participants, receive lower rates as a result of implementing a efficiency measure.

Rate of Return: The overall cost of capital for a utility, weighting the cost of debt and the return on equity according to its capital structure.

Real-Time Pricing: Establishing rates that adjust as frequently as hourly, based on wholesale electricity costs or actual generation costs. Sometimes called Dynamic Pricing.

Regional Transmission Organization (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, the Midwest Independent System Operator, the Southwest Power Pool, the New York ISO, and the California ISO (CAISO).

Regulatory Asset: A utility investment that is allowed in rate base, but for a non-physical item determined by the regulator to be appropriate for recovery from consumers. Incentive awards for meeting performance requirements can create a regulatory asset until collected from consumers.

Regulatory Lag: The lapse of time between a petition for a rate increase and formal action by a regulatory body.

Renewable Portfolio Standard (RPS): A regulatory requirement that utilities meet a specified percentage of their power supply using qualified renewable resources.

Renewable Resources: Power generating facilities that use wind, solar, hydro, biomass, or other non-depletable fuel sources. In some states, qualified renewable resources exclude large hydro stations or some other types of generation.

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 15-20 percent reserve capacity was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to 10 percent or even lower.

Restructuring: Replacement of vertically integrated electric utilities with competing sellers of electricity, leaving the utility as a distribution-only company. Restructuring allows individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility.

Retail Wheeling: The process of moving electric power from a point of generation across third-party-owned transmission and distribution systems to a retail customer. In most cases, owners of power must pay transmission fees to system through which they wheel. Also called Direct Access.

Return on Equity: The profit rate allowed to the shareholders of an investor-owned utility, expressed as a percentage of the equity capital invested.

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 this document, revenue requirement and cost of service are synonymous.

Rosenfeld: A unit of energy efficiency equal to 3 billion kilowatt-hours per year, the approximate annual output of a 500 megawatt coal-fired power plant. Named for Arthur Rosenfeld, longtime member of the California Energy Commission. *(See Negawatt.)*

S

Seasonal Rates: Rates that are higher during the peak-usage months of the year.

Self-Generation: A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises.

Shaping: Scheduling and operation of controllable generating resources to offset the changing output levels from variable sources of power such as wind.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs. Also known as system lambda.

Smart Grid: An integrated network of sophisticated meters, computer controls, information exchange, automation, and 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 and the meter.

Societal Cost Test (SCT): A measure of energy efficiency cost-effectiveness that considers all costs and benefits, including non-monetized environmental costs and benefits. *(See Total Resource Cost Test.)*

Spinning Reserve: Unused, quickly accessible generating capacity available from units that are already connected to and synchronized with the grid to serve additional demand.

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.

Straight Fixed Variable (SFV) Rate Design: 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.

Stranded Costs: Fixed or sunk costs to be paid to the incumbent utility under restructuring when prudently incurred costs become uneconomic in a competitive market, such as the difference between the market value and book value of a power plant. Whether a utility is entitled to stranded cost recovery is usually a judgment call for regulators.

T

Tariff: A listing of the rates, charges, and other terms of service for a utility customer class, as approved by the regulator.

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.

Therm: A unit of natural gas equal to 100,000 Btu. The quantity is approximately 100 cubic feet, depending on the exact chemical composition of the natural gas.

Time-of-Use (TOU) Rates: Rates that vary by time of day and day of the week.

Total Resource Cost Test (TRC): A measure of energy efficiency cost-effectiveness that looks at all economic costs and benefits of a measure, including non-energy benefits and quantifiable environmental costs, regardless of who pays or receives them.

Total Service Long-Run Incremental Cost (TSLRIC): A forward-looking measure of the cost to provide service of a newly developed utility system. It considers all facilities and services, including administration, management, hardware, software, labor, fuel, and other elements of cost. It is used to determine if regulated prices exceed the cost a new entrant would face to offer competing service.

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. *(See Adjustment Clauses.)*

U

Undergrounding: A program for relocating existing overhead transmission or distribution lines below ground. The cost is usually split between the utility and the municipality that requires it.

Used and Useful: A regulatory concept — often triggered when plant is first placed in service, but applicable throughout the life of the plant — for determining whether utility plant is eligible for inclusion in a utility's rate base. While different state courts have interpreted the concept differently, generally used means that the facility is actually operated to provide service, and useful means that without that facility, service would either be more expensive or less reliable.

V

Value-Based Rates: Rates that are based on the cost a consumer would otherwise incur to obtain the same service some other way — for example, installing a stand-alone generator to produce their electricity.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. *(See Short Run Marginal Cost.)*

Vertically Integrated Utility: A utility that owns its own generating plants, transmission system, and distribution lines, providing all aspects of electric service.

Volt: The unit of measurement of electromotive force. Typical transmission level voltages are 115 kV, 230 kV and 500 kV. Typical distribution voltages are 4 kV, 13 kV, and 34 kV.

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.

W

Watt: The electric unit used to measure power. Kilowatt = 1,000 watts. Megawatt = 1,000,000 watts.

Watt-Hour: The amount energy generated or consumed with one watt of power over the course of one hour. *(See also Kilowatt-Hour.)*

Weatherization: A process or program for increasing a building's thermal efficiency. Examples include caulking windows, weather stripping, and adding insulation to the wall, ceilings, and floors.

Working Capital: Amount of cash or other liquid assets that a utility must have on hand to meet the current costs of operations until such time as it is reimbursed by its customers.

*Much of this glossary was adapted from **The People's Power Guide**, People's Organization for Washington Energy Resources, 1982. It was augmented with definitions from the National Regulatory Research Institute, the U.S. Department of Energy, and other sources.*

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts that focuses on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to government officials on a broad range of energy and environmental issues. RAP has deep expertise in regulatory and market policies that promote economic efficiency, protect the environment, ensure system reliability, and fairly allocate system benefits among all consumers. We have worked extensively in the US since 1992 and in China since 1999, and have assisted governments in nearly every US state and many nations throughout the world. RAP is now expanding operations with new programs and offices in Europe, and plans to offer similar services in India in 2011. RAP functions as the hub of a network that includes many international experts and is primarily funded by foundations and federal grants.

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