

A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets

**May 2002
Version 2.0**



**U.S. Department of Energy
Federal Energy Management Program
Office of Energy Efficiency and Renewable Energy
Washington, D.C.
www.eren.doe.gov/femp**

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or Battelle Memorial Institute.

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC06-76RLO 1830

Printed in the United States of America

**Available to DOE and DOE contractors from the
Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831;
prices available from (615) 576-8401.**

**Available to the public from the National Technical Information Service,
U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161**



This document was printed on recycled paper.

A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets

W.M. Warwick

July 2000
Revised May 2002

Prepared for
the U.S. Department of Energy
Federal Energy Management Program
under Contract DE-AC06-76RLO 1830

Pacific Northwest National Laboratory
Richland, Washington 99352

Contents

Foreword.....	v
Summary.....	vi
Acronyms and Abbreviations	viii
1.0 Introduction.....	1.1
1.1 Background – The U.S. Government, the World’s Biggest Energy Customer	1.2
1.2 Overview of this Primer	1.3
2.0 A Utility Defined	2.1
2.1 Types of Utilities	2.1
2.2 Utility Functions.....	2.2
3.0 Generation.....	3.1
3.1 Major Generator Designs.....	3.1
3.2 Plant Efficiency	3.4
3.3 Plant Construction and Operating Costs.....	3.4
3.4 Plant Selection and Dispatch	3.6
3.5 Utility Planning and Generating Reserve Margins.....	3.8
4.0 Transmission and Distribution.....	4.1
4.1 Transmission.....	4.1
4.1.1 Control Centers	4.2
4.1.2 Reliability and Outages	4.3
4.1.3 Adequacy, Reserve Margins, and System Reliability	4.5
4.1.4 Ancillary Services	4.6
4.2 Distribution and Customer Service.....	4.7
4.2.1 Service Offices	4.8
4.2.2 Outage and Repair Service.....	4.8
4.2.3 New Connection and New Service Requests	4.8
4.2.4 Metering and Billing	4.9
4.2.5 Marketing.....	4.10
4.2.6 Energy Efficiency and other Demand Management Services.....	4.10
4.2.7 Renewable Energy Resource and R&D Programs.....	4.10
4.2.8 Public Benefits Programs.....	4.10
4.2.9 Wholesale Customer Services.....	4.10
5.0 Utility Operation Under Regulation.....	5.1
5.1 Why Regulation?.....	5.1
5.2 Power Pools and Regional Power Markets.....	5.1
5.3 Utility Rates and Costs	5.2
5.3.1 Rate of Return	5.2
5.3.2 Fixed Costs.....	5.4
5.4 The Setting for Rate Setting	5.8
6.0 What is Deregulation?.....	6.1
6.1 Why Deregulation? A Historical Perspective.....	6.1
6.1.1 A Digression into Natural Gas Deregulation	6.1
6.1.2 Back to Electric Industry Restructuring.....	6.4
6.2 Utility Functions after Industry Restructuring.....	6.6

6.2.1	Power Exchanges, Pools, and Wholesale Markets.....	6.6
6.2.2	Plant Selection and Dispatch in a Power Exchange.....	6.9
6.2.3	Transmission Under Deregulation.....	6.11
6.2.4	Transmission Access Under Deregulation.....	6.11
6.2.5	New Institutions: ISOs and RTOs.....	6.13
6.2.6	Reliability and Reserve Margins.....	6.15
6.2.7	Ancillary Services.....	6.15
6.2.8	Tariff Administration and Back Office Functions.....	6.15
6.2.9	Billing, Settlement, Dispute Resolution.....	6.16
6.2.10	Planning.....	6.16
6.2.11	Distribution.....	6.17
6.3	Customer Services after Deregulation.....	6.17
6.3.1	Service Offices.....	6.17
6.3.2	Outage and Repair Service.....	6.18
6.3.3	New Connection and New Service Requests.....	6.18
6.3.4	Marketing.....	6.18
6.3.5	Metering and Billing.....	6.18
6.3.6	Energy Efficiency and other Demand Management Services.....	6.19
6.3.7	Renewable Energy Resource Programs.....	6.20
6.3.8	The Texas Exception.....	6.20
7.0	Coping with Utility Restructuring– Guidelines for Federal Customers.....	7.1
7.1	Recap – What Does Utility Restructuring Mean to Me?.....	7.1
7.1.1	What has been deregulated?.....	7.1
7.1.2	Setting the Cost of Energy - Wholesale.....	7.2
7.1.3	Setting the Cost of Energy – Retail.....	7.2
7.1.4	Setting Delivery Costs – Wholesale and Retail.....	7.2
7.1.5	Other Retail Charges.....	7.3
7.1.6	The Bottom Line.....	7.3
7.2	Guidelines for Coping – A 10-Step Program.....	7.3
7.2.1	Step One – Data Collection.....	7.3
7.2.2	Step Two – Review Your Utility Bills.....	7.4
7.2.3	Step Three – Reschedule Major Energy-Using Activities.....	7.4
7.2.4	Step Four – Assess Energy Price and Use Trends.....	7.5
7.2.5	Step Five – Assess Energy Efficiency Potential.....	7.5
7.2.6	Step Six – Assess New Technologies.....	7.6
7.2.7	Step Seven – Monitor Renewable Resource Developments.....	7.7
7.2.8	Step Eight – Develop a Price and Supply Risk Management Plan.....	7.8
7.2.9	Step Nine – Institutionalize Energy Management.....	7.9
7.2.10	Step Ten – Develop an Energy Management Plan and Strategy.....	7.9
8.0	How Does Deregulation Affect Me, the Federal Energy User?.....	8.1
	Glossary.....	A.1

Figures

1.1	This map shows the status of electric utility deregulation in each state in the country	1.1
1.2	The U.S. Government is the largest user of energy in the world	1.2
1.3	Total Federal Building and Facility Net Energy Use.....	1.2
2.1	The “text book” image of a traditional utility is one that owns all of the generation resources it needs and controls all of its own transmission to meet the needs of its customers	2.3
3.1	A thermal generator creates electricity by using heat from the burning of fuels or nuclear energy to create steam which turns a turbine, which rotates a generator shaft through opposing magnetic fields	3.1
3.2	Coal, nuclear, and hydroelectric plants have all been used to provide significant amounts of U.S. base load capacity	3.2
3.3	Schematic of a gas turbine plant, known as a simple-cycle combustion turbine or simply combustion turbine plant.....	3.3
3.4	Schematic of a combined-cycle combustion turbine plant, which combines a steam generator and gas turbine	3.3
3.5	Peaking plants might be compared to a beachfront hotel	3.5
3.6	Load Profile and Load Duration	3.6
3.7	To ensure a reliable power supply, power generators operate some power plants around the clock.....	3.7
3.8	The oil embargo of the 1970s prompted the government to pass PURPA and to promote use of alternative fuels including geothermal, wind, solar, and the burning of wood and municipal waste	3.10
3.9	The hydropower dams of the Columbia River Basin are mostly run-of-river projects.....	3.12
4.1	The transmission grid moves wholesale power from generators to distributors.....	4.1
4.2	Power plants have almost always been located away from the loads they serve.....	4.2
4.3	This photo highlights the key features of a control center	4.3
4.4	The 10 reliability regions of the North American Electric Reliability Council	4.12
5.1	In a regulated utility environment, rates are designed to recover costs used to serve customers and customers are allocated to classes that each have different rates	5.4
5.2	Flat, declining block and inverted rates are three rate designs employed by utilities.....	5.6

5.3	This is an example of a simple time-of-use rate design that varies by season, with higher charges during peak demand times in summer months	5.7
6.1	A Timeline of the U.S. Natural Gas Industry in the 20 th Century.....	6.2
6.2	A Comparison of the structures of traditional and deregulated electric supply systems	6.5
6.3	Dutch Auction Example.....	6.10
6.4	Currently Proposed RTO Boundaries	6.14
8.1	As with telephone deregulation, your local utility company will continue to maintain power distribution and wiring to your house	8.2
8.2	Buying power in a deregulated market	8.3

Tables

3.1	Construction Costs of Various Generating Plants	3.4
4.1	Reliability Yardstick	4.4

Foreword

A primer, by design, simplifies complex subjects. This primer is no exception. As a result, discussions of many topics may be more black and white than is the case in reality. Further, the process of selecting topics, and summarizing and editing text all introduce a point of view. Although every effort was made to present a balanced discussion, some readers may detect an occasional bias. This is unfortunate, but unavoidable. Although this document was thoroughly researched, errors in source material, interpretation, and editing are inevitable. That said, this is a dynamic document and comments and corrections are welcome. <http://pnnl-utilityrestructuring.pnl.gov/electric/Primer/index.htm>

Comments and suggestions can be posted via the Restructuring web site or can be sent to the author directly (Mike.Warwick@pnl.gov).

Summary

The objective of the Federal Energy Management Program is to provide Federal agencies and facility managers with timely and accurate information about electric industry restructuring to facilitate wise procurement of power and appropriate decisions about energy efficiency and other energy management investments in the face of industry change. This primer is offered as an introduction to utility restructuring to better prepare readers for ongoing changes in public utilities and associated energy markets. It is written for use by individuals with responsibility for the management of facilities that use energy, including energy managers, procurement staff, and managers with responsibility for facility operations and budgets. The primer was prepared by the Pacific Northwest National Laboratory (PNNL) under sponsorship from the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP). The impetus for this primer came from the Government Services Administration who supported its initial development.

Summarizing a subject this complex, even in the context of this simplified Primer, is challenging. Following is a list of highlights; these concepts are more thoroughly described in the following chapters. Terms are defined in an extensive glossary provided at the end of the report.

- The historic practice of providing consumers with electricity from a monopoly provider is not as efficient economically as it used to be due to the growth in independent power plant developers and competitive wholesale electricity markets. Giving retail customers the opportunity to choose their power supplier is expected to stimulate markets to reduce power costs and increase power products and services.
- There is a legacy associated with traditional utility practices that requires a transition period before power markets are truly open and competitive. The procedure and schedule for transitioning to competitive retail electricity markets is up to each state. Roughly half of the states have adopted a schedule for deregulation to date.
- Changing how retail consumers purchase power requires changes throughout the industry. Now that this process has been launched, the industry is restructuring itself to adapt to competition. The path forward is not fully known, but will involve existing utilities selling off their power generators as well, perhaps, as transmission lines. At a minimum, the operation of individual utility transmission lines will be taken over by third-party operators who will run them as a single, integrated system to serve competitive regional wholesale power markets.
- Retail power sales to consumers are being taken over by a variety of new power suppliers, many of which are subsidiaries of utilities based in other states. These new suppliers are not able to offer significant bill savings under most state transition rules (although they are offering new services including power from renewable resources). Most customers continue to receive power from the local utility on so-called default service rates that continue to be regulated.
- Competitive power markets are based on bids by generators into a single market, generally on an hourly basis. Market prices have been volatile. Prices are expected to continue to be volatile and

may become more so, unless new generation and transmission can be constructed to meet rising power demand. Fortunately, planned generation additions appear to be adequate to meet expected demand for the rest of the decade. Unfortunately, these new plants may not prevent spot shortages in certain areas or during high-use periods. Also, transmission construction is not keeping pace with either new plant additions or demand growth. This may result in increased transmission costs, outages, or both. This situation may continue for several years, as it takes roughly seven years to site and build new transmission lines.

- Utility-sponsored energy management programs are being phased out in the face of deregulation. Customer-funded programs operated by third parties are replacing many of these programs and new power suppliers are offering their customers' free energy audits and other energy management services, often for a fee. Some states have adopted utility fees that are used to fund energy-efficiency programs. An independent body, not the utility, often manages these funds.
- In the face of competition for electricity supplies, Federal agencies are required to solicit competitive proposals from alternative suppliers. The GSA and DESC aggregate the energy needs of Federal agencies in every state that deregulates. These GSA and DESC aggregation pools provide an easy energy purchasing option for individual Federal agencies and facilities.
- As deregulation and industry restructuring evolves, new issues will emerge. One of these is reliability. Another is the role customer-owned generators can play in managing volatile power prices.
- The best way to navigate the changing currents of utility deregulation and restructuring is to have a plan and an energy management team. It will take some work to pull together an Energy Management Team and develop an Energy Plan or Strategy, but this will pay off in the long run.

Up-to-date information on the status of deregulation in each state and updated versions of this primer are available on the FEMP restructuring web site:

<http://pnnl-utilityrestructuring.pnl.gov/electric/Primer/index.htm>

If you find this primer to be of value or if you have corrections, comments, or criticisms concerning this primer, restructuring, or FEMP, please send them to us via the web site, or to the author directly (Mike.Warwick@pnl.gov).

Acronyms

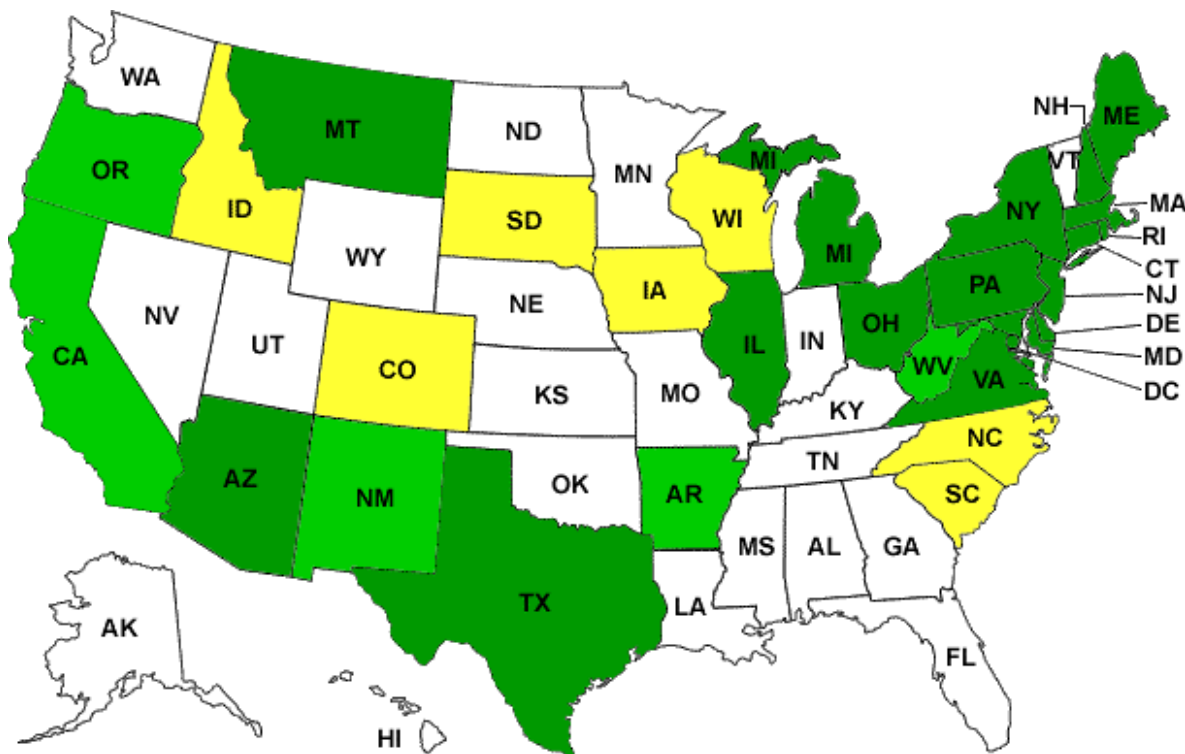
BTU	British thermal unit
COB	California-Oregon border
CCCT	combined-cycle combustion turbine
CT	combustion turbine
DESC	U.S. Department of Defense's Defense Energy Service Center
DOE	U.S. Department of Energy
E&P	exploration and production
ERCOT	Electric Reliability Council of Texas
EWAG	exempt wholesale generators
FERC	Federal Energy Regulatory Commission
FOB	freight on board
FPC	Federal Power Commission
G&T	generation and transmission
GSA	General Services Agency
GW	gigawatt
IGCC	integrated gasified combined cycle plants
IOU	investor-owned utilities
IPP	independent power producers
ISO	Independent System Operator
ITC	independent transmission companies
KWh	kilowatt hour
MAAC	Mid-Atlantic Coordinating Council
MCP	market clearing price
MMP	market marginal price
MW	megawatt
NE Pool	New England Power Pool
NERC	North American Electric Reliability Council
NY Pool	New York Power Pool
OH	operating hour
PBR	performance-based regulation
PJM	Pennsylvania, [New] Jersey, and Maryland Pool

PMA	DOE's power marketing administrations
PNNL	Pacific Northwest National Laboratory
POU	publicly owned utility
PSC	Public Service Commission
PUC	Public Utilities Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facilities
RPS	renewable portfolio standard
RTG	Regional Transmission Group
RTO	regional transmission organization
TOU	Time-of-use
TVA	Tennessee Valley Authority
USPS	U.S. Postal Service
VA	Veterans Administration
WSCC	Western Systems Coordinating Council

1.0 Introduction

Until recently, utility procurement has been fairly simple. First, the local utility sets a price, called a *rate* or *tariff*. Next, it meters the energy used and sends the customer a bill based on the rate. Finally, the customer pays the bill. Although most local utilities work with facility staff to better manage **energy use**, there is little a facility manager can currently do to reduce the **cost** of the energy commodity or its delivery. Facility managers can participate (or *intervene* to use utility jargon) in the regulatory process through which rates are set, but individual consumers have little influence over final prices.

Now, however, this structure is undergoing a profound change. The energy industry is in the midst of a metamorphosis that will affect all electricity and natural gas consumers. State legislators and utility regulators are letting consumers choose among a variety of new energy suppliers on the basis of competitive prices and products (see Figure 1.1). This trend, called *deregulation* or *restructuring*, is the subject of this primer, which was prepared by the Pacific Northwest National Laboratory under sponsorship of the U.S. Department of Energy's Federal Energy Management Program.



Yellow - Completed studies of investor-owned utilities (power providers), not pursuing further action at this time.
White - Continuing to monitor restructuring investor-owned utilities (power providers), not pursuing further action now.
Light Green – enacted legislation to implement investor-owned utility restructuring, but the transition not yet begun or suspended.
Medium Green – Transition to restructuring begun, are implementing competitive electric utility market for investor-owned utilities (includes Dist. of Columbia)
Dark Green – Have functioning competitive electric utility markets for investor-owned providers, allowing all customers choice without stranded cost or other surcharges.

Figure 1.1. This map shows the status of electric utility deregulation in each state in the country.

1.1 Background – The U.S. Government, the World’s Biggest Energy Customer



Figure 1.2. The U.S. Government is the largest user of energy in the world.

The U.S. Government is the largest user of energy in the world. Energy typically makes up about 50% of facility operating costs (Figure 1.2). The Federal government owns and leases thousands of facilities. It is the largest user of energy in the United States (and in the world), using about 2% of all of the electricity and natural gas sold annually in the United States. Consequently, effective management of energy is a critical component of government efficiency. There are over 150 individual agencies within the U.S. government. The largest energy user is the military, accounting for over two-thirds of total federal energy use (see Figure 1.3). Most civilian agencies are provided with energy through arrangements made by the General Services Administration (GSA). A few civilian agencies make their own energy supply arrangements, including the U.S. Department of Energy (DOE), the Veterans Administration (VA), the Bureau of Prisons, and the U.S. Postal Service (USPS).

Federal government rules and regulations governing energy and energy service procurement are similar for all federal agencies. Nevertheless, energy procurement and management practices vary across agencies. Some agencies manage their purchases on a geographic or regional basis; others follow operational or organizational divisions. Key to the process in all agencies is the individual facility manager or energy management team, our intended audience.

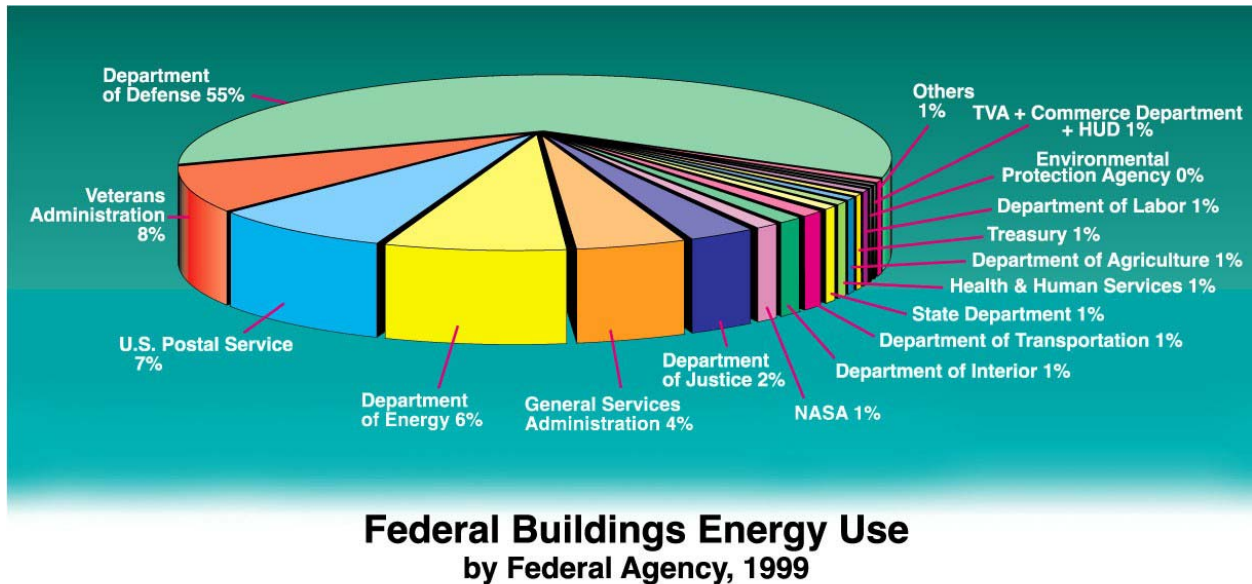


Figure 1.3. Total Federal Building and Facility Net Energy Use. In 1999, the U.S. Government used 336 trillion Btus of energy. The U.S. military accounted for 65% of total federal use. (Annual Report to Congress FY 99)”>

1.2 Overview of this Primer

This primer is offered as an introduction to utility restructuring, competitive energy markets, and new options for energy management. The intent is to better prepare readers for upcoming changes in the utility industry. The primer is written for use by individuals with responsibility for the management of facilities that use energy, including energy managers, procurement staff, and managers with responsibility for facility operations and budgets. Although the deregulation process has been underway in the natural gas industry for over a decade, this primer focuses on electric power because electricity costs are greater than gas costs for most agencies and because electric utility operations and rates are much more complex. As a result, electric utility restructuring will have a much greater impact on facility energy costs and operations. Further, deregulation is expected to lead to fundamental changes in the production, delivery, and use of electricity, and potentially natural gas. Nevertheless, comments made about electric utilities and the restructuring of electric markets generally apply to natural gas customers as well.

Chapter 2 describes utilities. Chapter 3 describes generation. Chapter 4 describes transmission. Chapter 5 describes utility operation under regulation. Chapter 6 describes deregulation and restructuring. Chapter 7 gives Federal customers guidelines for coping with restructuring. Chapter 8 provides questions and answers about restructuring. The glossary provides comprehensive definitions of terms used in the electric utility industry, including deregulation jargon. Note terms appearing in italics in this primer are defined in the glossary.

2.0 A Utility Defined

What is a utility? Typically, a utility provides a commodity or service that is considered vital to the general public such as power, water, or natural gas. Because utility service is a vital need, it has been deemed by state and federal lawmakers to be in the public interest to regulate its provision. To prevent price gouging and encourage widespread access, the government has granted individual utilities certain monopoly rights, accompanied by the right to regulate price as well as service terms and conditions.

Historically, it has been less expensive to provide utility services to a mass market in a defined geographic territory from a single supplier because of the high cost of distribution infrastructure. Generally, an energy utility is provided an exclusive right to sell energy to retail customers in a specifically defined area, called the *service area* or *franchise territory*. Because of their monopoly status, utilities are regulated at both the state and federal levels. Federal jurisdiction is required to regulate wholesale interstate transactions whereas state regulation deals with consumer-level (retail) issues such as rates and service quality.

2.1 Types of Utilities

Utilities are defined differently by each state and in federal legislation. Generally, there are two types of utilities, private and public. Private utilities, called *investor-owned utilities* or “IOUs” for short, issue stock to investors, sell bonds, and are regulated at the state level by regulatory commissions. Regulatory commissions have a variety of names although the names Public Utilities Commission (PUC) and Public Service Commission (PSC) are the most common. These commissions, or PUCs, set the retail rates charged by IOUs for their services. Commissions also ensure that IOUs respond to customer service requests and are properly maintaining utility infrastructure.

The other type of utility is the *publicly owned utility* (or POU). POUs are member-owned cooperatives or government or municipally owned utilities. Publicly owned utilities are generally exempt from regulation by state regulatory commissions because they are assumed to have the customers’ (who are also the owners or voters) best interests in mind when setting rates and service standards. A few states do subject publicly owned utilities to regulatory oversight. There are approximately 3,200 utilities operating in the United States, roughly 200 of them are IOUs. The IOUs provide power to almost 70 percent of all consumers.

There is a third class of utilities that are, in fact, a superset of IOUs, namely holding companies. Holding companies are corporations that have subsidiary utility operations. The holding company itself is regulated at the Federal level by the Security and Exchange Commission (SEC) under provisions of the Public Utility Holding Company Act of 1935 (PUCHA). Holding companies by-pass state regulation; however, this form of ownership comes with restrictions on the number and kinds of businesses it can be involved in. Specifically, a holding company may not own subsidiaries or engage in business in more than two types of utilities, such as retail gas and electric sales.

An example of a holding company is the Southern Company. It is the corporate “parent” of five “operating companies” that are traditional retail utilities: Georgia Power, Alabama Power, Mississippi

Power, Gulf Power, and Savannah Electric. It also has subsidiaries that generate power for sale into wholesale markets and engage in energy service work. The five Southern operating companies are each subject to regulation of their operations at the state level. The division of regulation between the SEC and state commissions can be confusing and can result in differential treatment of similar utility costs between utilities within the same state. For example, the holding company may sell power to its operating companies at prices that are higher than the state would allow, but are nevertheless approved by the SEC. A similar situation holds for transmission charges as will be discussed later.

The federal government is also in the utility business through its ownership of power marketing agencies including the semi-autonomous Tennessee Valley Authority (TVA) and the four DOE power marketing administrations (PMAs): the Western Area Power Administration, the Bonneville Power Administration, and the Southeastern and the Southwestern Power Administrations. Federal PMAs generally restrict their sales to wholesale customers, typically publicly owned utilities. However, they have the authority to sell to federal and state agencies and a few very large industrial customers. Some states also have power marketing agencies. Examples include the New York Power Authority, the Lower Colorado River Authority in Texas, the Platte River Power Authority in Colorado, and the Salt River Project in Arizona.

2.2 Utility Functions

The common vision of a utility embodies three functions: 1) production (gas) or generation (electricity), 2) transmission, and 3) distribution (Figure 2.1). The popular image of a utility is a company that has its own generation, transmission, and distribution and exists as somewhat of an island among similarly situated adjacent utilities. The fact is that only a small fraction of the 3,200 or so electric utilities perform all three functions and virtually no utility exists in isolation. Most of the major IOUs do own generation, transmission, and distribution; however, very few of these own enough generating resources to meet all of their needs. Very few of the POUs own their own generation or transmission. Instead, they rely on other publicly owned generation and transmission (G&T) utilities or IOUs to provide those functions for them. As a result, the vast majority of utilities rely on power purchases from others. Purchased power is transmitted, or *wheeled*, from remote generators across the transmission grid to local utility substations connected to distribution lines that serve end user loads.

The various utility functions are being deregulated to different degrees. Similarly, industry restructuring affects utility functions in different ways. Discussions of the utility generation, transmission, and distribution functions are provided in the next two chapters.

Structure of the Traditional Utility

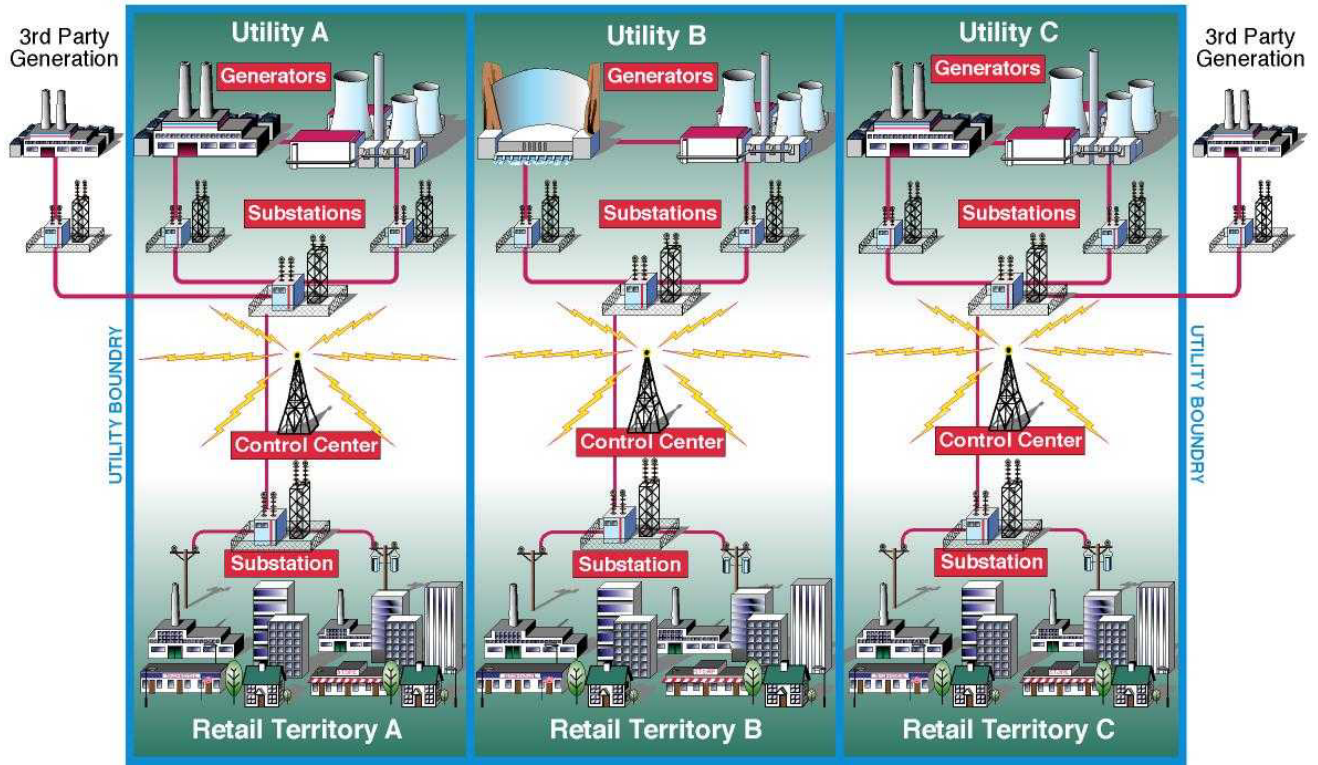
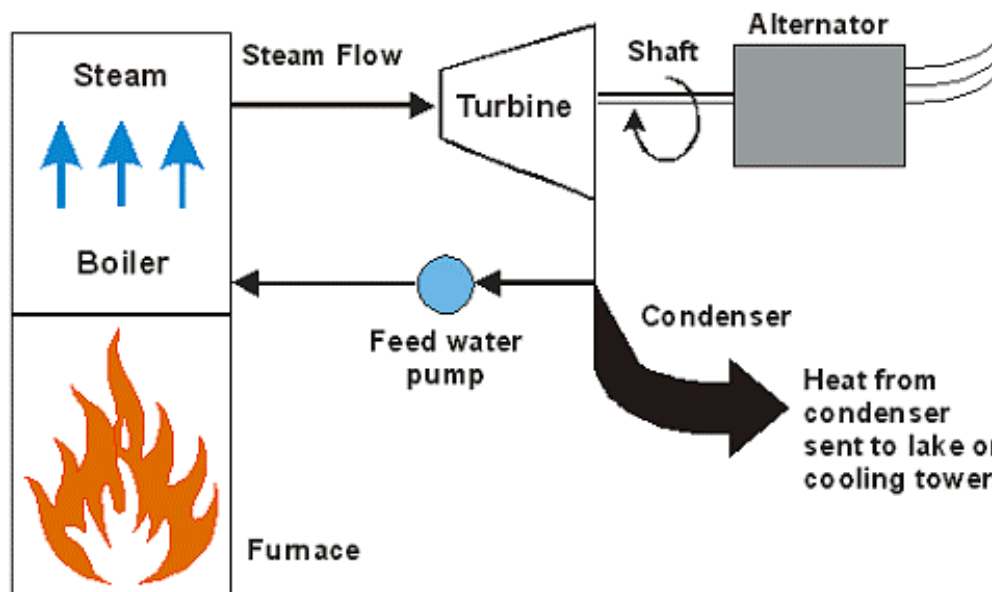


Figure 2.1. The “text book” image of a traditional utility is one that owns all of the generation resources it needs and controls all of its own transmission to meet the needs of its customers. In reality, even in a regulated environment, most utilities buy power from generation and transmission utilities and rely on power wheeled across the transmission grid. This transmission is usually controlled by control centers operated by major regional utilities.

3.0 Generation

Generating electricity has been the primary function of electric utilities since their creation. Electricity can be generated through a wide variety of processes, although far and away the most common is by the rotation of a generator shaft, or *rotor*, through opposing magnetic fields. Shaft rotation induces the flow of electricity in the generator. Power can be either direct or alternating current (DC or AC). Power is delivered to consumers in the United States as alternating current, so shaft rotation literally turns an alternator rather than a generator (Figure 3.1).



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999). From http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/fig3c.html

Figure 3.1. A thermal generator creates electricity by using heat from the burning of fuels or nuclear energy to create steam which turns a turbine, which rotates a generator shaft through opposing magnetic fields. The waste heat can be released through a cooling tower or used in cogeneration applications in factories.

An external energy source, or *prime mover*, is required to rotate a generator shaft, and that can come from a wide variety of sources.

3.1 Major Generator Designs

There are four major power plant designs based on the primary source of energy. These are water turbines, reciprocating engines, steam turbines, and gas turbines.

Hydropower plants direct water flow against turbine blades attached to one end of a generator rotor. When the water turns the turbine, it also turns the rotor and electricity is generated. Hydropower plays a

vital role in the nation's electric generation portfolio; however, due to siting challenges, there are no plans for additional large-scale hydropower developments in the United States. Consequently, new generation is expected to come from thermal power plants, or power plants that burn fuel or produce steam to turn the alternator.

Engine generators, or motor-generator sets, or simply, *gen-sets*, use a reciprocating engine as a prime mover to turn the alternator. Reciprocating engines are identical in design to those in automobiles and trucks. In fact, the diesel engines used in semi-trucks are common engines for small-scale electricity generation. Typically, gen-sets are fueled with diesel oil or natural gas. Gen-sets are also used by consumers for emergency power. Over the past decade, there has been a dramatic increase in the number of gen-sets installed, particularly in large commercial and industrial settings. These are used for emergency power, especially for sensitive computer operations, as well as for *co-generation*, or *combined heat and power (CHP)* applications.

The most common thermal power plant design uses a steam turbine (Figure 3.1). Steam for a steam generator can be produced from a variety of sources, including nuclear reactions and the combustion of fossil fuels like coal and other fuels, such as wood or solid waste. Steam is directed against the turbine blades to turn the generator rotor and generate electricity. Within the United States, only a few new coal-fired generating stations have been built in the past ten years, and no nuclear plants have been ordered since 1978 (Figure 3.2).

Gas turbines are based on jet airplane engine designs. Air is sucked into the gas turbine where it is compressed. This increases the density of the air and heats it (which increases combustion efficiency). Gaseous fuel is introduced in a combustion chamber and the resulting exhaust is used to drive a turbine attached to a generator rotor. Power plants based on this design are usually called simple-cycle combustion turbines, or simply *combustion turbines* or CTs (Figure 3.3). Steam generators are often used in conjunction with gas turbines in what are called *combined-cycle combustion turbines*, or CCCTs (Figure 3.4). Gas turbines vary in size from 30 kW for microturbines to several hundred megawatts for utility-scale plants. Gas turbine plant construction costs are roughly half that of coal-fired generators. They are also smaller and cleaner and, therefore, easier to site. Consequently, most of the new power plants built in the past decade have been gas turbines. Most gas turbines can also burn oil and oil is commonly provided as a back-up fuel in case of emergencies or if natural gas prices rise significantly.

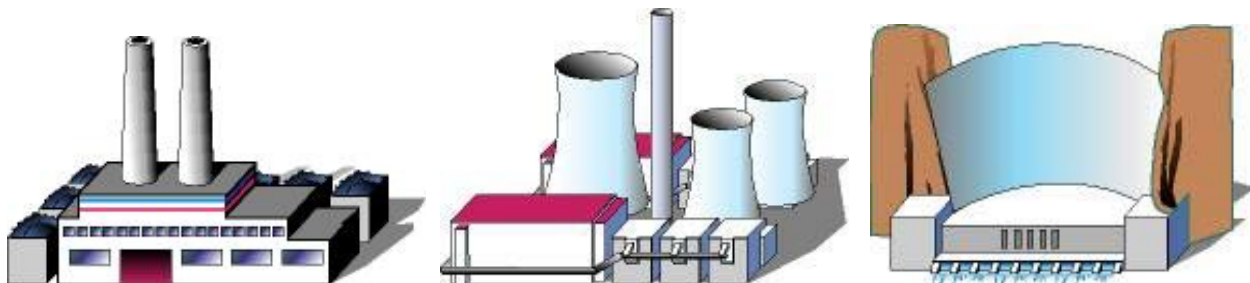
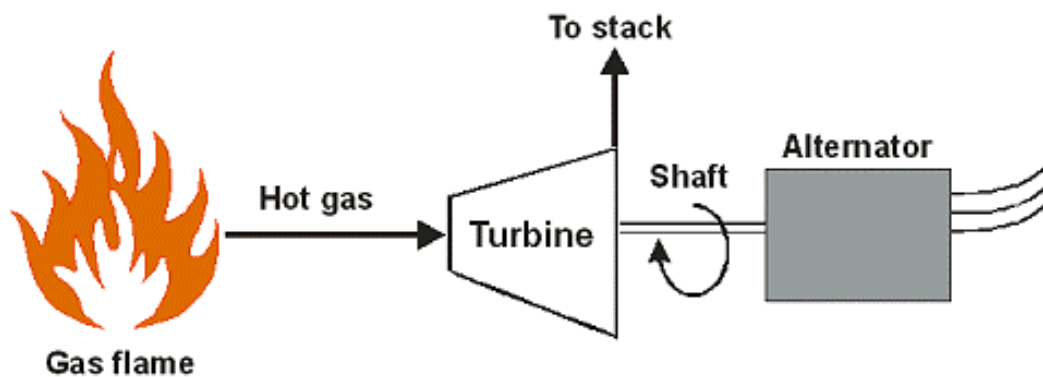
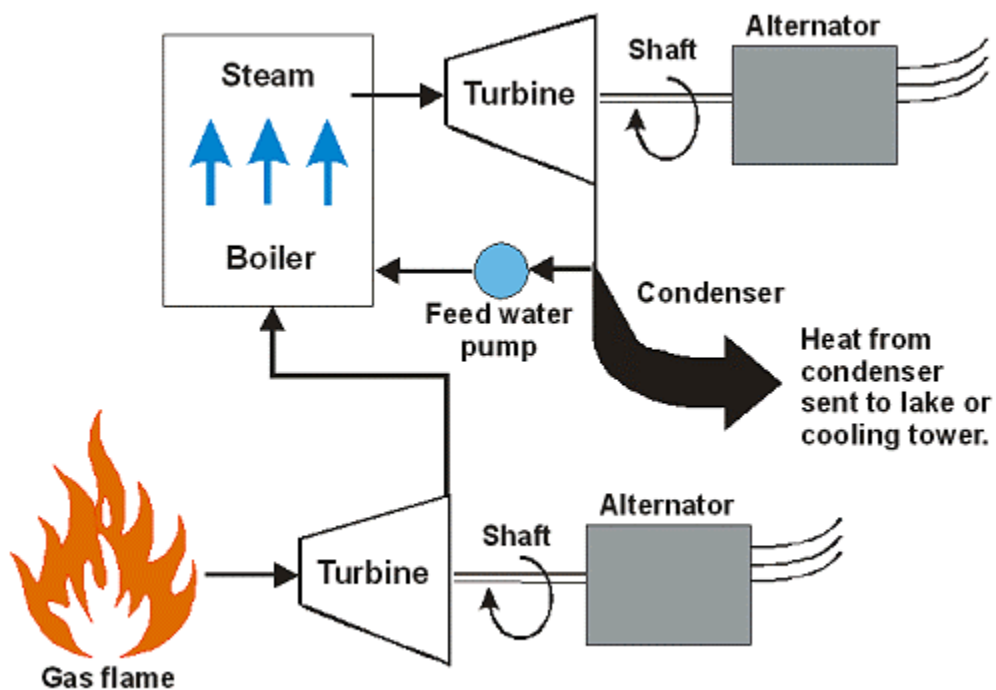


Figure 3.2. Coal, nuclear, and hydroelectric plants have all been used to provide significant amounts of U.S. base load capacity. Due to siting challenges, no new, large plants of these types have been built in the United States in several years.



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999).

Figure 3.3. Schematic of a gas turbine plant, known as a simple-cycle combustion turbine or simply combustion turbine plant.



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999).

Figure 3.4. Schematic of a combined-cycle combustion turbine plant, which combines a steam generator and gas turbine.

Although gas is almost exclusively used as the fuel source for turbines, coal is an abundant native fuel and can be converted into a gas similar to natural gas for use in gas turbines. Plants that include coal gasification are called *integrated gasified combined cycle plants*, or IGCCs. IGCC plants are cleaner burning than old-style coal plants.

Microturbines are just starting to appear in the marketplace, in niche and demonstration settings. Fuel cells are another newcomer to the marketplace. Fuel cells are unlike other generators in that there is no prime mover, rotating shaft, or alternator. Instead a chemical reaction produces electricity directly, similar to an automobile battery. Burning fuel at high temperatures generates comparatively high levels of air emissions, specifically nitrogen oxide (Nox), sulfur dioxide (Sox) and carbon dioxide (CO₂). Because fuel cell use a chemical reaction, they produce far less of these emissions and, therefore, are a preferred generating source.

3.2 Plant Efficiency

The thermal efficiency of various plant designs varies as a function of both plant design and vintage. Older plants are less fuel efficient than newer ones. The efficiency of a plant is reflected in a metric called the *heat rate*, which is expressed in terms of BTUs per kilowatt hour (kWh) of power (e.g., 9,500 BTUs/kWh). One kWh of power produces 3,412 BTUs of energy, so a plant with a heat rate of 3,412 would be perfectly efficient. This is an ideal unlikely to be achieved, although improved heat rates are the focus of intense research sponsored by DOE and industry.

The heat rate of best-of-class machines is approximately 6,500 BTUs/kWh whereas the average heat rate for all generators in service today is about 11,500 BTUs/kWh. Thus, new machines burn roughly half the fuel of the typical plant, with a similar reduction in carbon dioxide and other air emissions. Natural gas is used to fuel most new generating plants. Unlike coal and some other fuels, natural gas is processed before it is piped to customers so it is both clean and relatively uniform in terms of energy and moisture content. This is partly responsible for the high heat rate of new power plants.

3.3 Plant Construction and Operating Costs

Generating plants vary in construction cost and complexity although building any large generating plant is expensive. As a result, not all utilities build, own, or operate their own generation. The fuel for generators also varies in price. Generally, fuels with low heat content, like coal or wood waste, are inexpensive and those with high heat content, like gas, oil, and uranium, are expensive. As a result, the selection of generating plant designs requires trade-offs between construction costs and operating costs, primarily fuel. An approximate rule of thumb is that coal, which fuels 55% of U.S. electricity, is about half as expensive as gas, per Btu. For comparative purposes, the capital costs of various generating plants are provided in Table 3.1.

Table 3.1. Construction Costs of Various Generating Plants

Plant Type	Typical Plant Size	Typical New Plant Cost/kW	Efficiency Range
Reciprocating engine	2.5 kW up to 10 MW+	\$350	30-40%
Combustion Turbines	90 – 500 MW	\$300-400	30-35%
Combined-Cycle Combustion Turbines	250-1,500 MW	\$600-650	50-65%
Coal plant	1,000 MW	\$1,200	30%
Nuclear plant*	300-1,500 MW	\$2,000	na

* These figures are based on estimates as no new nuclear plants have been ordered in the United States since 1978. They reflect industry expectations for plants using updated designs, none of which have been built in the United States.

Fixed costs are predominantly the costs associated with plant construction. These costs are similar to a home mortgage that must be paid regardless of use. Although utilities are allowed to recover these costs, the costs themselves are *sunk costs* as nothing can be done to change them

Therefore, plant operating decisions (which plants to run and how long) are made based on variable costs, which are dominated by fuel costs. These controllable costs are referred to as *production costs*. Plants are generally *dispatched* (started and run) to serve loads based on production costs in what is called *merit order*, i.e., lowest production costs first. That way the least expensive plants run the most, minimizing production costs and, thus, minimizing total electricity costs. Variations in energy demand result in different combinations of power plants, and therefore, different production costs. When demand is low, only low-cost plants operate. When demand is high, such as during summer or winter peaks, almost all available generation is needed and, therefore, production costs are high (see Figure 3.5).



Figure 3.5. Peaking plants might be compared to a beachfront hotel. Some seasons of the year the hotel is booked solid and needs every room it has available to rent. Some months there is low demand for rooms at the beach and half the rooms are unused; however, the hotel still has to pay the capital costs (mortgage, taxes, etc.) to have those rooms available. The hotel charges based on paying its mortgage on the whole hotel even if some of the rooms go empty most of the year. In the same way utilities must charge to cover the capital costs they require to meet peak electrical demand from their customers.

3.4 Plant Selection and Dispatch

Prior to the oil embargoes of the 1970s, fuel prices were fairly stable and plant selection was based on expected hours of operation on an annual basis. Because retail power demand varies during the course of a day and year, a utility has to plan to meet loads during peak demand periods as well as on average. This means that if all generating plants are needed to meet peak needs, some of those plants will not be needed at other times of the day or year. Consequently, utilities select plants with the lowest generating costs, including construction and operating costs, to run at full capacity year around. These are called *base-load plants* (see Figure 3.6 and 3.7).

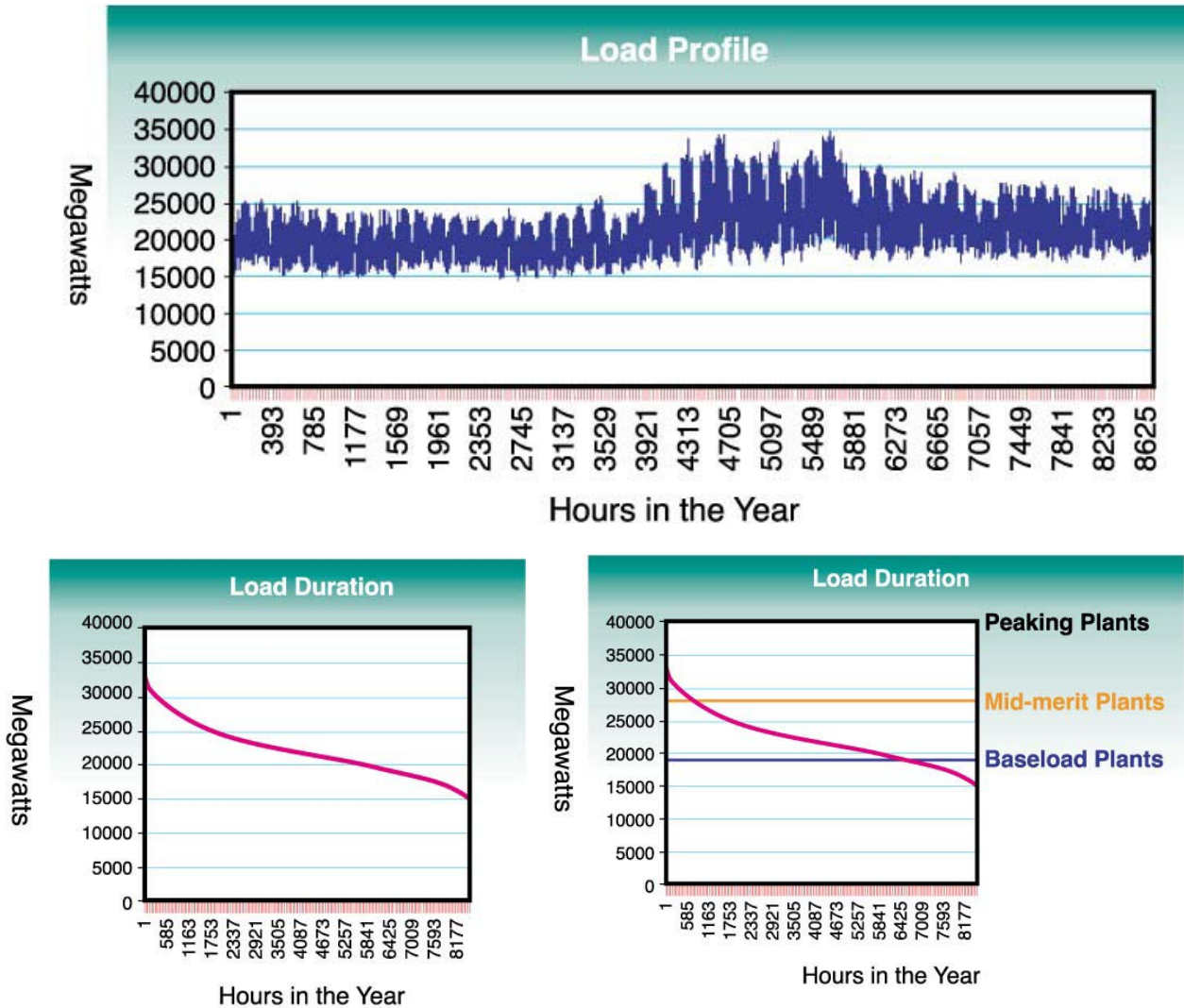


Figure 3.6. Load profile and load duration curves. The top graph shows power use chronologically for every hour in a year. The lower two graphs are typical load duration curves showing those hourly loads rank ordered from peak (highest load hour) to lowest for all 8,760 hours in a year. Anticipated new generation is primarily built to meet primarily peak demand, which is actually a very small amount of the overall load.

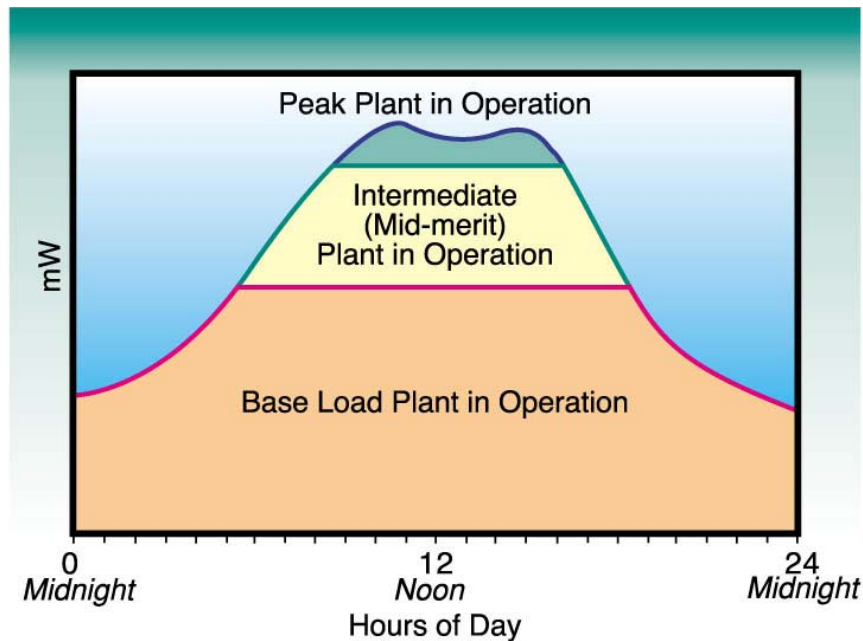


Figure 3.7. To ensure a reliable power supply, power generators operate some power plants around the clock. These plants are called base load plants. Utilities typically choose coal-fired, hydro, or nuclear plants for this continuous base-load operation because they are cheaper to run for prolonged periods. To meet demand during peak daylight hours, utilities are likely to run oil and gas-fired plants, referred to as peaking plants, which are more expensive to operate but can be started and stopped quickly. In between are intermediate or midmerit plants, which are typically combined-cycle combustion turbine plants.

Traditionally, base-load plants were fueled with coal purchased on long-term contracts, because coal typically sells for about half the price of oil or natural gas for the same heat content. Nuclear plants were added to the generating mix as a modern replacement for coal plants for several reasons. First, coal yards take up a lot of land area and are dusty and dirty in and of themselves. This makes it difficult to site coal plants. Second, coal-fired power plants require a lot of coal. This has to be shipped to the plant in rail-cars, which requires a rail line. Coal supplies can be interrupted by striking miners and railroad workers, and natural disasters that close mines or rail lines. Finally, coal-fired power plants are inefficient and produce a great deal of emissions. Coal comes from a variety of places and varies in quality, both in terms of heat and other mineral content. As a result, coal combustion produces a large quantity and wide variety of air emissions. Most of these can be captured and *scrubbed*, or filtered or precipitated out of the exhaust plume, but that is expensive, both in terms of direct costs and reduced plant efficiency. Both nuclear and coal plants are expensive to start up and shut down (called *cycling*). As a result, they are best adapted to base-load operation.

Plants used to meet peak loads do not need to run for many hours over the course of a year, generally fewer than 200 to 400 hours a year (Figure 3.5 and 3.6). As a result, utilities prefer to spend less on plant construction and use plants that can be cycled. This means the plants have to use fuels with high heat content and associated higher cost, typically oil or natural gas. Combustion turbines are comparatively easy to cycle, so they are the plant of choice for peak loads. These plants are called *peaking plants* or simply *peakers*.

In between peakers and base load plants is a class of plants called *intermediate* or *mid-merit plants*. These plants are generally based on a combined-cycle combustion turbine design and usually use a higher cost fuel than a base-load plant, usually oil or natural gas. Higher fuel costs may be offset by better heat rates than base-load plants usually obtain. Also, the closer plants run to full capacity for extended periods, the better their efficiency (and cost).

3.5 Utility Planning and Generating Reserve Margins

Utility planners take into account the way various power plant designs operate when they plan their system. When customer demand grows, it provides utility planners with an opportunity to add new, and potentially different, types of power plants to their *generation mix*. Expansion planning, as it is called, considers what time of the day and year electricity demand is growing the most and includes that in the plant selection process. If air conditioning demand is increasing, that tells system planners that more peaking plants will be needed, rather than baseload coal plants. General growth from increasing customers or new industry usually calls for new baseload plants. If new baseload plants are needed, the utility may look at changing the way some of its older, more expensive to operate, or less efficient plants are used. For example, a small coal plant may be displaced by a large new plant and rescheduled for use only during winter and summer months when average demand is higher. Oftentimes, smaller and older plants are used to provide operating reserves.

Customer demand growth is uneven and somewhat unpredictable. Nevertheless, utilities are required to provide for all customer demands, even those that may be unexpected. The amount of those reserves is set through industry standards, which are reviewed and approved by regulators. Typical reserve margins are in the 15 to 20 percent range, usually based upon the need to have power available if two of the utilities' largest plants are out of service at the same time during the system's peak.

There are several ways to estimate required reserve margins. The results vary both by technique and size of power plants. For example, if a utility has a peak demand of 8,000 megawatts and its largest plant is a nuclear unit rated at 1,100 megawatts, if that plant were to trip off line, the utility would immediately be without roughly 14% of the needed generation. A 15% reserve margin would be inadequate in that case and a higher margin would be required. Alternatively, if the largest plant were only 500 megawatts, multiple plants would have to trip off line to fall below a 15% reserve margin. Generating reserves can be provided from a variety of sources. The necessary capacity can be actual power plant capacity, or contracts for generating capacity owned by others, or it can come from demand relief/interruptible loads. Reliance on reserves from sources outside the utility's service area increases reliance on the ability of the transmission system to deliver reserves when needed. This creates another contingency that also needs to be factored into the calculation of reserve margin.

A Historical Sidenote -

The Oil Embargo and Passage of the Public Utility Regulatory Policies Act of 1978 (PURPA)



During and after the 1970s oil embargo, fuel costs were volatile and most utilities and regulators expected oil prices to continue a steady upward climb. As a result, utilities developed plants based on coal and nuclear technologies, which had construction and operating costs much higher than historic averages. At the time, these plants looked like a bargain compared to the projected future operating costs for oil- or gas-fired plants.

Utilities were also projecting continued growth in demand for electricity due to both growing population and a switch in end-use fuels from oil and natural gas to electricity because of projected petroleum price increases and potential supply disruptions. In fact the federal government encouraged fuel switching and, for a time, prohibited utilities from building new natural gas-fired power plants.

The focus on ambitious plans to construct new, large power plants created opportunities for independent power plant developers to build new, smaller scale plants that took advantage of unique power generating opportunities such as small hydropower sites, industrial co-generation, burning of municipal waste, and renewable resources such as geothermal energy, wood, wind, and in a few cases, solar. Development of these resources was contingent upon the purchase of the output by the local utility at favorable terms.

In order to encourage the development of these unique and often small-scale resources and thereby to diversify the domestic power resource base, Congress passed legislation that both allowed non-utilities to build power plants and required local investor-owned utilities to purchase the output on terms favorable to the developers, typically at current prices that were at historically high levels and for periods of 20 to 30 years. Some states enacted regulations that went further and mandated utility purchases at specific prices, regardless of need for power.

The federal legislation is found in Section 210 of the Public Utility Regulatory Policies Act of 1978 (*PURPA*). This legislation created a new legal category of power plants known as *qualifying facilities*, or QFs, and new market entrants called *independent power producers*, or IPPs. Contracts for power from QFs typically covered the life of the plant, because the only outlet for power from a QF was the local utility. Subsequently, utilities asked Congress and state PUCs to reform the power purchase requirements of PURPA. Although Congressional action is still pending, PURPA did create a new category of power producers.

Because fuel costs are volatile, many utilities, regulators, and legislators guessed wrong about the future of fuel prices, supplies, and sources in the late 1970s. A continued escalation in power demand had been predicted despite rising prices; instead, there was a sudden fall off in power demand (thanks to a significant increase in both prices and energy conservation efforts). As a result, many utilities were left with inventories of plants in the midst of construction or new plants that were now idle.

Rate problems due to excess capacity characterized the utility environment in the 1980s. In the gas industry, domestic gas exploration accelerated in the 1980s due to passage of the Natural Gas Policy Act of 1978, which removed federal price caps that had been in place since the 1950s. Decontrol, coupled with advances in the accuracy of geological characterization, resulted in an increase in natural gas production and a decline in gas prices. By the late 1980s natural gas producers found themselves unable to sell new gas on favorable terms because of restrictions by the natural gas pipeline companies due, in part, to continued federal regulation of pipeline transportation rates.

The Federal Energy Regulatory Commission (or FERC, which was created by the Natural Gas Policy Act) attempted to reduce barriers to pipeline access by third parties in Open Access Rules 436 and 500. (See chapter 6 for more on how these orders and FERC's landmark Order 636 deregulated the gas industry and paved the way for restructuring of the electric utility industry.)

Ultimately the National Energy Policy Act of 1992 authorized utilities to enter the IPP business as *exempt wholesale generators, or EWAGS*. This allowed IOUs, through subsidiaries, to develop power plants to sell power to other utilities and keep the profits for shareholders. Because EWAGs are "exempt" from price regulation, any losses have to be absorbed by stockholders as well. In other words, ratepayers are not responsible for any losses and cannot reap the rewards from any profits from EWAG investments.

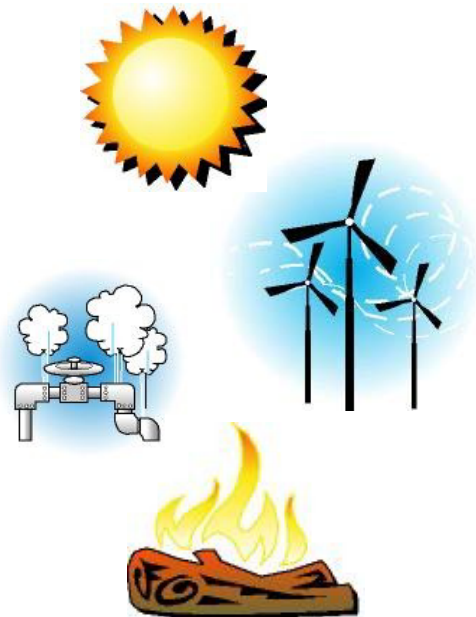


Figure 3.8. The oil embargo of the 1970s prompted the government to pass PURPA and to promote use of alternative fuels including geothermal, wind, solar, and the burning of wood and municipal waste.

A Historical Sidenote - Exceptions to the Rule



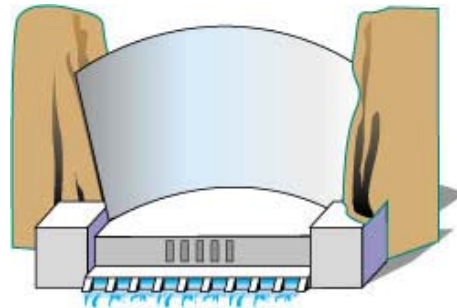
Generation provided by dams, wind, and solar energy are exceptions to the rule for generator operations for several reasons. The primary reason is that their fuel - rain, wind, and sunshine - is free. That means these plants should be dispatched whenever they can run to displace plants with purchased fuel requirements. Wind and solar power make up a small fraction of installed generation so their scheduling and dispatch is less important than that of hydropower projects.



Hydropower plants fall into two types, storage projects and run-of-river projects. Most hydropower plants have storage reservoirs, lakes behind the dams. Storage projects are favored, but they require the flooding of large areas of land. Not only is it expensive to acquire the land, land isn't always present at the best dam sites. Run-of-river projects still have dams, but they have very small lakes behind them. These lakes would be drained quickly if the water was released all at once, leaving the dam with only the normal water flow of the river to power it. As a result, run-of-river projects are operated based on a combination of the water stored in reservoirs behind the dams, water stored in the watershed as snow that will melt in warm weather, and projected rainfall. As a result, run-of-river hydropower projects are more like wind or solar power than thermal power plants. For example, the hydropower projects on the U.S. portion of the Columbia River in the Pacific Northwest are mostly run-of-river projects (Figure 3.9).

All hydropower projects are restricted by precipitation levels (snow and rain). The amount of power that can be generated by hydropower plants depends on actual precipitation plus available storage in the system of reservoirs (and in mountain snowpack). Storage behind dams is limited, so plant operators also have to release water to ensure that reservoir levels don't get too high. This balancing act creates unique challenges for planning and operating hydropower plants. Naturally, utilities want to maximize the amount of hydropower they can generate, but they don't want to drain reservoirs so low that they have no water in storage, and therefore no control over the hydropower resource. In addition, whenever it rains, even in the summer, the amount of water in the system changes. Similarly, if rainfall is less than normal, less power will be available. This is very important for utilities that have large portions of hydropower in their system.

Utility planners cannot rely on average or typical precipitation levels to meet customer demand. If precipitation is less than normal, reservoirs will run dry before the next rainy period. At the same time, if there is more precipitation than normal, reservoirs will overflow. As a result, hydro system planners generally plan on having only as much power as can be produced from a minimum level of precipitation over an appropriate historic interval.



In the Pacific Northwest, this is called *critical water planning*. Critical water planning means that the region never runs out of power from lack of rainfall, even in drought years. It also means that whenever rainfall is greater than normal, there is surplus hydropower available. In very good water years, this means the region has abundant cheap power and can rely much less on power from more expensive alternative sources. Because power has to be generated from the region's run-of-river plants as the river flows, sometimes there is too much power produced and it is exported out of the region to adjacent states, especially California. This creates a unique "balance of trade" opportunity between the two areas, as the Northwest can sell surplus power to California during the spring rains and California can sell power to the Northwest during the dry summer months.

Although critical water planning prevents hydropower-dominated power systems from running out of power, it doesn't protect them from high power prices during drought periods. This is because utilities in the region come to depend on having low-cost surplus power available for purchase. When it isn't available, they have to pay market price for power generated by thermal power plants. If a lot of utilities find themselves in the same situation, it can drive up demand for thermal power, and consequently, power prices. Wind power is like hydropower in that it is also subject to weather patterns that vary from year to year. As wind power becomes a greater portion of the nation's generating mix, it may result in power system planning challenges similar to hydropower.



Figure 3.9. The hydropower dams of the Columbia River Basin are mostly run-of-river projects. (Map courtesy of U.S. Army Corps of Engineers.)

4.0 Transmission and Distribution

People tend to be more familiar with the distribution lines in their neighborhoods than with high-voltage transmission lines. Typically, transmission lines are located in remote areas so they can run for long distances in a straight line, as it is much cheaper to build that way. In contrast, distribution lines have to be close to the customer (Figure 4.1). Consequently, they are more numerous. In general, distribution lines are *radial*, or run away from the transmission lines to a dead end.

Power typically flows from a generator, along the transmission grid to a substation where it is transformed, or *stepped down*, to a lower voltage for distribution. The voltage reduction allows the utility to use smaller wires and shorter poles for distributing power to consumers. Power on the distribution line flows to customer homes and businesses, but it gets stepped down again as it comes off the distribution lines. Those large, round, black transformers that are mounted on the top of power poles outside homes do this transformation. If the home or business is served with underground wires, the transformer is mounted on the ground in a housing of some sort.

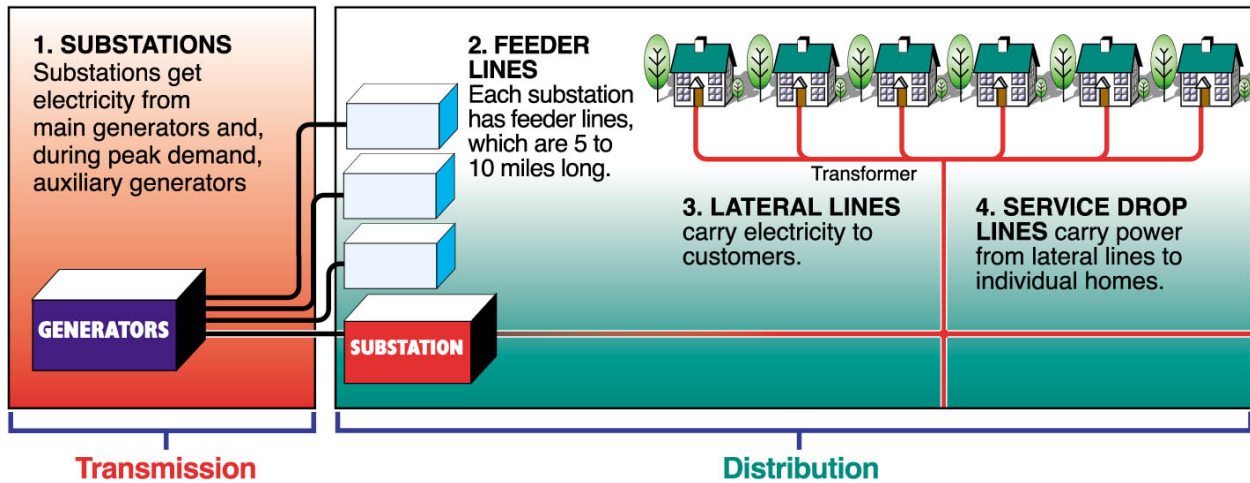


Figure 4.1. The transmission grid moves wholesale power from generators to distributors. The distribution system moves retail power from distributors to customers. Transmission will continue to be regulated at the federal level by FERC. Distribution will continue to be regulated at the state level by state commissions.

4.1 Transmission

When most people think of an electric utility they envision a company, typically associated with a major metropolitan region, that owns generating plants located far away from most of its customers. A large concentration of customers, like a metropolitan area, is called a *load center*. Power from remotely located generators travels to load centers along high-voltage transmission lines (Figure 4.2). The linkage between power plants and load centers via transmission lines is familiar to most people due to the wide swath of land associated with transmission corridors. Less obvious is that transmission lines also connect to each other forming a network, called the *transmission grid*. The combination of generation and the transmission network is referred to as a *power grid* or power system.

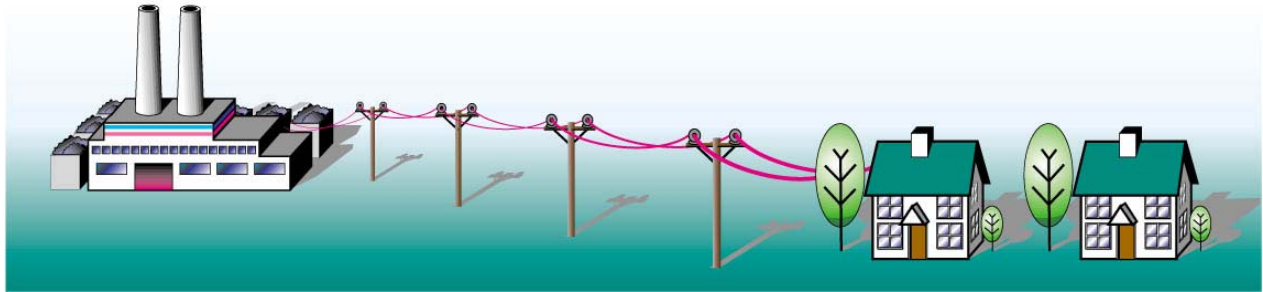


Figure 4.2. Power plants have almost always been located away from the loads they serve. The first plants were in industrial areas close to industrial coal supplies or, in the case of hydropower, along distant rivers. The first electric loads were lights in wealthy neighborhoods far removed from the industrial and shipping areas. Transmission lines tied the generation and the loads together.

Areas that are not well integrated into the power grid are called *load islands*. Load islands are usually literal islands, like Manhattan and Long Island in New York or peninsulas, such as the DelMarVa and Monterey peninsulas. These areas tend to have fewer transmission lines into them than they would if they were more centrally located on the power grid. Rapid urban growth or lagging construction of transmission can also create *load pockets* within the power grid.

4.1.1 Control Centers

Because so few retail utilities actually own and operate their own generation, they rely on other utilities, usually the largest utilities in the region, to provide for the transmission of power to them in a process called *wheeling*. Wheeling power requires the use of transmission lines that are owned by multiple utilities. This use needs to be managed so that power can be tracked as it flows from utility to utility across the grid. Utilities manage the operation of generation, transmission, and transmission maintenance from facilities called *control centers*. Power that is wheeled through a system is coordinated between adjacent control centers. Although there are over 3,000 retail utilities, there are only 140 control centers in North America.

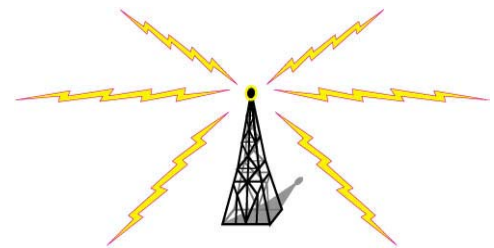


Figure 4.3 shows a typical control center, this one located in Texas. At a control center, control is provided through the computer terminals on the operators' desks. These terminals provide schedules for the operation of generators and resulting transmission loadings. They also provide real-time information so operators can verify that schedules are being followed and take corrective action when there are deviations from the schedule or if customer demand or weather is different than expected. System controllers communicate with power plant operators and transmission crews through secure computer, telephone, or radio connections.



Figure 4.3. This photo highlights the key features of a control center. On the far right is a map. Although it is too small to show these details, the map indicates the location of power plants and transmission lines under the control of the center, usually with colored lights that indicate the status of the power plant or transmission line (e.g., red for out of service). Connections to adjacent control areas are also indicated. (Photo courtesy of Electric Reliability Council of Texas [ERCOT].)

4.1.2 Reliability and Outages

When consumers think about reliability, they generally think in terms of power outages, but reliability is much more complex than that. Transmission and generation work together. Given the roles each performs, they are effectively substitutes for one another. In other words, power can be transmitted from a remote power plant to a customer, or it can be generated locally, near the customer. In the first instance, transmission substitutes for near-by generation. In the second, generation substitutes for transmission capacity.

The benefit of an extensive transmission system is that it provides access to generation across a much broader area. This allows power purchasers to hunt for lower cost power than might be available locally and for distant generators to perhaps sell their low-cost power for a higher profit. It also allows utilities to diversify the source of their purchases. However, an extensive transmission system also has costs, in addition to the expense of construction and maintenance. Reliance on power from distant power plants delivered over long transmission lines leaves a utility vulnerable to disruptions on the power lines. This has to be taken into account when the utility plans its generating reserve margins, lest it find itself with power supply contracts in hand, and no power deliveries to back them up. These are the kinds of issues that utilities must include in their generation and transmission planning and operations.

Reliability is actually composed of two elements, *adequacy* of generation and transmission capacity and *reliability* of transmission and distribution system performance. In other words, is there enough power and transmission capacity and can it be used to get power to all customers when they need it?

When consumers have a power outage, they tend to blame “the power system” or “the utility.” In fact, less than 10% of consumer outages are the result of failures of the main power grid (the generation and bulk power transmission system). About 10% are due to substation failures. The remaining 80% of outages occur in the local distribution system, caused by falling tree limbs or other vegetation, animals getting into the power lines, automobile accidents, and lightning strikes or other severe weather. Typically, distribution outages are localized. In other words, only a small area of the utility system is out of power. Major storms can knock out power to larger areas without actually bringing down the entire power grid. This is because transmission lines are built to be above or away from trees that can interfere with them, while distribution lines tend to follow along tree-lined streets in cities and towns.

Outages are measured in terms of duration and number of customers affected, or “customer-hours” of outage. Another measure, usually mislabeled as “reliability,” is the percentage of time the power system “works.” Typically, power systems work at least 99.9% of the time. This is called 3-nines power (because there are three nines in the percentage, see Table 4.1). Electronic equipment is highly sensitive to power outages and deviations in voltage and frequency (the 60 Hertz, or cycle, frequency that is characteristic of the North American electric grid). Users of sensitive electronic equipment, or even highly automated manufacturing operations, require power that is highly reliable and “clean,” or with few voltage or frequency deviations. Companies that host Internet servers typically want both “quality” power and “high-9s” power.

All the talk about high-9s power quality and the lack of “reliability” of the power system has obscured the fact that the bulk power grid is highly reliable. If distribution outages are eliminated from outage statistics, reliability at the transmission level would be in the range of 99.999%. Unfortunately, regulators are primarily interested in customer service outages and utilities normally don’t separately report outages on the transmission system versus the distribution system. Nevertheless, a system-wide (transmission level) outage usually warrants front-page coverage in the newspaper. How many of those have you seen lately? Recognizing this, some manufacturers in Silicon Valley had the local utility connect them directly to the high-voltage transmission grid.

Table 4.1. Reliability Yardstick - Typically power systems are reliable at least 99.9% of the time. Users of sensitive electronic equipment require power that is highly reliable, called “high-9s” power.

Duration of all outages/year	Reliability percentage	Number of 9s*
8.76 hours	99.9	3
0.876 hr. or 52 min.	99.99	4
0.087 hr. or 5.2 min.	99.999	5
0.0087 hr. or 31.2 sec.	99.9999	6
0.0008 hr or 3.12 sec.	99.99999	7
0.00008 hr. or .3 sec.	99.999999	8
0.000008 hr. or ~ 2 cycles	99.9999999	9
* For reference, control systems on the bulk power system typically operate no faster than 3 cycles (one twentieth of a second). Accordingly, 7-nines is about the limit for power system reliability.		

4.1.3 Adequacy, Reserve Margins, and System Reliability

Transmission systems are planned following assumptions that are similar to generation, namely, demand growth is uneven and unexpected things happen that need to be anticipated. Unlike generation, transmission is both static and fixed, as well as being long-lived. A transmission line delivers power from point a to point b. It can't direct the power itself (that is done through the operation of generation and transmission at the control center). Further, transmission lines are "lumpy." In other words, they come in only a handful of sizes. If one is too small for the job, the next size up represents a significant increase in cost and transmission capacity.

Transmission lines don't wear out, per se, so once they are built, they tend to last for decades. More significantly, obtaining rights-of-ways for transmission lines is difficult and time consuming. As a result, once a transmission corridor is established, transmission planners anticipate using it for decades to come and tend to size transmission lines to meet future growth for the foreseeable future. The extra capacity on the line provides a reserve for unanticipated events, as well as future growth; however, transmission planners have other guidelines they also follow to ensure adequacy.

When power is injected onto a transmission line, it flows through the entire network, not just from point a to point b. Using the old "electricity flows like water" analogy, it is similar to a network of irrigation canals, where the water seeks the same level no matter where it comes in or where you want it to go. A transmission line outage (for maintenance as well as unanticipated disruptions) acts like a dam on an irrigation canal, forcing the water around the blockage. If adjacent transmission lines cannot handle the power that is rerouted, safety devices will switch them off, further impeding power flows and potentially leading to cascading outages and system failure, i.e., a blackout. As a result, transmission planners and operators plan to have back-up transmission lines available just in case a line goes down. As long as there are plenty of lines, and "spares" in reserve, there will be *adequate* transmission.

Few consumers are aware of the role *generation* plays in ensuring *transmission* reliability. Electricity flows at the speed of light. As a result, electricity generation, transmission, and use are interdependent and have to be in balance from moment to moment. In other words, how electricity is generated and transmitted affects how it can be used and vice versa. Therefore it is important for all elements of the electric grid, including interactions between the grid and consumption, to be synchronized. The responsibility for this synchronization falls on generators and the transmission system operators that control them.

Generation is dynamic, whereas transmission and consumption are assumed to be essentially passive elements of the power grid. Therefore, generators are used to react to changes in electricity use and to changes in schedules for generation or transmission. For example, if a generator that was scheduled to operate doesn't, another generator somewhere else has to take up the slack. Similarly, if a transmission line is unavailable, the output of all generators will need to be changed to make sure power flows around the line that is out of service. The process involved in both cases is called *redispatch*.

Although the transmission system is designed for reliability, the location of generation on the transmission grid is part of that design. Instead of building a redundant line from remotely located power plants all the way to the urban load centers, a generator may be located at the midpoint of a transmission line. This effectively protects against transmission line failures upstream of its location. In other words,

if the transmission line upstream of the power plant fails, the power plant can increase its output to replace the power that the transmission line was carrying.

Because the transmission system's redundant transmission elements and generation location ensure its reliability, transmission planning and expansion typically accompany the addition of new power plants. This is a very important point. The last round of power plant additions was in the 1980s. These were plants constructed by utilities and paid for by rate payers under traditional regulatory schemes. These new plants were accompanied by an expansion of the transmission system within utility service areas. In retrospect, "too much" generation and transmission was built in the 1980s and that resulted in a lack of new power plants through the 1990s. We have pretty much used up the spare generating capacity from the 1980s along with the associated transmission. The consequences of this are now evident in recent power shortages and power price spikes and volatility. In the new deregulated era, construction of power plants falls largely to non-utilities. The issue of transmission planning and construction is, as yet, unresolved. This topic will be discussed further in the sections on deregulation, but it is important to note the underlying dynamics here.

4.1.4 Ancillary Services

Generators provide a variety of *ancillary services* to the transmission function, including

- regulation of voltage (i.e., the 120-, 240-, and 480-volt current at the power panel) and frequency (the 60-cycle signature for North American power systems)
- reserves (back-up energy supplies)
- reactive control (the basis for reactive charges)
- load following (exactly matching generation to consumption).

Without these services the power system would be unreliable even with adequate generating and transmission supplies. Ancillary services require few generators relative to those needed for power supply (less than 10% actually operating); however, the services these generators provide are absolutely critical. The control center provides for these services in the way it schedules and dispatches power plants. Generating reserve margins were discussed previously as a regulatory requirement to meet emergencies during peak demand periods.

Two different types of reserves are required for system reliability. The first is called *non-spinning reserve*, or *installed capacity reserve (ICAP)*. This is usually supplied by power plants that are available for operation, but sitting idle. Typically, these plants need to be capable of starting up to provide reserves within 10 minutes. Some system operators call this "10-minute reserves" as a consequence. The other type of reserve is called *spinning reserve* or *operating capacity reserve (OCAP)*. Spinning reserves are provided by power plants that are actually operating, but at less than full capacity, hence the generators, or at least the prime movers that turn them, are "spinning." Spinning reserves need to be available within 10 minutes, to ensure that adequate voltage is maintained on the system until non-spinning back up generators come on line to provide system support.

Another ancillary service is *reactive control*. Reactive power, also called imaginary power, is a creature of alternating current power systems. It is somewhat difficult to explain, but it typically results from interactions between electric motors and generators. Electric motors rotate like generators but act as if

they were working **against** the power system. That requires the power generators to work harder and burn more fuel. Thus, there are **real** costs for supplying **imaginary** power. This is why utilities charge large customers a reactive power fee in their rates. Reactive control is provided at the system level through the operation of selected generators, dedicated to this function. Out on the transmission and distribution system, reactive control is usually provided by capacitor banks.

Generation needs to match electrical demand on a moment-by-moment basis or there is a risk that certain power quality standards won't be met, specifically voltage and frequency. Industry standards are set for voltage and frequency although these standards allow for limited deviations. For example, when a large load is turned on, generators are forced to work harder, which can cause a temporary drop in voltage until the generators catch up. There are generators dedicated to providing this kind of support to the system, and they constitute a service called *automatic generator control*, or *AGC*. AGC keeps the power grid synchronized so all of the generators are working together.

A related ancillary service is one that provides the necessary energy to match generation to loads within an hour. For example, a power plant may schedule to provide 100 megawatts of energy to the system between noon and 1 PM but may actually provide 120 megawatts in the first 30 minutes and 80 the next. Because the system operator was expecting a uniform 100 megawatts of generation, he had to make up for the difference by changing how some generator operated. This could be done by controlling a specific generator or by redispatching several generators. In either case, there is a cost associated with these changes for *load following*, or *imbalance energy*. Conversely, a utility may have purchased 100 megawatts for use between noon and 1 PM and actually used 120 megawatts the first 30 minutes and 80 the rest. As a result, they may be subject to the imbalance energy charge.

Not all system operators levy imbalance energy charges. Some roll it into other charges or require power sellers to provide this service on their own. Imbalance energy charges can be a significant barrier to the construction and use of generation that is difficult to predict or schedule, such as that from wind or solar generation and distributed generators.

Failures of the bulk power system are rare. When they occur, outages are widespread and the subject of intense industry analysis. The electric industry deals with failures of the bulk power grid like the airline industry handles plane crashes. They thoroughly review what happened, and why, and change practices to prevent a future reoccurrence. These investigations are initiated by the regional industry reliability organization; these organizations form the *North American Electric Reliability Council* or NERC (see sidebar). The NERC has increased its focus on grid reliability by requiring each region to have a designated *security coordinator*.

4.2 Distribution and Customer Service

The distinction between transmission and distribution for a utility is not as obvious as the consumer might think. In fact, the industry has tried to draw a so-called bright line between the two with little success. Such a line is needed to clarify FERC and State jurisdiction over power line regulations and rates. In general, transmission lines are high-voltage lines, those with kilovolt-ampere (kva) ratings of 750, 500, 230, and 115. Distribution lines have lower voltage ratings, such as 69, 34, and 13 kva. For convenience, many in the industry refer to ratings of 115 kva and above as transmission. Things are not that simple, however, because lower voltages are often used for transmission in rural areas where power transfer

requirements are less. A functional definition is also used. Typically, transmission lines serve the bulk power system and distribution lines serve retail customers. This distinction is also compromised as large industrial customers often receive retail service over high-voltage lines.

It is not unusual in rural areas for both retail and wholesale transaction to use the same low-voltage wires. In those situations, both FERC and the state may have authority to set access terms and rates, often in conflict with each other. For example, FERC's access terms for transmission lines require open access, whereas state regulations prohibit retail access prior to deregulation. Similarly, FERC may assign different rates for transmission than states do for distribution, even when both transactions are using the same lines. Regardless, the transmission component of retail rates is generally small, typically less than 10% of the total cost of power.

The energy component of rates varies from approximately two-thirds of the bill for large customers to less than one-third for small customers. Conversely, charges associated with local utility operations compose one-half to two-thirds of most retail customers' bills. The balance of the rate pays for customer services, including maintenance and repair of the power lines, customer offices, and so on. Each of these has become an expected part of regulated utility service at the retail level. Deregulation may make some of these competitive and others non-economic. Therefore, a review of the primary distribution customer services available to retail customers is useful.

4.2.1 Service Offices

Customer service offices provide customers with a convenient way to pay bills, open and close accounts, and resolve complaints. Utilities use these offices as part of their marketing, public relations, and community involvement efforts, including meeting with customers to discuss new service requirements and promoting energy-efficiency services. Often, they are used as field offices for service crews, including meter readers and line maintenance staff. Closing customer service offices is a common cost-cutting move. As the industry restructures, this trend is likely to continue, especially as utilities merge and consolidate.

4.2.2 Outage and Repair Service

When the lights go out, consumers call the local utility for service restoration. In most cases, the utility has limited liability for outages; however, they are often required to repair equipment that may be damaged, such as a VCR damaged due to a voltage surge or to replace items spoiled due to power outages, especially refrigerated foods. This liability is typically limited to a maximum dollar amount and may be restricted to residential customers.

4.2.3 New Connection and New Service Requests

The local utility is the point of contact for connection of new facilities and for expansion of existing services. Generally, utilities are fairly generous with service connections and expansions as new customers means new power sales and distribution revenues. There are exceptions, when the customer is required to compensate the utility for services.

- Customers that are not close to distribution lines are usually charged for costs that exceed “typical” connection costs. These may be prohibitive for remote locations. Some utilities may choose not to provide a line at all, and instead offer a remote power supply option, such as a solar photovoltaic system. A lot of remote areas fall between utility boundaries. In some cases, utilities may claim a remote customer is outside their service area to avoid the additional cost of serving them.
- The local utility is also the focus for interconnection of customer-owned or on-site generation, including distributed energy resources (DER). Standards and expectations for interconnection of DER vary widely and remain an ongoing subject for negotiation within the industry. Utilities have legitimate concerns about protecting the safety of their workers and other retail customers from “stray” voltage from DER devices that may be operating when a power line is supposed to be down. On the other hand, the restrictions utilities want to impose on owners of DER devices are often excessively expensive and potentially defeat the purpose of using DER for back-up power during outages.
- Some customers want to have service drops (connections to the distribution network) from 2 or more different substations to ensure a reliable power supply. This is typically a value-added (extra cost) service.
- Finally, customers that want the ultimate in system-supplied reliability may want to be connected directly to the high-voltage transmission grid. This requires a substation at the customer site, which can be expensive. This is also a value-added (thus extra cost) service, providing the utility even allows it.

4.2.4 Metering and Billing

Metering and billing are integral to the provision of electric service; in essence, the power meter is the utility’s cash register. Modern utility meters are capable of many functions that could help customers manage energy more wisely. These new meters are significantly more expensive than traditional ones and usually require replacement of traditional meter reading and billing systems at considerable utility expense. As a result, some utilities stay with traditional meters to keep rates low. Large customers and customers with multiple locations can benefit from more modern metering. Unfortunately, the slow pace of adoption of advanced metering may limit the ability of these customers to upgrade or to take advantage of all the available features.

Similarly, some customers would like the ability to have all utility bills arrive or come due on the same day. Present utility meter reading practices are based on the utility reading roughly one-twentieth of their meters on each of the 20 working days in the month. Consequently, it is unlikely that bills from multiple locations will all arrive on the same day. Some utilities are addressing these markets with new, extra-cost products. There are also third-party billing firms that essentially take over the utility bill payment function for customers and, in turn, send the customer utility bills the way the customer wants them. For example they may consolidate into a single invoice, the bills for all utilities for all plants, including plants served by multiple utilities in different states.

4.2.5 Marketing

Utilities market electricity as a beneficial service (e.g., “live better electrically”), even in times of scarcity and high costs. When energy conservation is a lesser concern, they actively encourage new customers to locate in their service areas for economic development and to increase electric use to boost revenues. Many utilities have resource centers that are designed to showcase state-of-the-art electric technologies to encourage increased adoption of electric uses and therefore electric sales.

4.2.6 Energy Efficiency and other Demand Management Services

Regulated utilities are often a source of information and advice for retail consumers on energy efficiency, efficient equipment selection, and similar support, including audits, rebates, discounts, and financing. Generally, these services are provided at the direction of regulators, not as voluntary programs. As a result, they are often designed to accomplish objectives that benefit the utility as well as the customer. In fact, services that benefit only the customer, not the utility, may be restricted by regulation or require customer payment.

4.2.7 Renewable Energy Resource and R&D Programs

Utility ratepayer funds are also often used to develop renewable energy resources, such as wind and solar power and to fund research that benefits electric utilities, such as research into power plant maintenance, transmission design, and automated distribution system operations. Much utility research is conducted collaboratively, where many utilities contribute a fixed share of revenues to be used for research by third parties, such as the *Electric Power Research Institute (EPRI)*. Some of these programs result in pilot and demonstration projects, such as installation and operation of a wind turbine or fuel cell in the utility system.

4.2.8 Public Benefits Programs

Electricity has been deemed to be an essential public service. Everyone is expected to have access to power to meet minimal health and safety needs. Not all customers have the financial wherewithal to be able to pay for the electricity they use. As a result, most regulators require utilities to collect a small fee from customers to operate programs that reduce the financial burden on low-income and elderly customers, such as home weatherization and low-income customer rate subsidies.

4.2.9 Wholesale Customer Services

Most large utilities also have wholesale customers they serve with power and transmission services. Typically, these wholesale customers are other, smaller utilities that sell the power to retail customers. In rare cases, wholesale customers may be retail customers in all but name due to prior regulatory agreements. Naturally, the level of service provided to these customers varies considerably from those for retail customers. Although wholesale customers can obtain power and transmission services from multiple suppliers in the competitive market, most utilities also offer bundled service under a regulated tariff. This tariff typically consists of the following:

- Generation at prices agreed to between the customer and the PUC. These may be cost-based, using the utility's generation as a basis, or they may be market based.
- Selected ancillary services, especially load following and load shaping services that match power demands in real-time. Most wholesale energy purchases are for power in blocks, such as 50 MW for 24 hours for 2 months. These are often take-or-pay deals where power that is not used is essentially forfeited to the supplier, but paid for nevertheless. Load following and shaping services exactly match variations in power use to generation. These services can be purchased in the wholesale market for a customer's entire load or only a residual that remains after a block purchase. Typically, load following services are quite expensive.
- Transmission and associated ancillary services are usually bundled into the transmission tariff. Generally, the State-regulated tariff for these services is higher than the FERC rates.

Additional services may also be available outside the standard tariff, such as substation services (transformation), multiple delivery points (service from more than one substation with additional meters for each), and maintenance of transmission facilities.

A Historical Sidenote -

The New York Blackout of 1965 and the Creation of NERC



The first major U.S. power blackout occurred in New York State in 1965. Industry response to this event radically changed the way utilities manage transmission and generation and laid the foundation for the equally radical changes to power markets and transmission management that began in the 1990s. The foundation for the New York blackout was built gradually over years of increased utility reliance on power imports from more and more remote locations, primarily in Canada. New York utilities had also begun to rely on generating reserves from adjacent utilities in case of emergencies. A power surge on the Canadian power lines caused protective circuit breakers to trip. The loss of power imports from Canada shifted demand to weaker lines from adjacent utilities. These lines also tripped due to the sudden increases in demand. These failures had a ripple effect that ultimately resulted in failures throughout the region and a day-long blackout.

The New York blackout of 1965 was a wake-up call to the power industry. The industry responded to the blackout by creating a voluntary, utility-managed reliability organization, the North American Electric Reliability Council (NERC).

NERC divided the nation into ten reliability regions, with each region covering multiple states (except for the Texas-specific Electric Reliability Council of Texas, ERCOT) (Figure 4.4). The largest council is the Western Systems Coordinating Council (WSCC), which covers the entire Western Interconnection, including 11 western states, two Canadian provinces, and the northern portion of Baja California in Mexico. The smallest is the Mid-Atlantic Coordinating Council (MAAC) covering New Jersey, the District of Columbia, and most of Pennsylvania and Maryland. Each reliability council promulgates system planning and operating criteria that are intended to ensure that each utility with generation or transmission assets builds and operates them in a way that allows system controllers to preserve bulk power reliability.

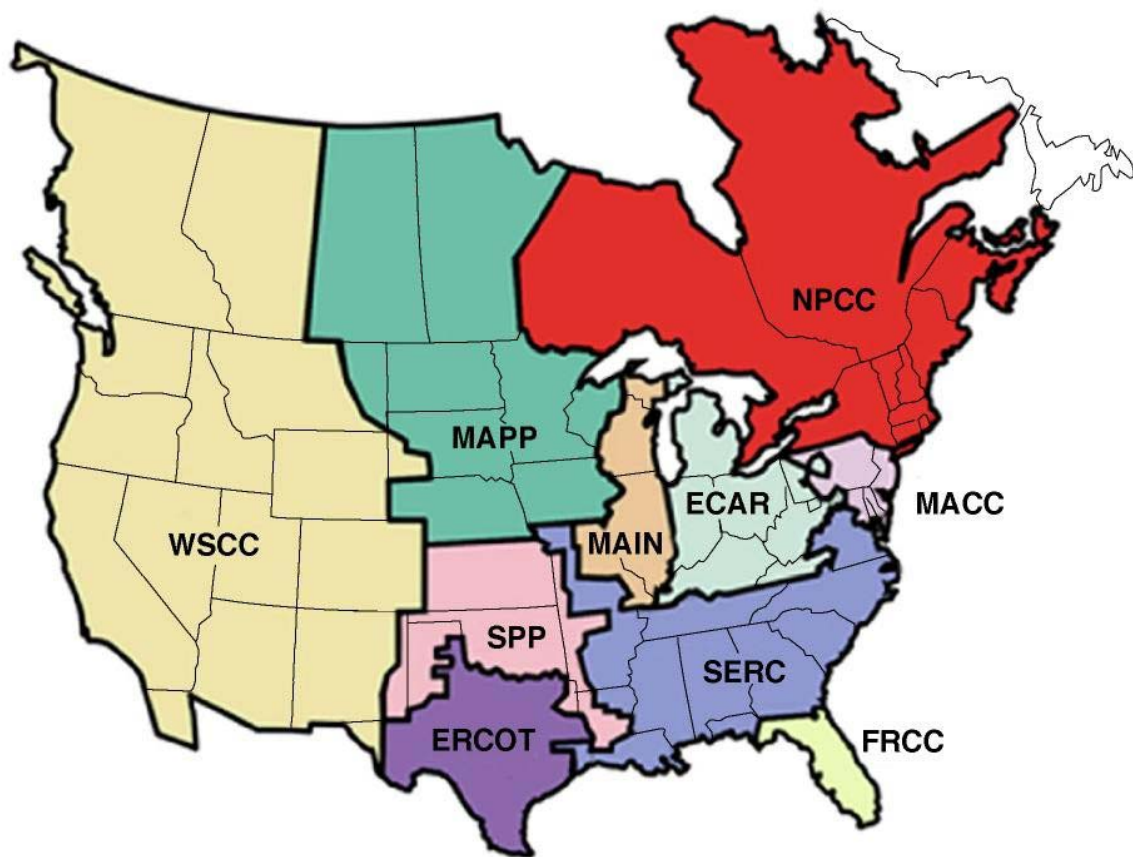


Figure 4.4. The 10 reliability regions of the North American Electric Reliability Council

5.0 Utility Operation Under Regulation

5.1 Why Regulation?

In normal competitive markets, prices are set through the interactions of buyers and sellers in fair markets. Ideally, consumers set the value of products by establishing the price at which producers and consumers are both satisfied. Competing firms have different costs and offering prices. If competition is fierce, firms may sell products for less than the cost of production. If supply is tight and demand high, prices may be multiples of production costs. Regardless, the final price is supposed to reflect market value, called *value of service* pricing. Regulation of utilities is based on the inherent risk that a single monopoly supplier will overcharge consumers due to the lack of competition and high demand. Benchmark prices from competitive firms are not readily available in regulated markets, so regulators set prices based solely on production costs, called *cost of service* pricing. In the United States, state PUCs regulate retail electricity prices while FERC regulates wholesale prices.

The historic standard for wholesale power exchanges has been that the price of electricity be cost-based, not market-based (“what the market will bear”) and that savings associated with the exchange be “shared.” In other words, the extra income the seller reaps and the reduced costs the buyer receives are shared between the two utilities and passed on to consumers in lower rates. The cost-based regulatory approach was adopted by FERC to stimulate so-called economy exchanges and to protect buyers (small utilities) from the inherent advantage the sellers (large neighboring utilities) had in the transaction.

The seller’s advantage was not only in having lower costs, but also in controlling the transmission lines between the buyer and the seller. If the buyer wanted to buy lower cost power from another utility, it would have to wheel the power over transmission lines owned by its large neighbor. If the transmission owner refused to allow the transfer, the utility would be forced to buy higher priced power from its neighbor. This is one example of *market power*. Although market power was identified as an issue early on in the industry, it has become a critical issue in the debate on whether, and how, electric markets should be restructured.

5.2 Power Pools and Regional Power Markets

In addition to providing reliability reserves, adjacent utilities can also provide alternative sources of generation to meet routine loads and partners to jointly build new generation. Through these arrangements, utilities can collaborate to operate their collective portfolio of generation so that operating costs are minimized. For example, if a utility has generating resources that cost 3 cents/kWh to operate and its neighbor has resources that produce power for 1 cent/kWh, it would be advantageous for the first utility to buy power from its neighbor rather than operate its own plants. Implementing this scheme creates two challenges. The first is how to price the power in the exchange. The second is how to create and manage an exchange, or market, that ensures cost minimization while maintaining overall system reliability. (Remember, how generators are used affects transmission operations and reliability.)

Pricing of power exchanges is an issue because the wholesale transactions involved are regulated, so the seller is not supposed to earn “extra” profits for the sale and the consumers need to both be protected from

unfair prices and benefit from the exchange through reduced rates. In the example, the seller would charge 2 cents for the power it generated for 1 cent. The buyer would realize a 1-cent savings over its 3-cent generating cost. The profit to the buyer and the savings to the seller would both be passed on to consumers in lower rates. Each transaction is subject to review by FERC (for price and term) and state PUCs (for application of profits and savings to rates).

In order to facilitate economy exchanges and collaborative generation development, utilities formed *power pools*. Pools have standard procedures for conducting power exchanges among members including arranging for wheeling. As a result, each transaction does not have to be submitted for FERC review. Pools usually have routine mechanisms for negotiating exchanges, such as a set time each day for buyers and sellers to join a conference call to conduct trades.

There are two types of power pools - tight and loose. A loose power pool is a voluntary association of utilities that negotiates generation sales primarily on a bi-lateral (two-party) basis. Bi-lateral transactions are private, thus other participants are unaware of the terms of the exchange, including price and transmission access. In contrast, tight power pools require true pooling of generating and transmission assets. The cost of each resource in the pool is known and each is operated on the basis of those costs, with the lowest cost resources being used more than higher cost ones. Operation of pooled generation also requires cooperative operation of transmission in the pool. As a result, tight power pools have some form of centralized transmission dispatch. Usually, there is a control center for the pool as a whole that issues dispatch instructions to the control centers of the larger utilities in the pool. Examples of tight pools include the New England Power Pool (NE Pool), the New York Power Pool (NY Pool), and the Pennsylvania, [New] Jersey, and Maryland Pool (PJM). PJM is the oldest U.S. power pool having been founded in the 1920s.

5.3 Utility Rates and Costs

Regulation of utility rates is based on regulation of utility costs. A utility's costs are composed of two primary components -- capital investments and operating expenses. Capital investments include generating plants, transmission and distribution systems, and other infrastructure such as office buildings. Utilities raise capital for investments by borrowing from lenders and issuing stock to investors.

5.3.1 Rate of Return

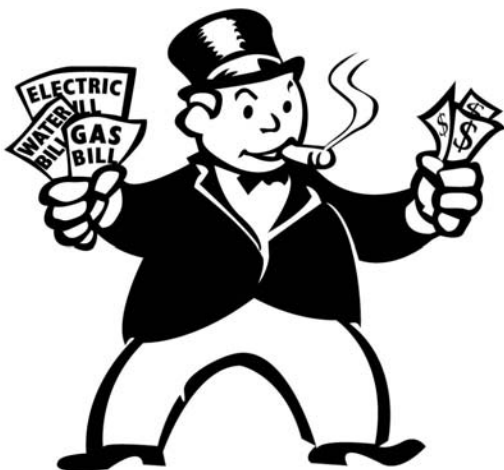
Regulators allow utilities to earn a *rate of return* on invested capital raised from investors, a sum that is called the *rate base*. Regulators set the rate of return in a range that allows a utility to earn a profit on its investment and attract capital at favorable rates (compared to bank borrowing). Payment of the rate of return allows a utility (and its investors) to recover its investment through rates. Thus, the rate of return allows a utility to recover a return **on** its investments (like interest on a loan) and a return **of** its investments (like repayment of loan principal). Operating expenses for a utility consist primarily of generating-plant fuel costs, purchased power and transmission services, and labor. Fuel costs vary depending on how much power is produced. Labor costs vary somewhat with power production and other utility operations, but are mostly fixed costs, in the short run.

A Historical Sidenote -

The Beginning of Utility Regulation – PUHCA

Initially utilities were not regulated. Early utilities would often compete for the same customers including building duplicate distribution systems. Naturally, competition was greatest in urban areas and within these, in wealthier neighborhoods, because it was cheaper to compete in densely populated areas and wealthy customers were more likely to use more power.

Over time, unchecked competition began to take its toll, not just on consumers, but also on utility companies. At first, municipalities stepped in, regulating the number of utilities, requiring *universal service* (to poor as well as rich customers), and restricting each utility to service in specific areas of town to avoid the construction of duplicate systems. Different regulations and regulatory processes for each city and town created a difficult operating environment for utilities. Eventually both utilities and the public recognized that regulation of service territories and rates at the state level was preferable to continued customer competition, duplication of service, and different regulations in myriad municipalities. In the 1920s, utility regulation as we know it was established, characterized by a strong role for state public utility commissions.



During the 1920s, utility mergers resulted in utility holding companies that owned or controlled power, gas, water, and other utilities in many states. Holding companies own local utilities that may be regulated at the state level; however, the holding company itself cannot be regulated at the state level if it is engaged in interstate commerce. Holding companies often provide services to local operating utilities, such as power supply and transmission that are interstate in nature. Since state regulation was not sufficient to control the action of interstate holding companies headquartered out-of-state, Congress passed the Public Utility Holding Company Act of 1935 (PUHCA).

The PUHCA restricted the influence of holding companies, provided for regulation of holding companies at the federal level, limited the number and kind of utilities a holding company can own, and gave state regulatory commissions more control over affiliate utilities' rates and services. The combination of rational regulation and progress in technology allowed electric utilities to reduce electric rates. Electricity cost \$.30 to \$.50 per kilowatt-hour in the early 1920s (in today's dollars). The national average today is approximately \$.07 per kilowatt-hour.]

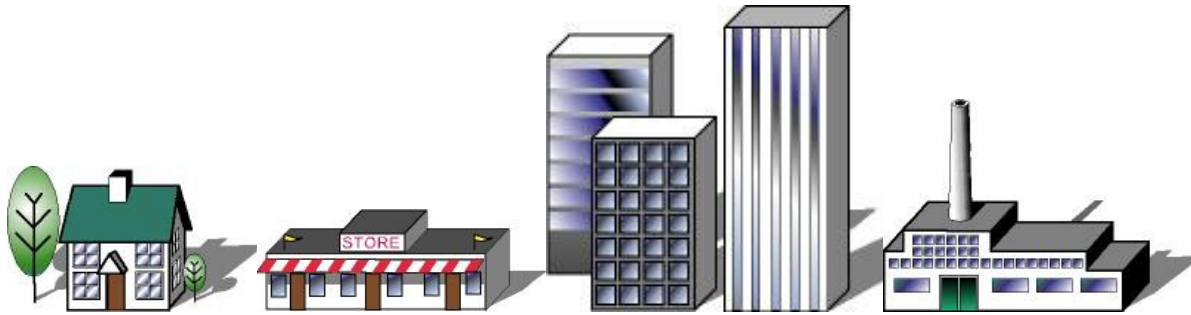


Figure 5.1. In a regulated utility environment, rates are designed to recover costs used to serve customers and customers are allocated to classes that each have different rates. Typical customer classes include residential, small and large commercial, and industrial.

The combination of debt service and operating expenses is the amount needed by the utility to operate effectively, its *revenue requirement*. Revenues from rates need to equal that amount. This, plus the allowed rate of return, sets the “rate level.” The process of *ratemaking* involves translating the rate level into specific rates for each customer, a process called *rate design*. The rate-making ideal is for the cost of service to be perfectly allocated to each customer; that philosophy is one of “cost follows cause.” However, customizing rates for each individual customer is far too expensive and cumbersome. Instead, rate design approximates customer-specific costs by grouping customers into similar *customer classes*. Rates are then designed to recover costs from a representative customer for each class (Figure 5.1).

Typical rate classes include residential, small commercial, large commercial, industrial, and street lighting. Customers are allocated into classes to ensure each class pays for an equitable share of utility costs. As a result, the use of utility infrastructure has to be allocated to each customer class. For example, residential customers require more infrastructure to serve because they use power at a lower voltage (which requires more substations, distribution wires, and transformers). Large industrial customers can use power at high voltage levels and are often served directly off the transmission grid. In other words, they may not require any distribution infrastructure – and may not pay for any share of those services.

5.3.2 Fixed Costs

Rates are also designed to recover fixed and variable costs equitably from each customer class. Fixed costs are assigned in rates through three mechanisms: 1) a customer charge, 2) a usage or kilowatt-hour charge, and 3) a demand charge.

5.3.2.1 Customer Charge

The first component, the *customer charge*, is designed to cover customer service costs, including metering, billing, and providing marketing and customer service facilities. The customer charge varies for each customer class and is generally a flat monthly fee regardless of consumption.

5.3.2.2 Kilowatt-Hour Charge

Recovering energy costs from customers is the second component of rates and the largest part of all power bills. Energy costs are recovered through a usage or *kilowatt-hour charge*. The simple form of a kWh charge is a fee that is the same regardless of time or quantity of use. Many small utilities use this kind of rate design, referred to as a *flat rate*, because it is easy to administer using simple kWh meters. However, most large utilities employ more sophisticated cost recovery mechanisms or rate designs. One common mechanism is for the cost per kWh to either decrease or increase as total use increases, which can be done through rate structures known as declining block or inverted rates (Figure 5.2).

A *declining block rate* provides consumers with an incentive to consume more power by reducing the cost per kWh as total use increases. Declining block rates were common prior to the oil crisis because power production costs actually decreased as more and larger power plants were built to meet growing demand. During the oil crisis, declining block rates were gradually eliminated in part due to Congressional guidance to state regulators, as a means to encourage energy conservation. After the oil crisis, when many utilities were left with surplus generating capacity, declining rates reappeared in some locations to stimulate demand so as to absorb some of the surplus, but idle, generation.

Inverted rates are the converse of declining block rates designed to discourage increased power use. Both declining block and inverted rates can have multiple blocks. The simplest form consists of two blocks. However, three or four blocks, each with a different kWh charge, are not unusual. Obviously, this kind of rate design requires regulation, as the utility earns extra profits as a customer consumes more power. Such a design would be impossible to implement in an open and competitive market where consumers tend to choose suppliers based on price.

Power production costs vary by time of day and season due to the differences inherent in the power plants that are on line during each period. Some utility rates also reflect these costs in *time-of-use* or *real-time* rate designs. Time-of-use (TOU) rates are similar to inverted and declining block rates in that the kilowatt-hour use charge varies in blocks differentiated by the time of use or season and often both. A simple TOU design may have a rate that changes on a seasonal, or monthly basis, with a higher kilowatt-hour charge in months with high demand (Figure 5.3). This kind of TOU rate does not require the utility to invest in more complex and expensive TOU meters.

More complex TOU designs have charges that vary over the course of the day. For example rates may be significantly higher between noon and 6 p.m., not as high between 6 p.m. and 10 p.m. and moderate the rest of the day. TOU rates that vary during the course of a day require a more complicated TOU meter. The most sophisticated form of TOU rate is real-time metering where the kWh charge varies each hour based on real-time production costs or market-based power rates. This requires a very sophisticated meter, often one that is tied in to a two-way communication system that allows the utility to read usage in real time. Some utilities provide customers with a forecast of prices ahead of time so they can adjust usage. Energy charges in deregulated markets will be based on prices set in real-time markets. This may not require customers to switch to real-time rates and associated meters, although most customers who do so will be in a better position to take advantage of competitive power markets. The typical installed cost of a real-time meter is about \$1,000.

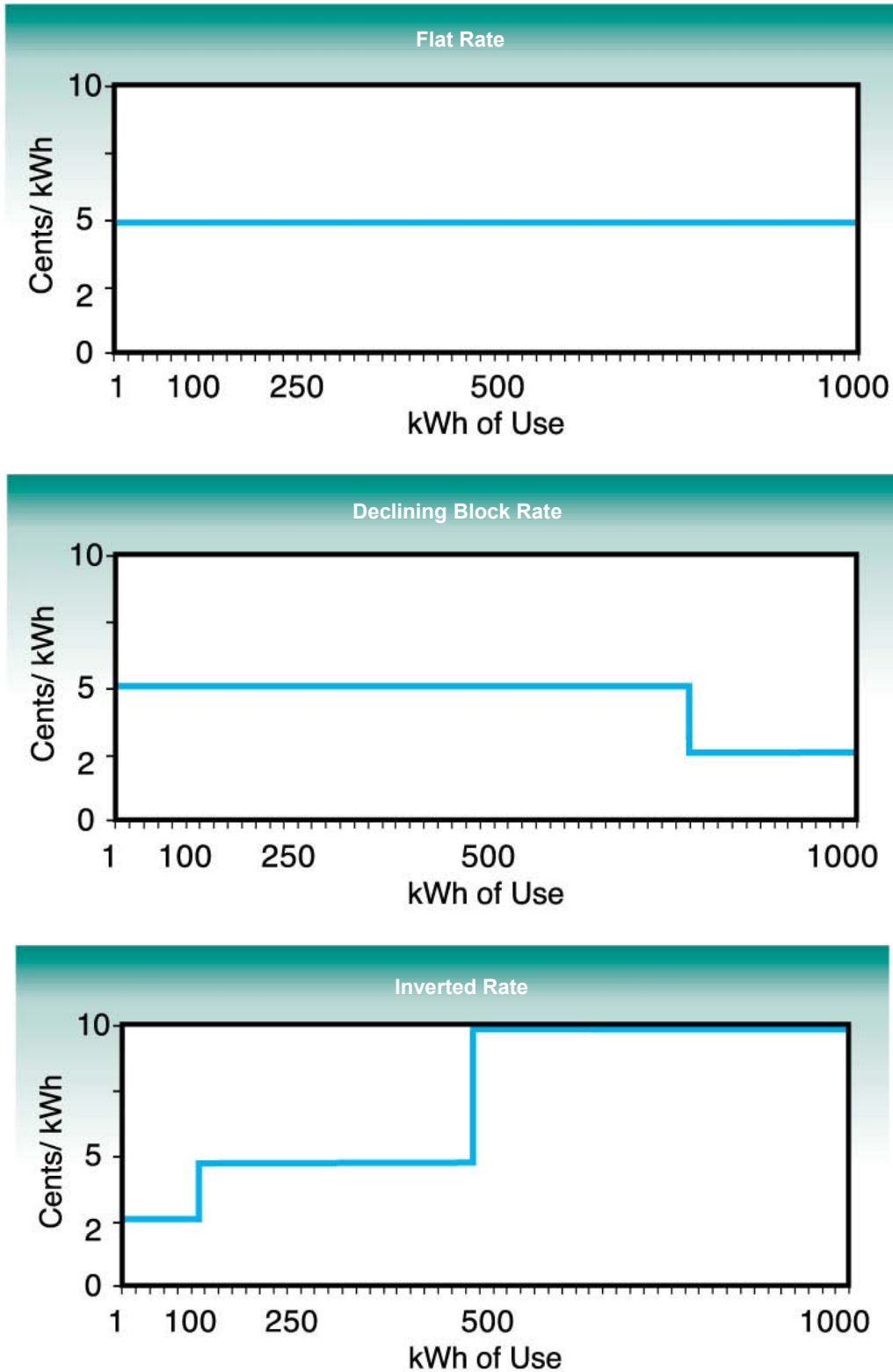


Figure 5.2. Flat, declining block and inverted rates are three rate designs employed by utilities. The flat rate is a kWh charge that remains the same regardless of time or quantity of use. The declining block rate encourages consumption by reducing the cost per kWh as use increases. Inverted rates discourage use by increasing cost per kWh as use increases.

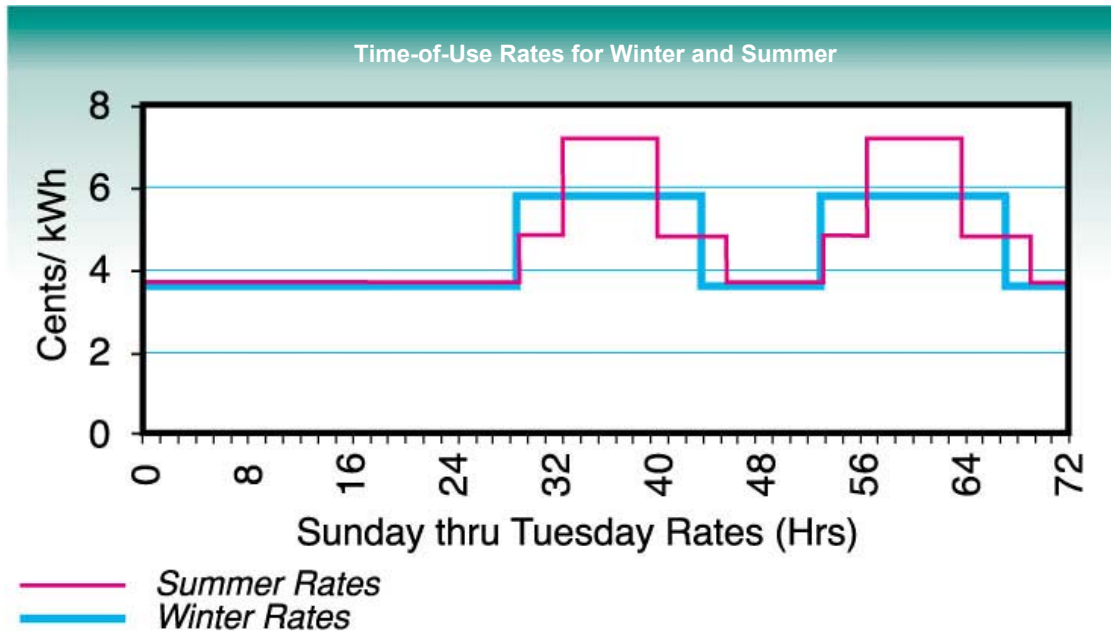


Figure 5.3. This is an example of a simple time-of-use rate design that varies by season, with higher charges during peak demand times in summer months.

5.3.2.3 Demand Charges

The third component of utility rate designs is a mechanism used to reflect the amount of generating capacity that is needed to serve the customer. Because power plant capital costs are fixed, like a home mortgage, how the plants operate is key to power costs. If the plants operate all day, every day (24 x 7 in industry jargon), a small daily charge can be collected to pay the “mortgage.” Conceptually, if the plant only operates one month out of the year, the charge may need to be 12 times larger. Rates for most non-residential customers are designed to capture this effect by measuring the maximum amount of demand used by the customer during the billing month. Typically, this peak demand is measured in kilowatts (corresponding to power plant capacity in megawatts) over a one-hour or shorter interval.

Peak power use is monitored with a *demand meter*, a kilowatt-hour meter with a separate *demand register*. Peak demand, as registered by the demand meter, is billed as a separate line item on the power bill. Demand meters are more complex and expensive than kilowatt-hour meters. Demand metering functions are built into TOU and real-time meters. In fact, TOU and real-time meters are often installed primarily for demand, rather than kilowatt-hour, metering. Demand charges may also vary on a TOU or real-time basis.

Demand charges are used by utilities to recover the costs of power delivery as well as generation. Power delivery systems - transmission and distribution networks - are designed to meet maximum demand. Because the cost associated with maintaining these networks does not vary with the amount of power used, it is appropriate to recover the cost of these systems through a peak demand charge. After deregulation, peak demand charges for **generation** demand are often eliminated in favor of real-time prices from a competitive power exchange. However, charges for electricity **delivery** will not be deregulated. As a result, a demand charge for use of the delivery network will remain. This charge will be significantly

lower than the demand charge for generation capacity. Most utilities may choose to levy this fee only during peak demand periods. For all other hours and seasons, there may be no fee for delivery.

Customers with similar electricity usage can have significantly different electricity bills based on demand charges. If a greater proportion of electricity is used during peak demand periods, both demand charges and any TOU rate impacts will be greater than for customers with usage that is more constant over the course of the day. A common metric for evaluating this impact is the *load factor*. Load factor is the ratio of **peak** demand to **average** energy use. It is calculated as follows:

Load factor for one month = [total **kWh** use for the month / number of hours in the month:
~720 hours] / maximum **kW** demand for billing interval, such as hour or 15 minutes.

Typical homes have a load factor of .45, businesses about .6, and industries between .85 and .95. A load factor of 1 means electricity use is constant throughout the day, week, and month. In general, the higher the load factor, the lower the average cost of power per kilowatt-hour when all charges are factored in. In other words, average kWh cost (the total bill divided by total use in kWh) is lower for customers with higher load factors. The lowest average kWh cost (and total electricity bill) is obtained when the load factor exceeds 1, as that indicates a shift in consumption to lower cost, off-peak periods.

5.4 The Setting for Rate Setting

Utility rates are established (set) through a process called a *rate case*. Rate cases are usually complex and lengthy undertakings. Because rates are regulated based on cost of service, rate cases primarily focus on a detailed examination of historic and/or projected utility costs. As a result, the utility has to open up its financial records for review by regulators and intervenors (such as residential consumer advocates, environmental organizations, large industrial customers, competitors such as vendors of other fuels and adjacent utilities, and other parties not associated with either the utility or regulator).

Rate cases are concerned with two primary issues, the *rate level*, or amount of money the utility is allowed to collect, and *rate design*, or how rates are structured to match the utility's revenue requirements. Utilities cannot change rate designs or levels outside of a rate case. Rate cases occur as a result of action taken either by the public utilities commission or by the utility. A utility generally initiates a rate case only when it needs to increase revenues or believes that it needs a higher rate of return to attract investment capital. Commissions will initiate a rate case if they believe that the utility's rates are in excess of their cost of service or cost of capital. Revenues may be adjusted up, or down, although the latter is much less common. Nevertheless, rate decreases also require a rate case.

A few states require utilities to submit to rate cases on a periodic basis, say every three years, and others can order rate reviews independent of the utility. In most states, intervenors may request a rate review, although the requesting party must agree to carry the burden of proof, and the decision to proceed is up to the regulator. In general, utilities and regulators try to limit the frequency of rate cases. As a result, utilities typically initiate rate cases only when they anticipate lower-than-expected revenues or rates of return, or when they have a significant change in capital investment, such as the addition of a new generating plant.

Because fuel costs are a significant component of utility rates, volatile fuel costs could, in theory, require frequent rate cases. To avoid that, many states have adopted *fuel cost adjustment clauses* that allow utilities to adjust rates periodically without a rate hearing. Fuel cost adjustments are evident in power bills because the fuel cost component of rates is identified as a separate line item on the bill. As more and more utilities rely on buying power from neighboring utilities, a purchased power adjustment mechanism is being used to track those costs as well.

Utility bills are also used to implement a number of social and utility system programs. Public benefits fees may be collected to pay for a wide range of activities not directly related to the provision of electricity, including covering unpaid bills for low-income customers, weatherizing homes of low-income and elderly customers and subsidizing their bills, research and development investments, investments in alternative energy resources, and investments in *demand side management* (DSM). Fees collected for these so-called public purposes are also included in utility rates.

Generally, *public purpose* or *public benefits* fees are collected in conjunction with the kilowatt-hour usage charge, as a percentage “rider” on the kilowatt-hour charge or as a flat fee. In other words, they are sort of like a sales tax. Often the collection of these fees is capped at a predetermined dollar amount per customer. For example, the fee may only be collected on the first 500 kWh used each month. Historically, utilities have collected and managed these fees. In the present deregulation environment the management of these funds is often being turned over to new institutions.

Some public benefits expenditures are not explicit in utility rates. One of the more common of these is the added costs associated with mandates for utilities to purchase power from renewable resources, often called *renewable portfolio standards* (RPS). Renewable portfolio standards may be embodied in legislation or in regulatory orders. The purpose of these mandates is to ensure a sustained, orderly development of renewable energy. Renewable portfolio standards also may be implemented through an actual purchase requirement (the utility has to buy power from renewable sources) or through a credit trading mechanism where the utility purchases a credit from a renewable developer rather than building the renewable generation on its own. The latter has the advantage of facilitating the development of renewable resources in regions with the best renewable resource potential, regardless of the location of the utility. In all cases, the RPS results in purchased power costs that are slightly higher than they otherwise would be, which is built into rates through the cost of power, typically in the kWh charge.

6.0 What is Deregulation?

6.1 Why Deregulation? A Historical Perspective

Historically, the cost of generating power declined as utilities built ever-larger power plants, which increased efficiency and reduced production costs. Utilities routinely requested rate reductions based on declining costs as well as to increase electrical demand. Increased electric demand required more and larger plants, which reduced costs further as well as increasing the utility rate base. This era was a win-win for everyone. Consumers had abundant, low-cost power; regulators oversaw declining rates, increased electrification, and economic growth; and utilities and stockholders gained financially.

The Arab Oil Embargo of the 1970s changed that in a hurry. Rapid increases in the cost of fuel to operate power plants translated into equally large jumps in retail power prices. Continued increases in oil prices and unstable fuel supplies led electric utilities to construct new power plants that relied on domestic coal and uranium. These plants cost much more to build than simple oil or natural gas-fired generators. Consequently, the fixed costs of utility operations increased, further increasing retail electricity prices. The natural consequence was consumer complaints and increased regulatory oversight.

For a variety of reasons, including a poor economy and customer resistance to higher rates, demand declined and many utilities ended up building more power plants than needed and/or plants that were very expensive. By the early 1980s, the situation appeared to be out of control, with most utilities requesting routine, often significant, rate increases and several utilities on the verge of bankruptcy. As a result, regulators began to take a much more active role in utility planning. One response was for regulators to require utilities to evaluate conservation and other alternatives rather than automatically building new plants. This process, called *integrated resource planning (IRP)*, was successful in keeping retail rates in check, although rates were still thought to be too high.

The 1970s and 1980s saw the launching of several trends that paved the way for electric utility deregulation. The first was the energy-efficiency efforts resulting from the oil price shocks. Rising fuel prices hit the transportation industry especially hard. In response, engine manufacturers designed more fuel-efficient motors. The jet turbine engine used by the airline industry is identical to that used in peaking power plants. Consequently, power plants based on these new, aero-derivative turbines had lower production costs than older designs, significantly so. Utility demand for natural gas as a generating fuel could not be satisfied at 1970 levels of production owing to peculiarities in natural gas industry regulation. Solving this problem led to the second trend, deregulation. Deregulation of the natural gas industry paved the way for electric industry deregulation both by unleashing market forces to free up natural gas for electricity generation and through FERC's experience with gas industry restructuring.

6.1.1 A Digression into Natural Gas Deregulation

The natural gas industry consists of exploration and production (E&P) companies and pipeline companies acting as somewhat separate industries. The Federal Power Act of 1935 created the Federal Power Commission (FPC) (Figure 6.1). The Natural Gas Act of 1938 directed the FPC to regulate natural gas pipelines, but not wellhead prices. Like all federal regulations, jurisdiction was limited to pipelines in

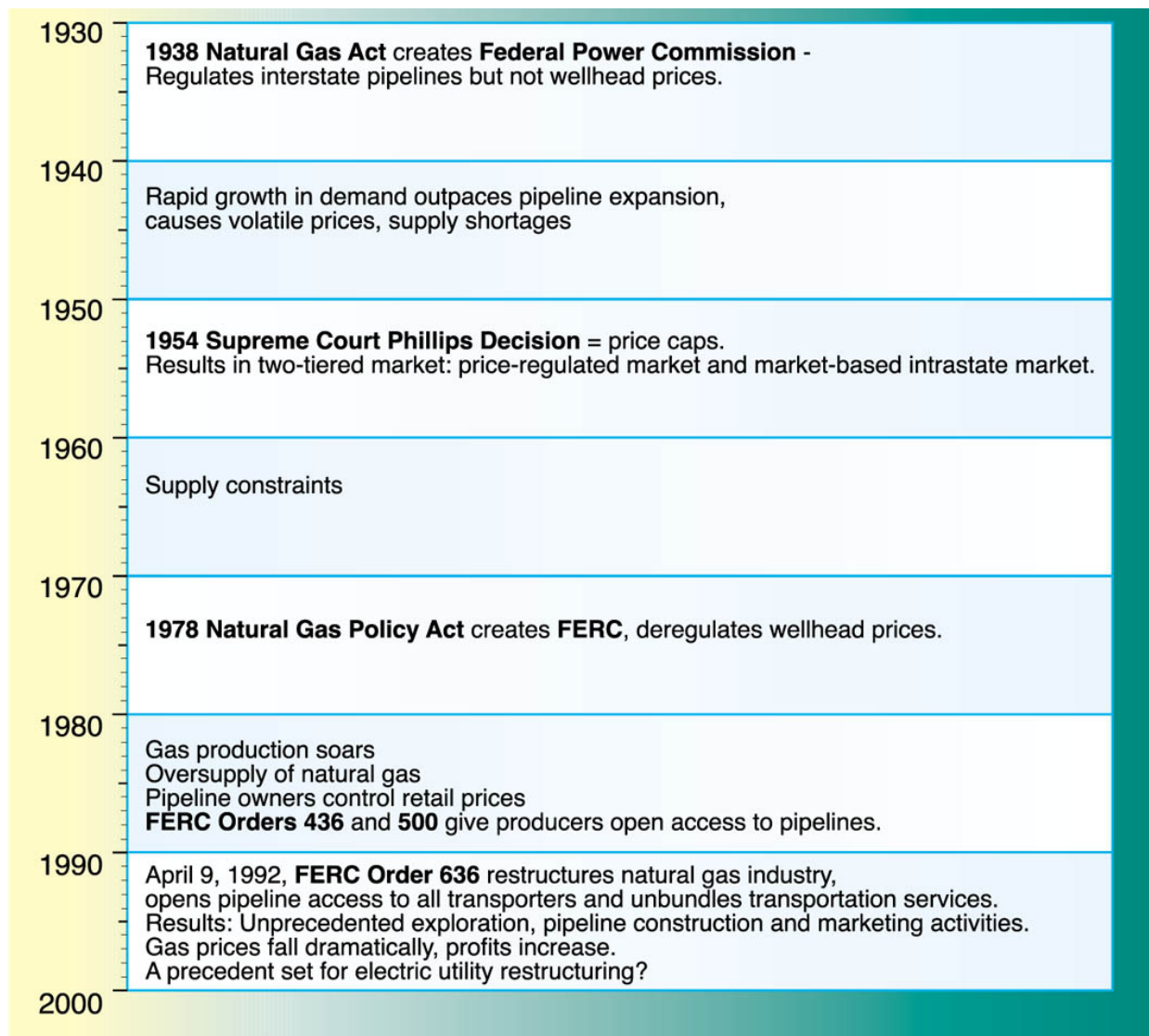


Figure 6.1. A Timeline of the U.S. Natural Gas Industry in the 20th Century

interstate commerce. Intrastate pipelines were beyond the reach of FPC price regulation. Demand for natural gas during the 1940s and 1950s exceeded the rate of pipeline expansion, resulting in price volatility and supply shortages in parts of the country. This led natural gas producers to request price caps on pipeline transportation for gas producers. The FPC did not believe that the Natural Gas Act gave it that authority.

In 1954, the Supreme Court determined that regulation of consumer prices required control over both producer prices and transportation in the landmark Phillips decision. Although price volatility was reduced by the Phillips decision, regulated price caps on production and pipelines eventually resulted in a two-tiered market; a price regulated interstate market and a largely market-based intrastate one. Producer states had ample gas supplies and transportation whereas user states had neither, resulting in the supply constraints of the 1970s. The solution came in the form of the Natural Gas Policy Act of 1978.

The Department of Energy Organization Act of 1977 created the Federal Energy Regulatory Commission (out of the old Federal Power Commission). The Natural Gas Policy Act of 1978 directed FERC to “reform” natural gas pricing. This essentially reversed the Phillips decision by deregulating wellhead gas prices. Gas production soared in the face of pent-up demand, depressing consumption. Consequently, the 1980s witnessed a significant oversupply of natural gas, a so-called bubble. Despite deregulation, competitive gas markets failed to develop, primarily due to continuing problems with pipeline regulation. At the time, pipeline companies controlled access to markets by both producers and consumers because pipeline companies purchased the gas they transported from producers and resold it to consumers.

Obviously, the price to consumers is dictated by the price paid to producers. Non-competitive selection of producers led to higher-than-necessary consumer prices. In addition, pipeline companies provide a variety of other services ancillary to gas transportation, including storage, balancing (evening out day-to-day demand variations to match monthly contract demand), and so on. Typically, pipeline companies bundled these services into the cost of transportation. In order to cut the Gordian knot presented by pipeline companies’ control over end-user prices, the FERC issued a series of orders aimed at introducing competition into the pipeline business while retaining regulatory control over the transportation function.

The first of these, Orders 436 and 500, were issued in the late 1980s. These orders allowed consumers to negotiate prices directly with producers and required pipelines to transport the gas resulting from these negotiations. These rules maintained the traditional role of pipeline owners as marketers (buyers and sellers) of natural gas, but allowed gas producers to secure access to pipelines for their own use. This allowed producers to balance supplies across production regions. In other words, if a producer had insufficient volume in one area but plentiful supplies in another it could arrange to transport the surplus to the region with excess demand. In these orders FERC established the concept of open access, or the use of a gas transportation system that one party owned by other parties on an equal access basis. Because pipelines would be transporting gas from unknown producers in unknown quantities, FERC established procedures for nominating sources of gas supply and allocating the gas being transported to specific shares of pipeline capacity. Differences between contract gas shipments and actual consumption left pipelines to make up the difference. Accordingly, FERC made balancing a competitive service. These orders stimulated innovation in pipeline tariffs to reflect variations in reliability (firmness) and transportation contract duration.

Reacting to industry innovation, FERC requested comments from consumers and industry about new ways of structuring gas transportation in what it called a Mega-Notice of Proposed Rulemaking, or Mega-NOPR, in July 1991. The Mega-NOPR marked the beginning of the end of gas price regulation. FERC Order 636, issued April 9, 1992, “restructured” (in FERC’s words) the natural gas industry to stimulate competition by consumers for gas supplies and transportation. Order 636 required pipeline companies to open access to capacity to any and all transporters and to unbundle transportation services so as to allow customers to select supply and transportation services from any competitor in whatever quantity and combination they desired. Order 636 had a revolutionary impact on the natural gas industry and wholesale gas market. It unleashed unprecedented exploration, pipeline construction, and marketing activities. Gas prices fell dramatically, while profits increased from increased sales. Electricity producers became a new market.

Financial markets quickly developed commodity products that paralleled the evolution of physical natural gas markets, including supply products tied to one or more of the 40 or so natural gas trading hubs that

allowed buyers and speculators to hedge price and transportation costs irrespective of their actual location. In other words, consumers could negotiate the best terms for supply and transportation to their site and simultaneously negotiate better terms in other markets as a price hedge. The natural gas commodity market is now the most active commodity market on the New York Mercantile Exchange.

Order 636 also established a precedent for FERC to follow in electricity markets and provided lessons that were invaluable as FERC turned its attention to the electricity market, which it did next.

6.1.2 Back to Electric Industry Restructuring

By the early 1990s it was becoming apparent that electric industry regulatory approaches were not working. IRP was successful in holding rate increases in check and stimulating consumer choice, but the process was highly adversarial, time consuming, and expensive. Regardless, rates were still high and significant differences among adjacent electric utilities and between gas and electric utilities caused political problems. Economic development efforts were stymied where electric rates were high, resulting in firms expanding in low-cost states. In 1994, California completed a review of the electric utility planning and regulatory processes in the state and concluded that reforms were needed. At that time, California had some of the highest electric rates in the nation and it was looking for ways to bolster its economy, which was hurt by military base closures, the restructuring of the aerospace industry, a lingering recession, and a generally high cost of conducting business.

One option considered was to deregulate the electricity supply portion of the retail rate and allow consumers to have direct access to wholesale suppliers. This would remove the financial risk of power plant development from consumer rates and place the risk in the context of a competitive market. Although industry deregulation was the most radical option identified, industry quickly aligned behind it. The rest, as they say, is history -- deregulation of the domestic electric utility industry, meaning the substitution of market prices for government regulation of the energy portion of utility rates, was launched.

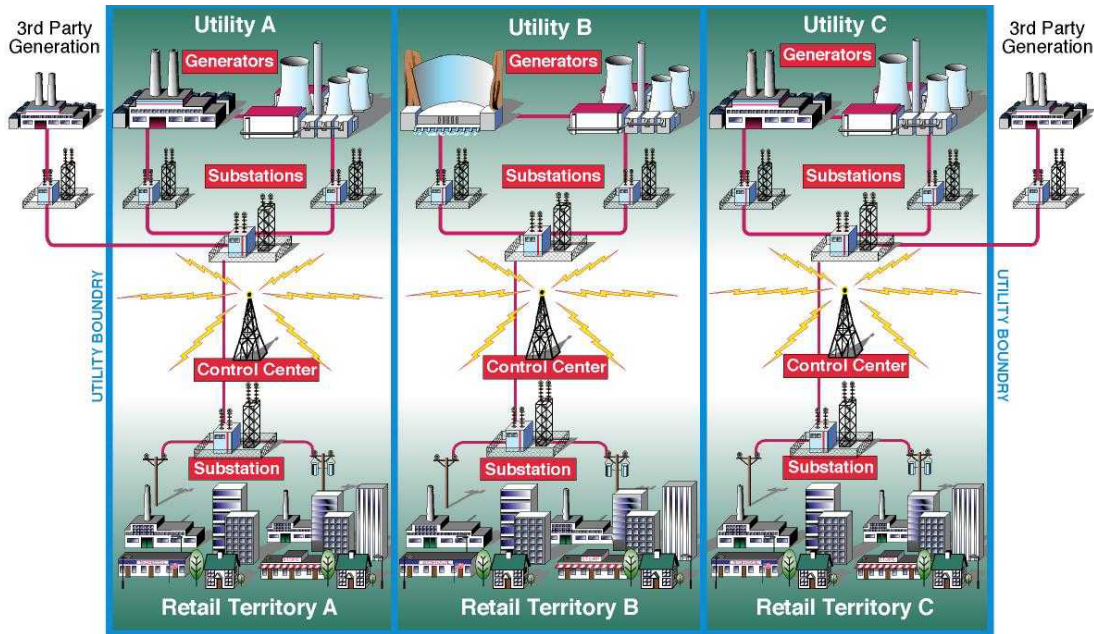
6.1.2.1 California Follows Great Britain Model, Sort of

Deregulation in California followed several years of so-called deregulation in Great Britain and other countries. However, deregulation in Great Britain and elsewhere was initiated by privatizing state-owned utilities rather than introducing market forces to privately owned utilities, as in California. British deregulation was implemented through the introduction of new institutions designed to emulate competitive markets, including a power pool. In addition, the British privatized utilities horizontally, into separate generating, transmission, and retail companies. California borrowed some of the British reforms to launch deregulation in the United States.

6.1.2.2 Recap of Regulated Model

Industry restructuring is best understood in contrast to the regulatory model presented earlier (Figure 6.2).

Structure of the Traditional Utility



Structure of the Deregulated Electric Supply System

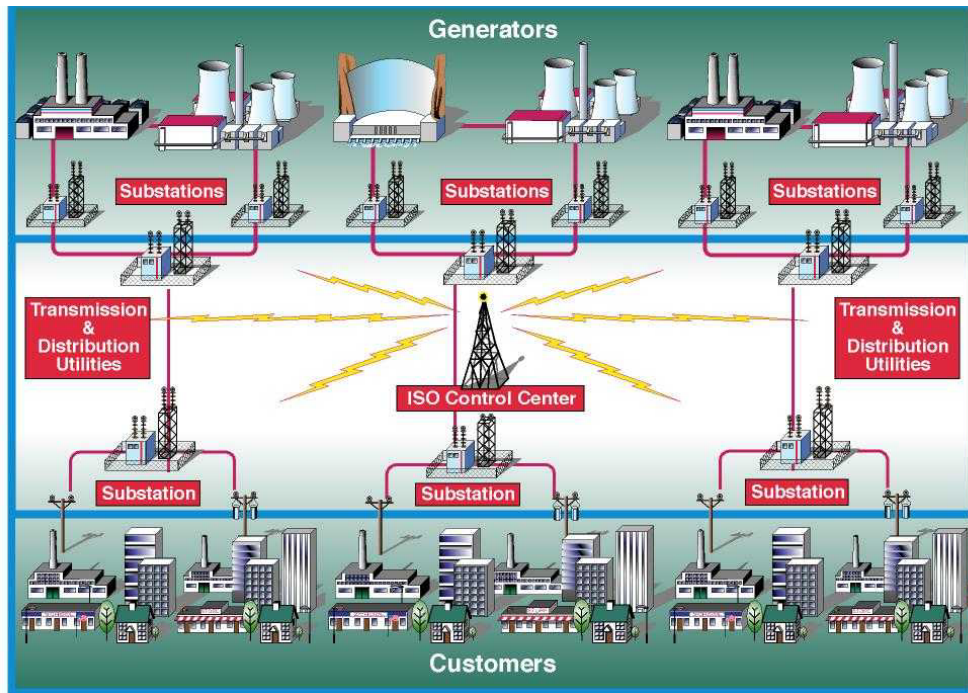


Figure 6.2. A Comparison of the structures of traditional and deregulated electric supply systems. In the traditional system, although the utility may purchase power from neighboring utilities, it is primarily responsible for its own generation, transmission, and distribution of power to all of the retail customers in its service territory. If it is large enough it will have its own control center. In the deregulated supply system, generation and distribution are unbundled and customers are no longer captive but are free to purchase from any suppliers on the grid. Purchasing of power is done via market mechanisms like the power exchange and transmission scheduling is conducted by the Independent System Operator (ISO).

Key features of the regulated utility model include the following:

- Regulated utilities own most of the generation needed to meet the needs of customers in a dedicated service territory.
- The local utility may import power to meet demand some months and export surplus power to adjacent utilities during others.
- Neighboring utilities may use the local utility's transmission lines to wheel power through to other utilities. FERC regulates the use of transmission lines, including rates, for wholesale transactions, although each state continues to set rates for the portion of transmission lines not used in wholesale trade.
- If the local utility is a major utility (a utility with its own generation and transmission) it manages its own generation and transmission using a control center that dispatches both. The control center may provide a similar service for smaller, adjacent utilities.
- Regulated utilities have an "obligation to serve" all customers with all the power they require, including adequate generation, purchased power, and transmission, including spare capacity to ensure they can meet peak demand and maintain reliability.
- Inter-utility sales of this surplus power may, nevertheless, result in an active and competitive wholesale power market, although FERC regulates prices in the wholesale power market.

The course of utility deregulation impacts all of these processes. Industry restructuring is replacing vertically integrated utilities and utility-managed institutions with specialized firms and new institutions managed by all market participants.

6.2 Utility Functions after Industry Restructuring

As noted previously, conventional utility operations, prior to industry restructuring, consisted of generation, transmission, distribution, and service to captive customers. If deregulation is rather narrowly defined as the substitution of market forces for regulated generation rates, it does not seem particularly revolutionary. In order to create an appropriate environment for consumers to participate in the generation marketplace, new rules and standards of conduct are needed to ensure truly competitive markets result. This process has launched a series of changes in utility management and institutions that, cumulatively, are revolutionary. A description of each follows.

6.2.1 Power Exchanges, Pools, and Wholesale Markets

In a deregulated environment, the power pools that had existed in many regions are replaced by power exchanges (sometimes still called pools) for the wholesale marketing of power **only**. Tight power pools integrated the operation of wholesale markets and transmission operations. They also excluded non-utility participants. Accordingly, new power markets require new rules and new methods for conducting transactions. Specifically, power trading has to be isolated from transmission operations to prevent collusion between the two or insider trading based on non-public information about plant or transmission line outages.

Implementation of price deregulation requires open markets and *transparent pricing*. Transparent prices are prices that can be readily determined by market participants. If two parties enter into a private buy-

sell agreement, no one else knows the agreed-upon price. Buyers and sellers set transparent prices in an open environment where other interested parties can monitor the prices offered. Exchange markets typically take the form of *bid-offer* auctions where sellers can bid against each other and market clearing prices are known by all parties, including consumers, buyers, and sellers.

The auction can have a single buyer that clears all bids or it can have multiple buyers. A single-buyer market operates like the auctions familiar to most of us, including on-line auctions. Multiple bids are received and the sole “winner” is the highest bidder as determined by the seller or its agent. Multi-buyer auctions are characterized by *bid-ask negotiations*, which may occur among the multiple buyers and sellers simultaneously. The stock and commodity exchanges are good examples. In general, sellers have an “ask” price and buyers a “bid” price. The difference between the two is called the *spread*. The size of the spread can be used as an indication of market liquidity, or the number of both willing buyers and sellers. The greater the number and volume of transactions, the more liquid the market and, generally, the smaller the spread. Both single and multiple buyer/seller auctions are employed in wholesale power markets.

It isn't enough to simply create a market or to declare that an existing power pool is now competitive. Market entry rules need to be developed to ensure open access for all qualified traders. Also rules and standards of conduct need to be adopted that invite competition. Typically, these deal with two major concerns of traders, *market power* and *market manipulation*.

6.2.1.1 Market Power

Going into a deregulated power market the local utility has inherent advantages. First, it owns sufficient generation to satisfy the needs of the local market. It had to as part its obligation to serve retail customers. Second, utility owned generators are part of the company that owns and operates the transmission system which all traders must use to access the market. Finally, it has brand awareness in the retail market. In order to make other sellers comfortable that the incumbent utility does not have market power, or undue market influence, deregulation rules require local utilities to mitigate potential market power.

Market power can be managed through a variety of mechanisms and one or more of these have been adopted as various states have deregulated. First, the market can be enlarged so that the power of any one incumbent provider is diluted. Since deregulation occurs at the state level, the market automatically expands to the entire state, not just one utility service area. In other words, all of the utilities in the state can now compete for sales to all customers in the state. That is rarely sufficient to prevent market abuse as most states have one or two large utilities that generate most of the power. A second technique is to require the utility to divest itself of some, or all, of its generation or to restrict sales into the local market.

Divestiture provides an easy way to increase competition in a state. First, it reduces the amount of generation the incumbent utilities have to sell. Second, it invites new competitors into the state through the sale of the power plants. Consequently, this is a fairly common solution. A third option, adopted by California, is to require utility power sales through a third-party power exchange. This prevents the utility from making sweetheart deals with favored retail customers in bi-lateral contracts and from withholding capacity from the market to manipulate prices. California adopted this approach as an interim measure until the state's utilities were able to divest themselves of at least half of their generation.

When deregulation was launched in California, the long-term future of the California Power Exchange (PX) was expected to depend on its perceived value to energy market participants. In other words, the PX was required to operate during the transition period to fully competitive markets. After that, the utilities would be free to buy and sell power bi-laterally or through other exchanges. The future success of the PX would rest on the PX itself providing a service market participants valued. We now know, of course, that the PX went bankrupt first (but more about that in later sections).

6.2.1.2 Market Manipulation

Market manipulation is difficult to detect and manage. Prices in electricity markets can be manipulated through a variety of mechanisms, including restricting power generation, restricting transmission access, and manipulating power exchanges. Restricting power supplies has the effect of increasing prices in the short run, because prices are a function of supply and demand. Generation can be restricted several ways. First, the utility that owns and controls transmission lines into a market can limit access to those lines. Second, generation owners can simply limit bids into the market. This requires collusion among all generators to be effective, unless some of the generators still have market power. Finally, a generator can declare that one or more power plants are out-of-service, thereby withholding capacity from the market. Regulators and power exchanges have anticipated these forms of market manipulation and adopted rules and procedures to manage them. (Alas, when these words were initially written we had faith that they were true. As we now know from the California crisis, generation withholding is difficult to police and thwart and it is a highly successful strategy for manipulating prices. Depending on the market design, it doesn't require much collusion to implement.)

Utility use of transmission capacity to manipulate the market by favoring its own generation or limited access by competitors has been addressed by FERC. In FERC Orders 888 and 889, transmission-owning utilities are required to isolate the power trading and transmission operations from each other. In addition, all requests for transmission access, including the utility's own use, are required to be posted to a public bulletin board and satisfied on a first-come basis. FERC has gradually asserted its authority in this area and is compelling utilities to turn over the transmission scheduling function to a third party, variously called a Tariff Administrator or Independent System Operator (ISO) or Regional Transmission Operator (RTO), more about these in a later section. For short hand, we will use the ISO abbreviation.

Power exchanges and ISOs/RTOs are FERC-regulated because they engage in interstate commerce. Each exchange has its own rules and procedures, which have to conform to FERC directives. One of these is a requirement for a market monitoring or market surveillance function. Market monitors review power trades, after the fact, to determine if one or more participants are attempting to manipulate the market. If problems are identified, market reforms are recommended. If fraud is discovered, evidence is provided to the appropriate authorities for prosecution. All of the major power exchanges have witnessed trading activities that affect market prices and which were not anticipated by market rules at the time. In response new rules are continually recommended and adopted. Exploiting loopholes to make money is not illegal. Cases of apparent illegal attempts at market manipulation have been documented and are being prosecuted.

Unfortunately, continued market abuse is creating a sense that deregulated markets are inherently flawed and that a return to regulation may be preferred. This is unfortunate, as wholesale power and natural gas

markets are generally working fine most of the time. Most importantly, competitive markets have relieved FERC of having to review a growing number of market-based wholesale power trades. That is allowing the industry to mature and adapt much faster than it otherwise would. In turn, it is allowing FERC to turn its attention to ways to better monitor emerging markets and discipline illegal and unethical behavior. These reforms are just starting, pushed on by the California crisis, but progress is being made at a very rapid rate for this industry.

6.2.2 Plant Selection and Dispatch in a Power Exchange

Power exchanges modify the way generating plants are scheduled and dispatched. Historically, the local utility dispatched power plants based on utility **operating** costs, without comparison to alternative, non-utility-owned plant costs. In contrast, power exchanges use **bid prices** to establish the plant dispatch order. Most exchanges operate several related markets. For example the energy (kWh) market may be composed of a *day-ahead market* that requires bids for each hour of the 24 hours the following day, an *hour-ahead market* for the upcoming hour, and a *real-time market* for power during the operating hour.

Exchanges also operate some kind of *ancillary service market*. These markets trade *capacity (kW)*, not energy. Generator capacity is needed for reserves, voltage regulation, and other electrical services that ensure transmission system reliability. Capacity markets are often conducted by the ISO, rather than a power exchange, because FERC requires generation and transmission markets to be independent. Some power pools require energy producers to supply the necessary capacity services with their trades, limiting the type and variety of capacity markets. Thus, which plants operate is a function of bid prices in one and possibly two markets. An example may be useful at this point.

The most familiar forms of auction involve a single product or lot of similar goods and multiple bidders. Power exchanges are the reverse, with the exchange as a single buyer and multiple sellers. Within this framework, there are two basic options for settling the auction. Starting with low bids and “bidding up” prices until bidders are unwilling to top the last, highest, bid is the most common approach and is called an “English” auction.

An alternative approach starts with a high price and successive bids are lower. This is called a “Dutch” auction (Figure 6.3). Bids can be accepted one of two ways as well. The first is the “single bid” option, where the winning bid sets the price for all sellers. The second is the “as bid” option, where sellers are paid their bid price, regardless of the winning (usually highest) bid. Power exchanges typically use the single-bid option, where the exchange accepts bids on a lowest-price-first basis, but pays all sellers the same price once the final bid has been accepted and the “high bid” price established. Bids are ranked on a lowest-cost-first basis to produce a least-cost result. The rank-ordered bids are called the *bid stack*. The final bid selected establishes the price for power for the bid period, usually a one-hour period. This bid is the *marginal price or market marginal price (MMP)* in economic terms, although it is usually called the *market price or market-clearing price (MCP)* in a power exchange. Game theory literature suggests that, after successive rounds of an “as bid” auction, sellers would begin to offer bids that were uniformly high and clustered around the last winning bid. Therefore, there is little or no difference between the single-bid and as-bid approaches.

Calif. Power (Dutch) Auction Process

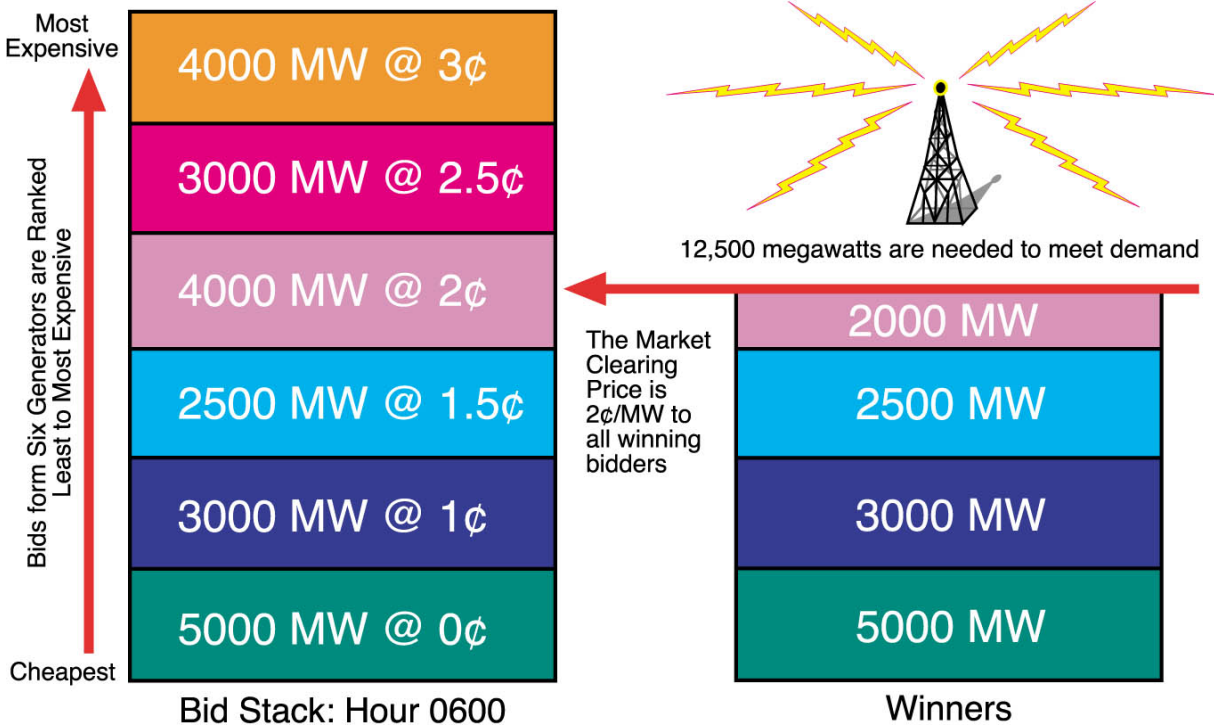


Figure 6.3. Dutch Auction Example. Assume that we have a simple market with six generators each attempting to sell energy (kWh) in the day-ahead market. The Power Exchange receives bids from all six producers that range from 5,000 megawatts (MW) at zero cents per kWh up to 4,000 MW at 3 cents per kWh (normally quoted in MW units, or \$30 per MW). A total of 21.5 gigawatts (one gigawatt, or GW, equals 1,000 MW) is bid, but demand is only expected to be 12.5 GW. The expected 12.5-GW demand can be met by production from just four bids, and not all of the power offered in the last bid selected is needed. The last selected bid establishes the market clearing price (MCP) at 2 cents/kWh, or \$20/MW. All winning bidders receive the MCP, regardless of their initial bid. As a result, the first bid selected for 5,000 MW at zero will receive \$20/MW even though they bid zero, and presumably would be content to operate for free.

The outcome of the example may seem anomalous for a couple of reasons. First, why are all winning bidders paid at the highest bid price, instead of their initial bid? Obviously, this practice means prices are higher than they otherwise could be. In fact, under regulation, the price would be the weighted average of the bids, or \$8.60/MW (0.86 cents/kWh), **plus a portion of plant capital costs**. This last point is an important qualification and is the root of the answer. Competitive markets are based on marginal prices. When the marginal price is greater than production costs, the seller earns a profit. Capital costs are paid for out of profits. If profits are inadequate, the seller is eventually forced out of business.

The second obvious question is why would anyone bid zero? There are multiple answers to this question, the most logical being that if the plant is operating in the previous hour and is expected to operate in future hours, it may cost more to shut it down than to continue to operate for another hour for free. This is especially true for large thermal plants that are likely to operate nearly all of the time (base load plants). Hence, they may be bid into the market at zero at night when power demand is low so they will be available to bid into higher priced daytime markets later. Similarly, some plants basically cannot be shut

down, especially river-based hydropower plants. Shutting down run-of-river hydro plants significantly affects stream flows, which is bad for recreation and fish. Finally, the answer to the second question is related to the first answer, namely bidders take a chance and bid low in hopes that it will position them to bid at profitable prices later in the day.

When the power auction is concluded, the losing bidders are free to bid their plants into other auctions, including the hour-ahead and real-time energy markets and markets operated by the ISO for capacity (kW), such as the operating reserve markets. The winning bids are forwarded by the power exchange to the ISO to ensure operation of the plants is compatible with the transmission system during the so-called *operating hour (OH)*. If a winning plant cannot get power over the transmission lines to where it is needed, the ISO tells the power exchange it needs to modify its bid stack. Assuming everything is okay with the initial bids, the power exchange informs winning bidders of their operating schedule. When the operating hour arrives, the ISO issues dispatch orders to the generators, telling them when to start, when to stop, and how much power to generate. The ISO operates a control center to implement these actions, and in most cases, the ISO control center replaces control centers formerly operated by individual utilities.

Restructuring means that the power exchange or pool - not individual utilities - determines which plants operate and what they are paid for power. It also means that the ISO operates the regional transmission system as an integrated unit, not as independent elements managed by each individual transmission-owning utility. As a result, utilities that formerly controlled these activities are now at the mercy of both the market and the ISO.

Competitive energy and capacity markets are at the heart of industry restructuring because they hold the promise that all power producers will have an opportunity to participate in the market to provide consumers with the widest array of supplier options and an assurance that market prices are fair and reasonable. The prices resulting from competitive markets will help producers make future plant investment decisions. If prices are too low, or markets appear to favor incumbent producers over new ones, producers will not invest in plant construction for that market. Conversely, producers should be quick to invest in new plants in markets that are open and have comparatively high prices. New plant investment is necessary to continue to meet growing power demand and for economic growth and development.

6.2.3 Transmission Under Deregulation

Deregulation of generation requires open access to transmission so that buyers and sellers can conclude their transactions with power deliveries. Transmission lines retain many of the characteristics of a natural monopoly and seem like unlikely candidates for deregulation. Nevertheless, the FERC is gradually deregulating this sector of the industry. They are starting with open access to transmission, which requires other changes, including a new way to operate the system, additional voices to guide transmission planning and operation, and so on.

6.2.4 Transmission Access Under Deregulation

Traditionally, a utility transmission system, or at least the portion within the utility's service area, was used by the local utility to move power to its retail customers. A utility may voluntarily make spare

capacity available to adjacent utilities to wheel power. The FERC now requires transmission-owning utilities to allow all market participants (power sellers, buyers, or traders) access to “spare” capacity, called *available transmission capacity* or *ATC*. ATC is calculated by subtracting transmission needed by the utility to serve its *native load* obligation from *total transmission capacity*, or *TTC*. This calculation requires estimates of two variables that can be controversial, *TTC* and *native load*. Transmission capacity varies due to a combination of physical factors and the way it is used.

On the physical side of the equation, when electricity flows through a wire, any wire, it has to overcome resistance, which generates heat. Because power lines are strung between two poles, the lines sag when they are heated. If the lines sag too much, they could touch a tree or another wire and short out, or set a fire. Therefore, there is a limit to how much power lines are allowed to sag. The amount of sag is also a function of ambient temperature and wind speed. If it is cold or if there is even a modest amount of wind, it will dissipate some of the heat built up and reduce line sag. Unfortunately, utilities don’t generally have real-time or accurate information about the microclimates that exist around all transmission line segments. They really haven’t needed this information in the past, although there are tools available for doing so, called *dynamic line rating*. Absent this information, *TTC* has to be estimated. Further, because weather conditions in the future are not known, calculations of *TTC* tend to be conservative. Another variable that affects the calculation of *TTC* is how the transmission line will be used.

Transmission transactions take one of two forms, *point-to-point* and *network*. Point-to-point service means specific transmission lines are designated to get power between two points, for example from a specific power plant to a specific load center. Network service is non-specific about where power will enter and exit the transmission network. Obviously, it is easier to calculate transmission requirements when transactions are point-to-point.

The combination of physical and market conditions ultimately defines *TTC*. Power traders are concerned about how *TTC* is calculated because limits on *TTC* translate into either fewer trading opportunities or higher transmission prices. Retail energy consumers should be concerned about this as well, as fewer trading opportunities typically translates into higher power prices or fewer retail power supply options, such as fewer green power options.

Native load presents another source of controversy. Transmission owners are allowed to set aside a portion of transmission capacity to serve customers that remain dependent on the utility for retail electricity service. In states that haven’t deregulated, this is essentially all retail customers. Thus far, all of the states that have deregulated (with the exception of Texas) have requirements for the incumbent utility to continue to provide retail electricity service to customers that either do not choose new suppliers or that are unable to get service from competitive suppliers. These are called *default service* customers and the utility is called the *default service provider* or the *provider of last resort (POLR)*. The local utility can set aside transmission capacity for these customers also. How much capacity they set aside is a function of both how many customers the utility has to serve and their expected consumption.

Because default service customers could choose alternative suppliers at any time, and customers can return to default service at any time the utility is challenged to come up with an accurate estimate of the amount of transmission capacity it may need or given this uncertainty, how it would use the transmission system to serve them. Subtracting native load requirements from *TTC* is the first step in estimating *ATC*, or the amount and location of transmission available for other transmission users. If the utility is overly

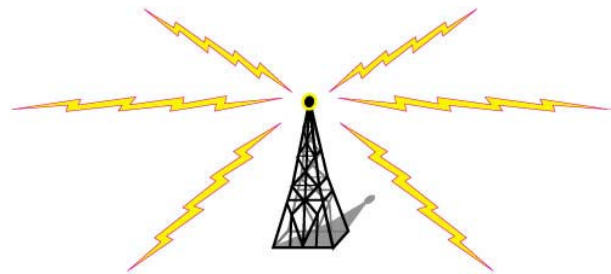
conservative with how it estimates native load requirement, it reduces the amount of transmission capacity that is available for other users. Initially, FERC allowed transmission-owning utilities to estimate native load requirements without much supervision or direction. Concerns about potential abuse of this discretion are now leading FERC to require native load to compete for transmission capacity reservations on par with all other transmission users.

Available transmission capacity is used by first reserving the needed capacity. Transmission users compete against each other to reserve capacity out of the ATC pool. Reservations require the payment of a small fee, with the balance due when the capacity is actually used. If it is clear the capacity won't be needed, it has to be released back to the transmission owner before the reservation time passes. Transmission capacity can be reserved for various periods of time into the future. Transmission capacity can be reserved by anyone, including speculators who intend to sell their reservations. This is a risky business, as transmission capacity is not scarce most of the time (about 95%).

When transmission is *constrained*, power traders may be willing, or forced, to pay high prices for capacity from those who hold reservations. There are a variety of ways of setting prices to resolve transmission constraints, including "nodal" and "zonal" pricing of transmission. The goal of all of these is to provide a market mechanism, a price, to eliminate the constraint by forcing price-sensitive power sales off the grid until the constraint is removed. This whole aspect of transmission deregulation is still evolving, as current transmission constraint management techniques have not fully resolved the issue of how to increase transmission capacity so that current constraints are removed.

6.2.5 New Institutions: ISOs and RTOs

Competitive generation and transmission markets merge in the ISO, despite the fact that the markets themselves operate independently. A central point of control is necessary to ensure system reliability. Consequently, the ISO has become the heart of the new competitive electricity industry. The ISO, typically, replaces old utility control centers. This doesn't happen immediately, but over a short transition period. ISOs are required by FERC to be broadly representative of all market participants, not just transmission owners. This includes representation on the management board from each segment of the market so that no market segment has veto power over any other. Once formed, the ISO adopts its own rules and procedures and becomes "independent" of transmission owners. If the ISO is formed from a pre-existing power pool, it normally adopts a modified set of those rules and procedures. The ISO is responsible for all transmission functions; however, each ISO performs more, or less, of these itself, depending on its charter. For example, some ISOs may issue instructions to existing utility control centers rather than replacing these institutions.



ISOs came about because FERC wanted assurances that transmission system operations would be independent. Without these assurances, FERC indicated it may not allow utilities to trade power at market-based prices in wholesale markets. Utilities have been slow to implement ISOs, especially ISOs with appropriate scope (functions) and scale (geographic coverage). In response, FERC recently announced that it won't allow utilities to continue selling power at market-based rates unless they form large ISOs, called Regional Transmission Organizations (RTOs). FERC initially proposed that most of

the continental US (and parts of Canada and Mexico) fall into just five RTOs. This proposal was widely criticized as impractical and overly expensive by many utilities and some regulators, although power traders and merchant power plant developers generally supported it. Regulators were critical primarily out of fear that they would lose control of transmission to FERC and because of perceived costs. FERC is presently entertaining proposals for alternative RTO configurations. FERC still intends the nation to be largely covered by RTOs and is continuing the process with utilities and other stakeholders (Figure 6.4).

FERC and some of the proposed RTOs have commissioned cost-benefit studies to counter claims that RTOs are too expensive. So far, these studies indicate that RTOs will deliver more benefits than costs. Some of the most contentious issues in RTO formation revolve around opportunities for transmission owners to make profits that are greater than allowed under regulation. This is similar to the debate that occurred when generation was deregulated. Although the outcome is still unclear, leading utilities are divesting their transmission to new, for-profit transmission-only companies, or transcos. One state, Wisconsin, has directed its utilities to form a transmission-only company, even though the state has no current plans to deregulate.

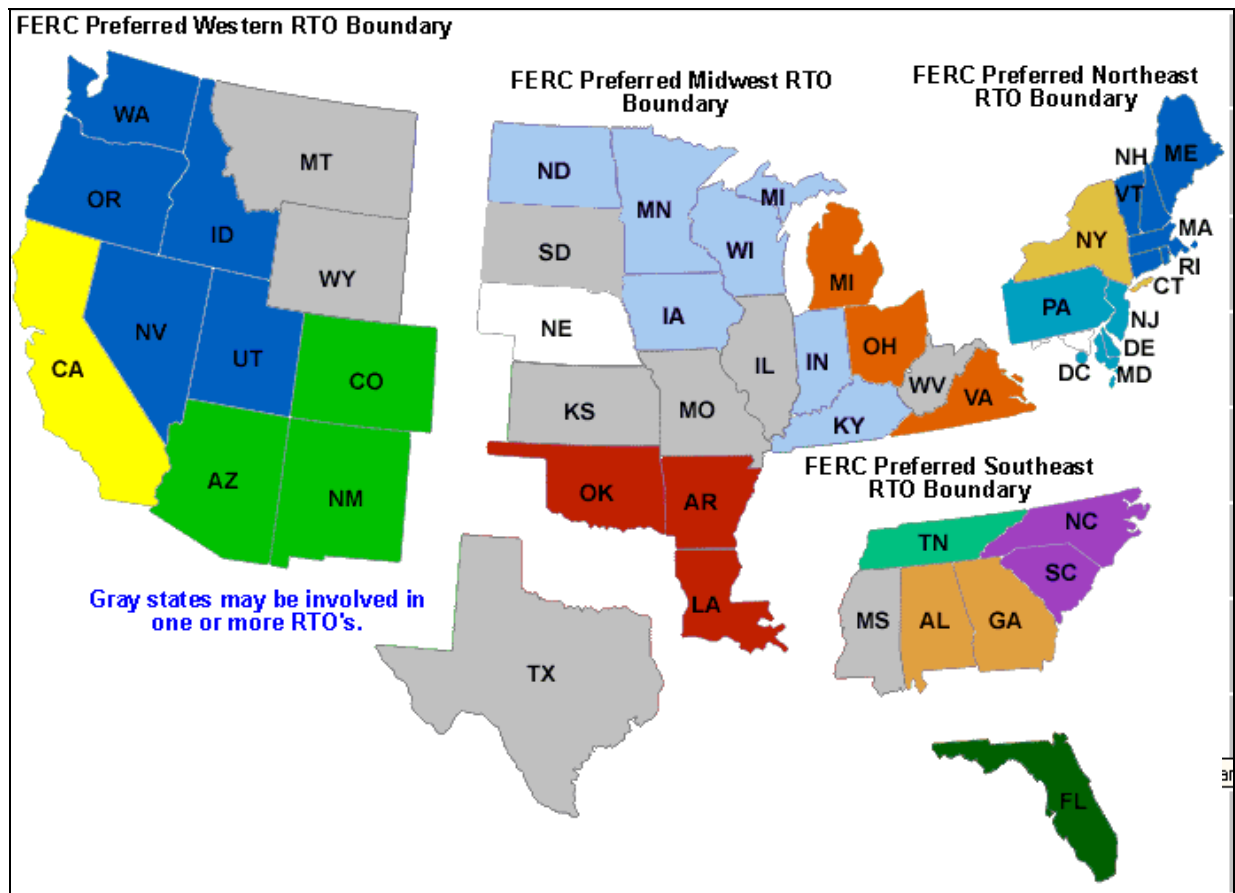


Figure 6.4. Currently Proposed RTO Boundaries

6.2.6 Reliability and Reserve Margins

The primary mission of an ISO is to facilitate commercial electricity transfers without compromising reliability. To do so, the ISO has responsibility for scheduling transmission transactions and maintenance. It may also have operational responsibility and dispatch generation and operate the integrated transmission system. System reliability is maintained, in the long run, through the provision of adequate transmission capability (an ISO planning function) and, in the short run, through generation reserve margins. ISOs procure reserve margins differently depending on their charter. Typically, reserves are either purchased by the ISO from a reserve market it operates or are a required component of transfers over the transmission system. In the latter case, a market participant wishing to use the system will have to designate reserves before the ISO will execute the transfer. Most of the time, market participants designate generating capacity within the ISO's area to provide needed reserves. This is similar to the pre-deregulation practice of having idle capacity available in case of unplanned events. Load curtailment could substitute for reserves in some cases, but few ISOs specifically encourage load curtailment as a form of reserves. FERC envisions RTOs expanding on these functions. It anticipates the RTO having full operational control over the power grid itself, or through an ISO. It anticipates RTOs will treat demand relief as a legitimate form of reserves.

6.2.7 Ancillary Services

The ISO is also responsible for providing ancillary services in addition to reserves. These resources are typically provided through contracts with generation operators. Some generators may be required to even out voltage and frequency variations in real time or to stand ready to start-up in case of system collapse, so-called *black-start capability*. The most familiar of these specialized ancillary services is providing for transmission losses. Transmission transfers result in losses of electrical power on the order of 4 to 7 percent. Market participants need to make up for these losses. Some ISOs operate markets for losses where market participants can purchase sufficient power to cover these losses. Other ISOs require market participants to provide extra generation to cover their losses. The technology exists to provide some of these ancillary services from demand control and distributed generation, although there is no requirement for RTOs to consider either as a source of ancillary services. This is expected to change as RTOs become established and new technologies are adopted.

6.2.8 Tariff Administration and Back Office Functions

FERC's objective in encouraging ISOs is to facilitate power transfers within and across the ISO transmission grid. ISOs facilitate power transfers by reducing the number of parties that must be contacted to arrange transmission to a single point, the ISO. As a consequence, the ISO also has responsibility for managing financial, as well as electrical, transactions. It does so as the *tariff administrator* for participants in the ISO.

One of the primary barriers FERC is attempting to address with ISOs is to simplify power trading by reducing "*rate pancaking*." Rate pancaking is the end result of a power trade that crosses multiple transmission lines to "stack" a different rate for use of each utility's transmission lines. FERC expects ISOs to have a single tariff that permits market participants to move power across the ISO grid for a standard fee. Adopting a single tariff is complicated by the fact that the cost of each utility's transmission

system varies, primarily based on its age. (Older systems are less expensive because they were often constructed when costs were less and they have depreciated more than new systems.)

As a result most ISOs have adopted a transitional tariff that reflects system cost differences initially but gradually converts to a single standard fee. The appropriate length for this transition is a topic of discussion between the ISOs and FERC. FERC favors a short transition, while transmission-owning utilities favor a longer period. Utilities are concerned that a short transition may not allow them to recover the same amount of transmission costs they would under regulation. Single transmission tariffs also pose problems for government-owned utilities that own transmission. These entities, typically municipalities and cooperatives, do not earn a profit and have no way to absorb a loss of transmission revenues without raising consumer rates. This would result in an unfair subsidy of transmission users by retail consumers. This issue is somewhat more pressing for government-owned utilities as their transmission infrastructure tends to be newer, on average, than that of investor-owned utilities.

6.2.9 Billing, Settlement, Dispute Resolution

ISOs are responsible for collection of fees, not just for transmission system use, but often for power and capacity markets because of their role as tariff administrators. This requires the ISO to have a sophisticated *settlement process* that provides a financial audit trail for power movements across the transmission grid. This system normally includes a dispute resolution process for participants who want to challenge questionable transaction fees. During this process, participants who have not fulfilled all of their contractual commitments may find significant charges from the ISO to recover costs the ISO incurred to ensure reliability. For example, if a participant decided not to honor a bid to operate generation, the ISO would have to procure make-up power from its reserves or the energy market. The participant that defaulted would have to pay the ISO for its costs, which could be substantial.

Through this role, the ISO protects retail consumers from financial defaults that might otherwise result in a system emergency and potentially a blackout. Typically, an ISO has very few capital assets of its own, yet it essentially provides the “bank” for billions of dollars in market transactions. Consequently, it cannot absorb the default of a market participant. One way ISOs (and power exchanges which have the same financial exposure) protect themselves is to have a provision in their organizational charter that allows them to collect for any defaults by dunning solvent market participants. This provision was exercised in California leading to many complaints and attendant review of the practice. Regardless, ISOs have to provide some form of fiscal safety net, ultimately underwritten by the market participants, to ensure participants of their financial integrity.

6.2.10 Planning

Another one of the primary reasons FERC supports ISOs, and now the larger RTOs, is to support coordinated transmission planning and expansion. The greatest threat to the transmission grid today is that it is over-extended because of increased power use and the way the transmission system is being used to support an ever-increasing number of transactions. To some extent, transmission lines in an RTO environment are like freeways. Once in place, they are quickly overwhelmed with traffic simply because they make transactions so much easier.

The most critical problem ISOs and utility transmission systems everywhere face is the need to either increase capacity or find a better way to ration existing capacity. FERC Order 888 requires transmission-owning utilities to increase system capacity in the face of wholesale customer demand. Construction costs are supposed to be recovered from the market participants that use the new capacity. This new capacity is likely to be very expensive compared to use of the existing system. As a result, market participants are each waiting until someone else agrees to use, and pay for, new power lines. This is a stark contrast to the period prior to deregulation, when system expansion was solely a utility responsibility and cost recovery from retail consumers was virtually guaranteed. Similarly, in the face of RTO proposals, state regulators have been reluctant to allow utilities to expand transmission lines for fear state-ratepayers will end up paying for transmission lines used primarily for interstate commerce.

ISOs typically are responsible for planning for the entire ISO grid. These plans are supposed to optimize the operation of the grid as a single entity, ignoring the fact that it is composed of multiple units that are owned by individual utilities. Multiple owners further complicates planning because transmission system additions change the way power flows in the system, which may decrease revenues to one or more transmission owners. Although ISOs may have planning responsibility, they may not have the authority to initiate construction. Moreover, as new entities, they may lack the status of existing utilities before siting agencies and may even lack the eminent domain privileges that come with being a utility.

In the evolving world of transmission policy, planning is an area where a real distinction between ISOs and RTOS begins to emerge. An RTO may have an ISO to operate the transmission system, while reserving to itself the planning responsibility. Clearly, FERC favors the larger scale RTO for planning and system expansion than the ISO. Because transmission systems need to be designed and operated as a single unit, the larger that unit for planning purposes, the larger the power trading platform.

6.2.11 Distribution

Restructured power and transmission markets and operations are largely invisible to most retail customers. The most visible evidence of deregulation is at the distribution level because retail deregulation, or customer choice, primarily affects the procurement of power. Delivery and most other utility services are unaffected, at least initially.

6.3 Customer Services after Deregulation

Deregulation and industry restructuring will change the kind of services distribution utilities will offer to customers under regulated rates because the cost of services at the distribution level will be the primary focus of future rate regulation. Some of the historic services offered by distribution utilities will almost certainly be eliminated, others may change to a fee-for-service basis, and third parties funded by ratepayers will perform others. A preview of likely changes follows.

6.3.1 Service Offices

Customer service offices provide customers with a convenient way to pay bills, open and close accounts, and resolve complaints, generally about power costs, not distribution service. Several large utilities have replaced customer offices with centralized call-centers and internet-based billing and service tools. In most cases these systems are more efficient for all concerned, as records are immediately available, most

can be accessed 24 hours a day, waiting time is significantly reduced, and operating costs are reduced. As a result, these services are being aggressively marketed to all utilities. Such services will be necessary, in fact, as power providers serve ever larger, and geographically distant, customers. In the long run, customer service offices are likely to become less common. Some smaller utilities, especially customer-owned utilities like municipalities and cooperatives see offices accessible to customers as one of their key competitive advantages, and they expect to exploit it to remain local and independent.

6.3.2 Outage and Repair Service

When the lights go out, retail consumers will probably still call the local utility for service restoration, regardless of where they purchase their power. Many regulators are evaluating *performance-based regulation (PBR)* of local utility functions in the post-deregulation era. This is possible because regulated utility functions will be significantly reduced and streamlined after deregulation. PBR focuses on a small number of criteria that are used to assess utility performance. If the utility meets or exceeds performance expectations, it is rewarded with a slightly higher rate of return. PBR has been used to regulate local telephone carriers. Outages and restoration times, along with processing time for new connections, are commonly used performance metrics in the telephone field. It is reasonable to expect utilities to respond even faster in these areas under PBR. Liability for power outages and service interruptions will also change, so that it is appropriately assigned to the power supplier or the distribution utility. This liability will increasingly become the subject of customer service contracts, albeit in the fine print.

6.3.3 New Connection and New Service Requests

The local utility will probably still be the point of contact for connection of new facilities and for expansion of existing ones. In the past, service connections were fairly simple. In the future utilities may have a variety of ways to meet service needs and may offer a range of options. For example, they may offer on-site generation in lieu of expanded distribution service. Some urban utilities are exploring district heating and cooling systems as an additional service. This could provide an alternative to expanded electrical service in some cases.

6.3.4 Marketing

Although local utilities will still be marketing electricity as a beneficial service (e.g., “live better electrically”) and encouraging new customers to locate in their service areas, they may not be marketing electricity *per se*. Deregulation legislation in all states prohibits the distribution utility from trying to compete for retail electricity sales. The local utility may have a subsidiary that does so, but it must keep that operation isolated from the distribution service function. In most states the local utility is barred from referring customers to competitive suppliers or making supplier recommendations. It will be interesting to see how much marketing regulators continue to allow as deregulation goes forward.

6.3.5 Metering and Billing

Both the power seller/marketer and the local utility have a need to meter customer usage. Power sellers need to bill for power use and the distribution utility needs to bill for use of the power lines and other services. Power marketers are allowed to take over the metering and billing function in some states. In a few, new power suppliers are actually required to take over metering and billing for their customers.

Where they are able to do so, these firms can provide customers with multiple locations with integrated bills, including changing billing cycles so that all bills arrive and come due at the same time. Regardless, the local utility may continue to meter and bill customers in most states and to offer this as a service to marketers in others.

Access to customer billing data will be strictly controlled after deregulation. This is to prevent the local utility from gaining an advantage in the power sales marketplace. As a result, most utilities are adopting rules that govern how customers obtain access to billing records. It is important for customers of new suppliers to retain copies of their bills so they can be used in future solicitations. In other words, once you change suppliers, do not expect to be able to go back to your old supplier for your billing data.

Along with new metering and billing agents also comes new meters and meter installation and maintenance expenses. A new meter for a large, time-of-use customer typically costs around \$1,000 installed. This cost needs to be paid for out of energy bill savings. In some cases, it may cost more in metering costs to switch to a new supplier than the switch will save you in energy costs. New meters, especially the time-of-use variety, have many innovative features including the ability to be accessed over the Internet in near-real time. Some can be configured to also record natural gas and water usage and to set off an alarm or call a pager if demand is too high or increases too rapidly. Unfortunately, there are few standards for metering and billing and one vendor's meter rarely works with another vendor's billing software. There are activities underway in the industry to develop standards, but these will take a few years to take full effect.

6.3.6 Energy Efficiency and other Demand Management Services

Retail consumers have come to expect utility advice on energy efficiency, equipment selection, and similar support, including audits, rebates, discounts, and financing. Generally, these services are provided at the direction of regulators, not as voluntary programs. Deregulation presents a bit of a quandary for all concerned. Regulators and legislators generally would like to see these services continued. At the same time, the original purpose of these programs was to reduce energy use or to change energy use patterns. These are no longer the concern or responsibility of the distribution portion of a utility once customer choice is in effect. Moreover, these services only benefit the customers who use them, but must be paid for by all retail customers. This isn't an equitable situation for either the utility or consumers.

Most deregulation legislation still requires these programs, although funding is usually in the form of a surcharge on the bill. Funds collected from the surcharge are dedicated to energy efficiency and renewable projects, often through programs operated by a third party instead of the utility. It is not clear if these surcharges will continue after deregulation is complete, because of equity concerns. The authorization for some of these programs has expired in some states and, so far, it has been renewed or extended in every case. It isn't clear if this reflects a continued commitment to these programs or a reflection of the fact that most retail customers continue to be served by the local utility under default service rates.

Recent price volatility and isolated power blackouts caused by local power shortages have renewed interest in load management and other energy-efficiency programs. Unfortunately, these programs require a different design than previous, utility-run programs, as they need to respond to market failures as well as potential power shortages. Fortunately, some of the competitive wholesale markets value load

curtailment and are willing to pay customers who interrupt their loads as much as they would pay a peak period generator. These markets are not yet well developed, but recent events have provided new urgency to get demand relief programs up and running. Unlike previous load control programs, customers will probably participate in these new demand relief efforts through their power supplier or the ISO, not the local utility.

A large number of competitive energy suppliers are offering energy audits and energy-efficiency project financing to their customers. Often the energy audits are free to commercial and industrial customers because they give the marketer a better understanding of the loads it is serving. Marketers use this information to structure their energy purchases so they can make a larger profit. They may also recommend operational changes to the customer that have a similar effect. Although the jury is still out, it does appear that the market will step in to replace some utility-sponsored energy-efficiency programs.

6.3.7 Renewable Energy Resource Programs

Under regulation, utilities also used ratepayer funds to develop renewable energy resources. Distribution utilities will be prohibited from marketing power from these, and other resources, after deregulation. Consequently, distribution utilities will not be able to collect ratepayer funds specifically for development of renewable generation for commercial power sales. Nevertheless, marketers in several of the states that have opened to competition have stepped in to fulfill consumer demand for power from renewable sources. In fact, offering green power is one of the key marketing strategies used to sell power to residential consumers. With few exceptions, green power, or power from renewable resources, sells for a premium over power from conventional sources. Generally, but not uniformly, the savings from deregulation are not sufficient to offset the green power price premium. This should change as competitive markets and green resource developers mature.

Regulated utilities also use ratepayer funds to conduct research. Many utilities have voluntarily reduced these investments pending deregulation. Often funding has shifted from ratepayers to stockholders so that the benefits can be reserved for stockholders instead of shared with ratepayers. Several deregulated states continue to require utilities to collect funds for R&D from ratepayers, but these funds and the resulting research are managed by a third party.

6.3.8 The Texas Exception

For many reasons, Texas is unique among U.S. utilities. Because of this, Texas took a different path towards utility deregulation. In a marked departure from all other states, Texas required utilities to form new subsidiaries to serve retail customers. Retail distribution services would be provided to all retail energy service providers, including these new utility subsidiaries, on an equal, non-discriminatory basis. These new energy service providers would be the “customers” of the distribution utility. Retail customers would, in turn, be the customers of the new retail energy service providers. When it adopted this approach, it was expected that retail customers would call their energy service provider in case of an outage, not the distribution utility. In practice, that hasn’t worked. Retail customers were not prevented from calling the distribution utility, although they can call their energy service provider if they wish.

7.0 Coping with Utility Restructuring – Guidelines for Federal Customers

To this point, this Primer has focused on the utility industry itself, rather than on impacts on specific customers or federal facilities in particular. This chapter will address those issues, beginning with a customer-centric recap of the previous chapters and a 10-step program for coping with utility industry restructuring.

7.1 Recap – What Does Utility Restructuring Mean to Me?

Components of Energy Bills

Energy bills typically are composed of several components:

- a commodity charge for energy
- a long distance delivery charge (transmission for electricity, pipeline transportation for natural gas)
- a local utility distribution charge
- a “demand charge” that covers utility service fees that are not fully recovered in the commodity charge
- a fee for local utility operations.

Local utility operating fees may be further unbundled into

- general and administrative expenses
- metering and billing
- a public benefits fee to pay for energy management programs and low-income customer assistance.

Most of these charges are subject to deregulation of their price. Deregulation of the price of energy bill components is done by the Federal Energy Regulatory Commission (FERC) (for wholesale energy prices and long-distance delivery charges) or State regulatory commissions (for all other charges). State legislation may launch the deregulation process; however, state utility regulators usually have some say in the process, even if it is only to set prices for services that are not deregulated. Many small utilities are not subject to government regulation and can choose to deregulate on their own, although few have done so.

7.1.1 What has been deregulated?

Wholesale electricity and natural gas commodity prices were deregulated by the FERC in the last decade. FERC has partially deregulated aspects of gas pipeline transportation rates. It is in the process of extending a similar form of deregulation to electricity transmission.

7.1.2 Setting the Cost of Energy - Wholesale

Wholesale electric and natural gas deregulation means the cost of wholesale natural gas and electricity to wholesale customers (and non-core natural gas customers) is no longer based on cost-plus regulation but prices set in competitive markets. Commodity markets tend to be highly volatile, with prices moving up and down on a daily basis depending on supply and demand, weather, and other considerations. Commodity price movements reflect perceptions about future events as much as present conditions. The good news is that commodity markets provide a variety of ways to fix prices using standardized financial instruments. The bad news is that price uncertainty forces retail customers to resort to the use of those instruments to ensure price stability.

7.1.3 Setting the Cost of Energy – Retail

Commodity gas costs are the primary cost of retail natural gas prices. As a result, virtually all retail natural gas customers pay prices that follow wholesale natural gas prices. Many states have deregulated retail natural gas prices. As a result, retail prices follow wholesale prices with only a short lag time. If retail gas prices have not been deregulated, the retail gas utility generally has to ask state regulators to change prices. This introduces a longer lag between wholesale and retail price changes. Regulators may want to ease the impact of sudden price spikes by spreading costs out over a longer period of time, which may result in retail prices that are much higher than prevailing wholesale ones.

Although roughly half of the states have embraced retail electricity deregulation, only a few have truly competitive retail electricity markets. Instead, regulators have provided retail customers with a shelter from the volatility of wholesale electricity market prices in the form of default service rates provided by the incumbent utility. Eventually, these shelters will be removed and electricity customers will be exposed to commodity prices like natural gas customers are. Deregulation of electricity has resulted in supply options that include power from renewable resources, often at competitive prices. Renewable power supplies can be less volatile, albeit somewhat higher, than the market price of electricity.

7.1.4 Setting Delivery Costs – Wholesale and Retail

FERC has launched a process to deregulate some aspects of wholesale gas and power delivery, although both remain regulated for the most part. There are periods when the demand for transportation/transmission by wholesale traders exceeds available capacity. FERC believes that these capacity constraints should be relieved using market mechanisms. In other words, customers who do not want to be interrupted may see higher rates periodically. In addition, FERC has deregulated other aspects of transmission service. These account for less than 10 percent of energy costs, on average, but scarcity (or price manipulation) can drive these costs quite high. Thus, even though they compose a fraction of energy use, they can constitute a large fraction of energy cost. Consequently, retail customers may face volatile prices due to transmission costs as well as energy costs. Prices for energy and transmission typically increase for the same reasons and, therefore, are likely to do so at the same time.

Retail utility delivery services are expected to remain regulated. As the industry restructures, local utilities may be confined to a distribution-only business model. It is likely that delivery rates will be reformed from the current per kilowatt-hour charge to something like a flat access fee or a demand charge.

7.1.5 Other Retail Charges

Some states have deregulated metering and billing services and changed the way public benefits fees are distributed. These charges are a minor part of the retail bill; nevertheless, further changes to these fees should be expected.

7.1.6 The Bottom Line

The utility industry has entered a period of change that is unprecedented. These changes should result in increased access to a broader array of energy solutions that will be competitively priced. In most cases, and in most areas of the country, this should result in an overall reduction in utility bills. Some areas of the country may see slight increases. As expected innovations in utility delivery and management enter the mainstream, average costs should decline for all customers. Unfortunately, innovation is being delayed while uniform wholesale and retail market rules are being worked out at the state and federal level. Until they are, retail customers are more likely to see price volatility than cost savings. Alternatively, most retail customers would be looking at rate increases if deregulation was not implemented. Unfortunately, it is difficult to “bank” savings from what might have been.

7.2 Guidelines for Coping – A 10-Step Program

The energy conservation ethic is often the primary driver behind energy management practice. This ethic may be the only motivation for utility customers with regulated rates. The volatility of market-based energy commodity prices periodically provides all retail energy customers with an energy management wake-up call in the form of price spikes or supply disruptions. Unfortunately, customers that do not have an energy management program or strategy in place can only react to prices and ride them out. This can lead to some tense discussions with individuals responsible for paying utility bills! There are some simple steps that all energy and facility managers should take to get control over energy use. Ideally, most of these steps will be taken prior to a price or supply crisis.

7.2.1 Step One – Data Collection

As the maxim goes, you can't manage what you don't measure. Figuring out how to manage energy use can be a bit of a mystery, but it is a function of things that can be measured and monitored. The kind of data that should be collected at a minimum include

- Utility billing information, such as the location of each utility meter and the associated meter number, type, and utility account number.
- Utility billing data, including at a minimum, all monthly meter readings and, if available, hourly or sub-hourly usage for electric meters. Hourly meter readings are generally available for large customers (those with some kind of time-of-use rate). Hourly measurements of electricity (and gas) use can be taken by the utility and others for a fee. It may be worth it.
- Weather measurements. At a minimum, daily highs and lows, ideally hourly temperatures to match up with hourly metering data. Weather bureaus, specifically NOAA, usually have good records that are close enough to most sites.
- Building schedules sorted to correlate to the meters that serve them.

- Functional schedules, including such things as troop deployments for military installations, training schedules for office workers, check processing days, and so on.

Assemble this information into some kind of database so it can be graphed and various pieces of information compared. Are there obvious patterns? Is energy use greatest when it is hot or cold? Do functional schedules increase or decrease energy use? If hourly data is available, does energy use correlate to the building schedule? If not, why not? Take this analysis as far as you can. Seek out help from energy audit professionals to pick up where you leave off. Share the information with others. You might be surprised what they can tell you about patterns you notice.

7.2.2 Step Two – Review Your Utility Bills

Utility bills are a rich source of information. Compare trends in bills and cost/kWh. When are the highest bills and highest costs/kWh? Compare trends in demand charges and total energy use. Calculate monthly load factor. (This is described elsewhere in the Primer, but to summarize, it requires dividing total energy use by the number of hours in the billing period, i.e., 720 for a 30-day month. The result is average use per hour. Divide this number by the peak demand value on the utility bill. You should get a number that is less than 1, probably around .6. This is a ration of how “peaky” your consumption is. Loads that are peaky, or have low ratios, typically pay a lot in demand charges compared to energy. Peak loads are often easy to reduce and can significantly reduce the total utility bill. Track the change in load factor from month to month and year to year. Is there anything that correlates with these changes, such as seasonal temperature, water use, or the addition of new electrical equipment?

There is an entire industry that is based on comparing customer rates to other rates offered by the utility to see if changing from one to another will save money. This is not a difficult comparison to do and often utility representatives will help you do it. Customers are assigned to a rate class based on the amount of power they use and the kind of customer they appear to be to the utility. This is a judgment call. You should review what other rates are available from the utility for customers that fit your description. One of these may be a better fit, in which case you should request that you be changed to that schedule. Sometimes it is best to wait until you have taken some energy management actions first, such as reducing peak demand (improving load factor), as that may qualify you for a better rate.

Very large customers may want to explore taking electricity service (or natural gas) directly from the transmission line or gas pipeline. This may require the customer to seek wholesale status through the state regulatory commission. This is an involved process that the local utility will generally oppose. It also requires the customer to take much more responsibility for meeting their energy needs. Accordingly, it should not be taken lightly. Nevertheless, it may be worth exploring, especially for customers that may want to add generation on-site.

7.2.3 Step Three – Reschedule Major Energy-Using Activities

Changing the schedule of energy--using activities is the key to active energy management. When high energy-use activities stack up, they result in high peak demand. If these activities can be spread out, demand charges will be lower. Changing activities will require negotiation. As a first step in that process try to prioritize the various activities in terms of mission from critical to optional. Use that as a basis for constructing a pro forma schedule or conducting a pilot study to see how energy bills are affected. It is

important to recognize that energy uses within buildings, even “critical” buildings like hospitals, also vary in importance. Try to identify the major energy uses within buildings for this exercise as well. During the California energy crisis, some federal facilities went without lights and air-conditioning altogether. This may not be appropriate for high-rise buildings, but reducing lighting and air conditioning in the late afternoon may be practical.

7.2.4 Step Four – Assess Energy Price and Use Trends

Facility energy use changes over time, often dramatically. That is one reason why customers often find they are on the wrong utility rate (Step Two). Try to project energy use trends forward 5 or so years. This will require discussions with tenants. Getting them thinking about the impacts of their plans on energy use is also useful. Does this exercise tell you anything about future energy use levels? Could these trends qualify you for a more favorable rate in the future? Consult with industry experts, starting with utility staff and Energy Information Administration sources, about future energy price trends. What do these tell you about future energy bills? What can you do today that could put you in a more advantageous position? Who might be an ally to help you make these changes, the utility, your ESPC contractor, utility-funded public benefits funds, the local energy extension service or DOE regional office, or FEMP?

As noted above, transmission costs and constraints will figure more prominently in future electricity cost and supply scenarios. As a result, it will be increasingly important to monitor the local transmission situation when making power supply and price forecasts. Being aware of where new power plants are being located, and potentially opposed, is also part of the picture. Large federal installations may be attractive to power plant developers, both as sites and as potential wholesale customers (see Step Two). Again, local utility staff should be able to help with this assessment, along with resources provided by FEMP (such as the RTO section of the FEMP Restructuring web site).

Remember, when you look forward and plan, you have the luxury of time to change your future.

7.2.5 Step Five – Assess Energy Efficiency Potential

The good news for federal customers is that energy efficiency is NOT dead. It is not only alive, but is strongly encouraged by the Administration’s National Energy Plan. Not only that, but most states actively support energy-efficiency efforts, as does FEMP. A comprehensive listing of energy-efficiency resources is available on the EERN web site. State-level resources are listed on the FEMP Restructuring web site.

Thanks to investments by EERN and others, the state of the art (and commerce) of energy-using equipment continues to advance. A recent issue of Consumer Reports had an article about whether it was more cost-effective to repair or replace a variety of residential appliances. Surprisingly, the article concluded that advances in energy efficiency have made it NOT cost-effective to repair many home appliances because the cost of a new, replacement appliance can be made up in reduced energy costs! This is also true for a variety of energy-using equipment including the office computers, monitors, and printers that are commonly used in federal facilities. Many of these can be purchased with Energy Star features and almost all current models use less energy than their predecessors. Finally, federal facilities have their choice of third parties to invest in energy efficiency, including energy service companies (ESCOs) and

utilities. FEMP-supported ESPC and USEC contracts provide private-sector investors with both a mechanism and an incentive to search out energy efficiency investment opportunities.

Facility managers can utilize the available third-party resources to identify energy efficiency opportunities or can do so on their own with locally available resources from the state or universities. In some cases, commodity energy suppliers are willing to provide resources to explore efficiency opportunities. In fact, there is a business model, commonly called the Total Energy Management, or TEM approach, that some energy suppliers employ. The TEM model offers power buyers discounts on energy price in exchange for first right of refusal or exclusive rights (the model varies) to energy audits and efficiency retrofit investments. The underlying logic is that power can be procured for a site, at a discount, under prevailing consumption levels and that the contractor can change the ways energy is used to earn additional profits in the supply market. Fundamentally, this business model is sound. Unfortunately, the logistics involved have proven to be sufficiently complex that the pay-off often extends beyond the initial contract period. In other words, the investments don't pay off fast enough for the contractor to reap sufficient savings to pay back the initial investment. Nevertheless, there are a few examples that indicate this approach can work.

In summary, there are many opportunities to improve the overall energy efficiency, and especially the energy use patterns, of federal facilities to pay back the cost of these investments. Fortunately, there are also a variety of sources of investment capital to implement these changes. Staff at FEMP, in the labs, in DOE regional offices, and in the private sector can help.

7.2.6 Step Six – Assess New Technologies

As indicated in the last step, technology continues to change. Many of these changes are based on energy efficiency in the assumption that higher acquisition costs can be justified based on lower energy and other operating costs. Another promising new development is in co-generation and small-scale distributed generation technologies. Power generation using fossil fuels wastes a significant amount of energy in the form of waste heat. This heat could be captured and used to supplement the use of other energy sources to provide heat, motive power, hot water, and steam. It is not economical, however, to transport this heat from remote power plant locations. If, instead, the power plants are located on, or adjacent to federal facilities, it may be economic. Better yet, the facilities can be located at the point of use if they are small enough. This is the market being targeted by distributed generation technologies, including reciprocating engine gen-sets, micro-turbine generators, fuel cells, and new energy storage technologies, most of which are being marketed to either small users (i.e., residences) or to small end uses.

Although the thermal efficiency claims of dealers are impressive, the economics of distributed generating technologies are challenging for several reasons.

- First, the initial capital costs are greater than the capital costs of larger generating plants. In other words, these options are not cheaper initially than utility-scale power plants.
- Second, these technologies are not as efficient as utility-scale power plants. Put simply, they cost more to buy and they burn more fuel.
- Third, these devices all use conventional fuels, all of which cost more for consumers than they do for power plant operators. For example, natural gas costs the typical commercial customer about twice as much as it does a utility.

- Finally, distributed generators are much cleaner than they used to be, but they still produce emissions and have to be permitted by environmental or air quality boards. These permits may come with restrictions that limit total hours of operation and may even restrict operation during the air-quality action periods associated with the highest electricity costs. In other words, you may not be able to run the units when you need them most.

As a practical matter, distributed generation isn't economic for a mass market just yet. Nevertheless, that is clearly the goal of the industry and there are substantial industry and federal resources betting that distributed generation will become economic for a mass market in the near future. Clearly, distributed generation is a technology to watch.

Another emerging technology, or suite of technologies, is associated with demand control in response to wholesale and retail prices in real time. Power system operators have to match power demand and generation minute by minute. To do so, system operators pay generators to vary power plant output. Sometimes, plant operators demand very high prices to do so. As a result, the FERC and some states have directed system operators to include "demand relief" as an option. Instead of changing generation to match demand, consumers are paid to reduce demand to match available generation. There are a variety of products and vendors that can help consumers tap into these markets as they develop. Again, this is technology to watch.

7.2.7 Step Seven – Monitor Renewable Resource Developments

Renewable resources (wind, solar, geothermal) have a major advantage over conventional power plants, namely they have no fuel costs. Although it still costs more to construct renewable energy projects, these costs are declining and federal policy continues to provide incentives to reduce the cost of renewables. As a consequence, the industry is growing rapidly and the scale of some renewable generation project, particularly wind farms, is increasing. Currently, wind farms are being developed that have a capacity of 300 MW or more, on par with utility-scale combined-cycle combustion turbine power plants. Some renewable resources are more cost effective when they are developed in large-scale projects, like wind farms.

Most renewable resources can be developed on a much smaller scale and lend themselves to on-site power development, for example solar photovoltaic, geothermal (both in heat-pump and power generation applications), and certain wind turbine designs. One of the advantages of on-site renewable resource development is that it competes against the delivered cost of power, not market price. In other words, each kilowatt of power from an on-site generator displaces one that would be purchased from the wholesale market and delivered by the local utility. If renewable generation is available during peak demand periods, it also decreases the utility demand charge.

The benefits of renewable energy purchases also include

- diversification of domestic energy sources
- reliance on sustainable, indigenous resources
- reduced vulnerability of the power system due to outages of large power plants
- reduced environmental impacts
- potentially more stable power prices.

These benefits can be obtained without development of renewable resources on-site, or from a direct purchase of renewable power, simply by purchasing a “green tag.” Essentially, a green tag is a tradable right to the benefits associated with power from environmentally preferred sources. The right (tag) originates because a renewable power project may cost more to develop than the power will sell for. The project developer requires financing to build and lenders look at the market price to assess the financial risk of the project. Obviously, the developer (and the bank) would lose money if the power were simply sold into the market at prevailing prices. These prices do not reward producers for their environmental benefits. So, if the developer can find a market for those benefits, he can sell them for the difference between the market price and his actual costs. The green tag represents those benefits, and the price for the tag is a function of the difference between actual costs and the market price of the power.

Because power from the renewable project goes into the local power grid, there are no additional delivery costs as there would be from a direct purchase by a retail customer. Consequently, the green tag is independent of location. Conceptually, green tags will facilitate the development of renewable generation where it is most cost effective first. That way, the price of the green tags will be lower than otherwise. This should build a market for both green tags and renewable power developments. Although green tags are a new product, theory and reality appear to be converging, as green tag prices tend to be significantly lower than the premiums charged for the purchase and physical delivery of green power to customer locations.

7.2.8 Step Eight – Develop a Price and Supply Risk Management Plan

Deregulation of energy markets means energy prices will vary more than they have historically, even if average prices fall. The introduction of market mechanisms to transmission operation may require sacrifices in reliability in exchange for lower energy costs. No one can tell an agency or facility how these trends will affect it. More importantly, no one can tell how much volatility or lack of reliability a facility can handle. That has to come from the facility itself. That is one reason for collecting the information and conducting the analyses noted in Step One.

There are many ways to reduce the risk of price spikes including entering into long-term contracts with fixed prices. Generally, these contracts come at a premium to prevailing (and expected) market prices. Few organizations are willing to pay a premium over the market for price security; therefore, they fix prices (or “hedge” in industry terms) only a fraction of their total requirements. For example, fuel costs compose roughly 20% of airline operating costs. Nevertheless, airlines normally hedge 20 to 50% of fuel costs. Now that wholesale energy is traded as a commodity, there are a number of conventional financial instruments that can be used to hedge prices.

Unfortunately, government agencies rarely use these instruments. These instruments can, and should, be part of an overall energy management strategy, but their use must be governed by a risk-management strategy that is developed beforehand. This risk management strategy should describe the kinds of risk the agency or facility is trying to protect against and how far (the size of the hedge) it is willing to go to do so. This strategy will obviously depend on prevailing commodity price and supply levels, energy budgets and plans, and the flexibility the agency has to shift funds to the energy budget if prices suddenly rise.

Reliability risk is related to, but can be distinct from, price risk. Typically, the power system is highly reliable. Occasionally, situations may occur that interfere with reliable operation of the grid, such as a shortage of transmission capacity. Normally, this is short-lived. With the introduction of RTOs, consumers may be given the opportunity to reduce demand (accept lower reliability) in exchange for a billing credit or cash payment. In point of fact, this isn't an actual decrease in system reliability, but reliability could suffer if demand relief solutions are not adopted. Knowing how energy is being used puts a facility in a better position to offer up demand relief when and if the utility or RTO offers to pay for it.

7.2.9 Step Nine – Institutionalize Energy Management

Energy crises come and go. When they are here, the command management's attention can be used to focus resources on the energy management task. The rest of the time, energy management is sort of out of sight, out of mind, despite the fact that agencies and facilities continue to write larger checks for energy services than they probably could.

Deregulation of energy markets is likely to result in more frequent price and supply crises, leading to a non-productive energy management process. One way to overcome this crisis mentality is to institutionalize energy management in the organization by forming an Energy Management Team composed of major energy-using parts of the organization, people who perform critical activities that can be affected by unstable energy prices or supplies, and appropriate managers, including those with accountability for organizational performance, financial management, and so on. To be effective, the team needs to have a high-level leader/champion because energy management cuts across organizational boundaries. If energy or facility managers are unable to obtain sponsorship from highly placed managers, they should proceed without it. When the next energy crisis occurs, management will note their efforts and they can use that opportunity to recruit appropriate sponsors to the team.

The Energy Management Team should meet often enough to keep itself visible and vital, but not so often it appears ineffective. There is so much activity in this field, that meetings should be used to provide updates about institutional and regulatory changes and to discuss new technologies and energy products, just to keep them interesting. An educational mission can also be used to attract the interest of others in the organization, such as retail consumers trying to learn about deregulation of their own power bills.

7.2.10 Step Ten – Develop an Energy Management Plan and Strategy

Completing steps one through nine should result in a wealth of knowledge, information, expertise, and interest that needs to be captured so it is not lost or forgotten. One way to do this is to develop an Energy Management Plan and/or Strategy that can be used to guide decisions as they come up instead of having to revisit the entire energy management issue every time there is a question. There are a variety of models for energy plans and strategies; some of these are on government agency web sites.

Energy and facility managers usually have their hands full with their day-to-day work and don't have the time to put together an energy plan, especially not a plan that will need to be reviewed and approved by the stakeholders on the Energy Management Team! Fortunately, this task can be delegated to a professional or even to an enthusiastic intern or person on temporary assignment. The Plan itself should be relatively short but include plenty of appendices to back it up. For multi-tenant facilities, such as

military installations, federal buildings, and so on, it may be useful to have Plans for each tenant activity that form chapters in a single Energy Plan that ties all the parts together. There is no right or wrong way to put a Plan together, but it is more wrong than right not to have one.

8.0 How Does Deregulation Affect Me, the Federal Energy User?

Q. Why should I care about deregulation?

A. Knowing how this works can save you energy and money.

Q. How will I know when I am deregulated?

A. Deregulation has been preceded with the kind of critical reporting in the news media that accompanies any major news story, so when it happens it will be in the news. What is not so obvious is exactly how it will be implemented and how it may affect you. Partly this is because the rules governing deregulation lag behind legislative action to deregulate. Also, deregulation generally only applies to currently regulated utilities. Municipal utilities, electric cooperatives, and similar government-owned utilities are often excluded. Once deregulation has been adopted, the local utility or PUC often launches a public education campaign to let consumers know what is happening. Typically this is geared toward residential customers, but information is generally mailed to all customers. So, if deregulation is in the news, you should call your local utility and see if it affects your service.

A good source for details on the status of deregulation in your state is the FEMP Utility Restructuring website. <http://pnnl-utilityrestructuring.pnl.gov/index.htm>

Q. Deregulation sounds complicated. What happens if I don't do anything?

A. Deregulation is more complicated than traditional utility service has been in the past. However, most commercial customers have had to choose from an increasing menu of rate options recently, and deregulation is little more complicated than that (Figure 8.1). Federal agencies have a legal requirement to compete for goods and services when competition is available, and thus they will be required to shop around for the best deal on electrical supplies. To some extent, competition for electric supplies is simpler than for other services in that the local utility will have a standard tariff available for customers who choose not to choose. This provides a competitive benchmark against which alternatives can be compared. Ideally, alternative suppliers will be able to beat the utility "standard offer" tariff. However, during the transition to fully competitive markets, stranded costs and other costs may make that unlikely. As a result, the standard offer may be the lowest available rate.

Nevertheless, competition will be required to document this decision. Fortunately, other Federal agencies will be in the same boat as you, so they will provide competitive procurements that you can tie in to. The General Services Administration (GSA) and the U.S. Department of Defense's Defense Energy Service Center (DESC) both aggregate customers into buying pools. Other government institutions (like colleges, universities, and hospitals); and municipal and county governments may also be offering opportunities for consumers to join together in community choice aggregations. Federal agencies may be able to participate in these procurements. At a minimum all Federal customers should expect to be contacted by GSA and/or DESC to join an aggregation pool.

You can contact GSA or DESC directly through their websites:

<http://hydra.gsa.gov/pbs/xu/contracts1.htm>
<http://www.desc.dla.mil/PublicPages/a/electric/index.cfm>

Q. How Do I Procure Energy and Utility Services Under Deregulation?

A. Deregulation will proceed in two broad steps. Or as one regulator noted, deregulation is the first step across a two-step creek. The last step is the transition to fully competitive markets. This will only happen once stranded costs are paid off, usually 4 to 7 years after deregulation is launched. In the interim, stranded costs and other surcharges limit opportunities for consumers to reduce rates below present levels and for competitors to sell power at a profit. This actually simplifies the process for customers (albeit while it denies them the full benefits of competition). During the transition phase, competitors are basically competing against the standard offer rather than each customer's unique requirements.

As a result, competition boils down to a simple decision based on price (Figure 8.2). Other factors have to be included in the selection process, but price is the primary objective selection criteria. In order to provide competitive pricing information, bidders need to know as much as they can about the way you are presently using power. This includes the following information:

- total use (kWh) per month
- maximum use (peak demand in kW) per month
- use during peak demand periods (in kWh and kW)
- hourly loads (if available)
- meter numbers with service addresses and rate classes for each.

Ideally, the following additional information can be provided:

- service level voltage for each meter
- facilities served by each meter (it may be possible to combine multiple meters into one)
- work schedules that may affect energy use (particularly during peak periods)
- opportunities to shift or curtail energy-using activities during peak periods
- availability of on-site generation or energy storage devices (i.e., emergency generators, battery back-up systems, etc.)
- energy-saving opportunities
- planned or prospective changes in energy equipment (i.e., chillers) or facilities (downsizing, expansions, retrofits).

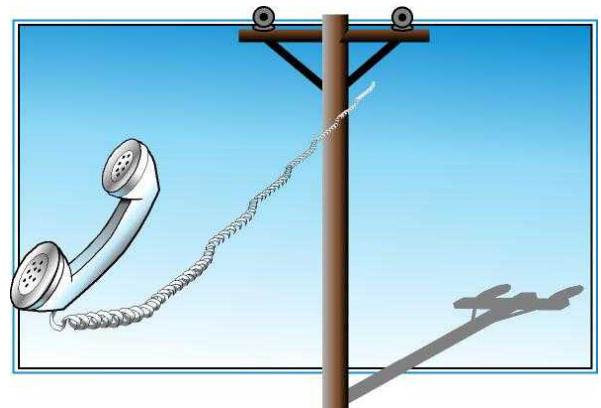


Figure 8.1. As with telephone deregulation, your local utility company will continue to maintain power distribution and wiring to your house. You will be able to pick your power supplier (just as you now have a choice in picking your long-distance phone service provider).

These are intimidating lists. Fortunately, most of this information is readily available from utility records for the past year, energy audits, and energy management reports and facility plans. However, it is time-

consuming to pull this information together and often certain records, such as utility bills, can only be compiled with the written consent of the customer named on the utility bill. In other words, if GSA pays the utility bill for a State Department facility, GSA must request release of billing records to the State department. GSA posts some of this information on an intranet site.

Once the appropriate information is available, it can be provided to potential bidders in a request for proposals (RFP). Generally, this information is provided for more than one meter or site. As a result, the database itself is quite large. Consequently most Federal energy procurements simply post the information on the Internet rather than providing paper copies (See DESC's web site as an example.) The RFP should specify the term of any contract. Federal energy commodity procurements are limited to 5-year terms. Utility contracts are limited to 10-year terms. The RFP needs to be consistent with these limits and the customer's needs. For a variety of reasons, most Federal electricity procurements are for short terms with an emphasis on commodity prices. Once appropriate specifications are developed, the RFP can be issued following regular procurement procedures.

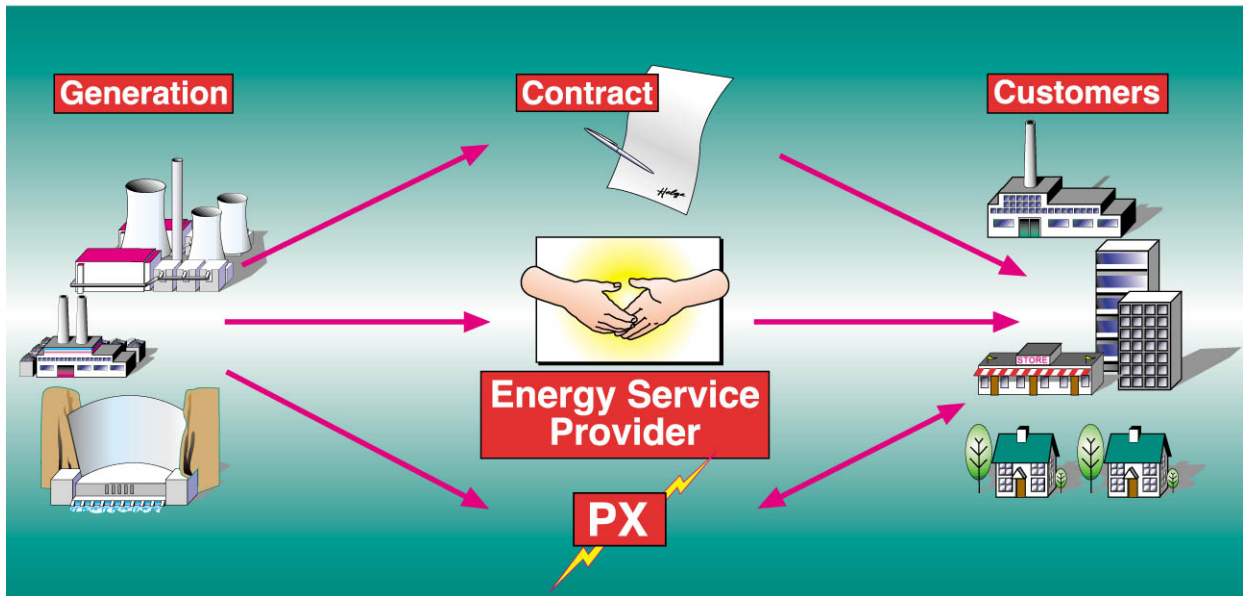


Figure 8.2. Buying power in a deregulated market. Customers have several options when buying power in a deregulated market, including establishing a long-term contract with an energy service provider, joining a pool of customers such as the pools set up by GSA and DESC, or continuing with their current utility provider.

Q. Where Can I Turn for Help?

A. There are good reasons to seek help. Specialists in energy markets are available both for hire and through FEMP to assist agencies with energy procurement decisions. However, the most common approach to date has been for Federal agencies to join a load aggregation under the auspices of GSA or DESC. GSA manages power procurements through its regional office network. DESC manages DOD power procurements centrally, from the Defense Logistics office at Fort Belvoir, Virginia. Both GSA and

DESC also procure natural gas supplies for Federal agencies. The services of the GSA and DESC programs are offered to any Federal agency and can also be used by other governmental units, such as state and local governments and school districts. Similarly, Federal agencies may be able to participate in aggregate purchasing pools with other non-Federal agencies, as long as the Federally required terms are included in the contract. Sometimes local governments receive more competitive price bids than Federal agencies, so it is worth working with these entities to evaluate competition in the marketplace.

Q. What will happen if I change power suppliers?

A. Changing power suppliers is primarily a financial transaction. The power supply system is largely unaffected. Your new power supplier will produce the amount of power required to meet your needs and arrange to deliver it to your meter through the bulk power grid (hence the need for potential suppliers to provide evidence they are capable of delivering power to the grid and through the local distribution system to your meter). The new supplier will most likely read your power meter and figure your power bill. Depending on the state, they may bill you directly. You may receive another bill from the local utility for delivery services as well. In some states, the local utility will continue to read the meter and bill for both power and delivery services. Often the new power supplier will need to replace your existing power meter with a new one. This may be required because the local utility no longer bills you as a customer or because the new power provider requires a different kind of meter for billing purposes. This is particularly true if you are on a time-of-use or other form of interval metering (rather than simple kWh metering). If your meter has to be replaced, the costs will be reflected in your power price (either as a meter charge or as a somewhat lower discount or higher power price). As a rule of thumb, it costs about \$1,000 to replace an interval meter. This cost has to be recovered from profits, hence the reduced savings.

Q. What will happen if my power supplier fails to deliver?

A. The failure of a power supplier has two consequences, one to the power system and one to the power purchaser. The power system is designed to absorb the loss of a significant fraction of generation. It does so by relying on generating reserves and, if these are inadequate, emergency curtailment provisions. If a very large power supplier fails to honor its generating obligations, the bulk power market may not have adequate reserves. That could precipitate emergency curtailment actions, and if these fail, brownouts and blackouts. This happened in the mid-west wholesale market in 1998 and in California in 2001.

Although the power system has mechanisms to absorb the loss of a major supplier, the loss can ripple through the system in the form of somewhat higher costs for all customers. Nevertheless, the customers of that supplier will bear the full brunt of costs for making the system whole. In effect, the power system turns to alternative suppliers for make-up power to meet your needs. This power is likely to be quite expensive. The parties that provide the power will turn to your supplier for payment. If they are unable to recover their costs, they may sue your supplier, and potentially, you. Accordingly, most power contracts include performance and “hold harmless” clauses. Nevertheless, the default of your supplier will leave you without a long-term supply contract. Your service will continue but under terms that will not be identical to those that were in your contract.

Q. What about my current utility-financed demand-side management (DSM) projects?

A. Many utilities offer energy-efficiency programs to Federal agencies. The agencies are obligated to repay the utilities for the cost of these programs, unless they were offered free of charge, such as energy audits. These obligations are in the form of a contract that remains irrespective of the source of power supply. Some contracts allowed for repayment out of bill savings and, in most cases, they allowed for cash payments if bills fell significantly or if the customer relocated or curtailed service. Accordingly, there is probably a provision in any outstanding utility DSM contract for a payoff. Consequently, you are still obligated to pay off any utility-financed DSM project. When you change power suppliers, the local utility may not have a mechanism to repay outstanding debts from bill savings. Consequently, you may have to write a separate check to repay the DSM program costs.

Your local utility remains your distribution utility. As a result, you are still able to complete any utility-sponsored DSM projects currently being planned or underway. Similarly, you are able to participate if the utility continues to offer energy audits and efficiency or renewable energy programs after deregulation. You are also able to take advantage of similar services that may be offered by your new power provider. Prior to deregulation, you were able to take advantage of utility-sponsored programs without competition. This is not necessarily the case after deregulation, especially if you have essentially two utilities serving you (one providing power, the other providing delivery services). You should consult your local utility and power supplier to determine what, if any, efficiency programs they may offer. In addition, you should consult with your contracting and legal staff to determine if you can tap this capability without having to release a solicitation for this service. Additional guidance and resources are available from FEMP, GSA, and DESC.

Q. What about competition in metering and billing?

A. Some states allow customers to select a new agent for metering and billing. Typically, this is the new power provider. However, it may be a third party not connected with either the power supplier or delivery company.

New energy providers often require the use of a specific meter, which they normally install and maintain. Other than requiring periodic testing by an objective firm, customers should not care about the brand of meter installed. Instead, they should be concerned about the kind of information the meter produces and retaining access to that information if a new provider is selected at a later date. As competitive markets mature, it is possible that metering and billing will be outsourced to specialized firms. If that comes to pass it may be possible to make a long-term investment in a metering system without jeopardizing the selection of suppliers.

Q. What is real-time pricing and why does it require new meters?

A. Some utilities have offered larger customers some form of time-of-use prices for years. Time-of-use rates better reflect the true cost of producing, transmitting, and distributing power as it varies during the day and year.

After deregulation the risk of price volatility that was absorbed by the utility in fixed rates is passed on to customers in variable prices. Because prices vary on an hourly basis, it is essential to monitor power use on an hourly basis, hence the need for a meter that records power use hourly, or even more frequently, e.g., a real-time meter. Power vendors need to know how much power to buy on an hourly basis to avoid purchasing too much high-cost power. As a result, they may require large customers to install real-time meters that can be read remotely, such as over phone lines. This allows power vendors and users to monitor power use in real time.

Q. What should I do to prepare for deregulation?

A. Your first step should be to get informed about deregulation and the status of deregulation in your state. Reading this primer and checking the FEMP website are good places to start. The second step should be to collect energy-use data, including quantity, price, rate schedule, rate design, number of meters and their locations, and associated utility accounts. These steps should be taken for every facility in every state, irrespective of the status of deregulation. If your facility is in a deregulated state, determine who is responsible for energy procurement and see if they have taken steps to compete the service. If deregulation is just beginning, the regional GSA office and DESC will soon be soliciting Federal agencies to join in a power buying pool. Your energy manager needs to determine if you would be better off competing the facility load with, or separate from, GSA or DESC. Some facilities are very attractive customers for energy marketers on a stand-alone basis and they may obtain a larger discount than could be arranged through GSA or DESC. However, the cost of undertaking a competitive procurement is considerable and may offset savings on a stand-alone basis. Moreover, some facilities may have no choice but to have GSA or DESC procure energy for them.

Q. What about so-called “green” power?

A. One of the advantages of deregulation is that competing suppliers may offer more choices of products. Green power is one such product. Typically, green power is produced from sources that have comparatively low environmental impacts; consequently, it sometimes costs more. Green power is not necessarily the same as power from renewable resources. For example, some firms consider power to be “green” if it comes from large hydropower projects (although these may damage wetlands and reduce fish populations) or nuclear plants (which may release fewer air emissions but can introduce other environmental hazards). Producers of green power and some states have stepped in to certify products as “green” based on standard definitions that ensure the label is only used for environmentally beneficial products. GSA and DESC can request bids for green products that fit the environmentally beneficial guidelines used by the government. Further standards and clarification of what constitutes green power and how to procure it will be forthcoming as a result of Executive Order 13123. FEMP, GSA, and DESC will provide Federal agencies with information as deregulation proceeds.

Glossary

A

Access Charge or Wires Charge

A fee charged to an electricity supplier, gas supplier, or long-distance telephone provider (or to the customers of such companies) for access to a utility company's distribution system (the pipes or wires through which the utility supply moves, or the telephone lines owned by the local telephone company). It is a charge for the right to use another company's equipment and systems. The fee is generally set by state regulators at cost-based rates. For example, California electricity customers can purchase electricity from a power supplier of their choice. This supplier must arrange to transport the power over the local utility's wires. To do so, they must pay an access charge (also called a wires charge). In most deregulated states, the power supplier can bundle this charge into a single consumer bill. In a few states the consumer pays the access charge in a bill that is separate from the power bill. *See also Wires Charge.*

Affiliate

A company that has the same owner as another company. For example, a company may have a separate company in the power plant development business. The parent company owns both this power developer and the local utility. When regulated utilities purchase or form subsidiaries they have to get approval from regulators. Another way to own several different companies is for a utility to form a holding company. Holding companies facilitate ownership of more affiliates, but are regulated at the Federal (rather than state) level by the Securities and Exchange Commission. They are also restricted under the Public Utility Holding Company Act of 1935 (PUHCA).

Aggregator

An entity that brings customers together to buy electricity in bulk, in order to increase customers' buying power. Aggregators can serve homes, businesses, or entire communities. They facilitate the purchase of power but are not the sellers. Retailers, customers, and brokers may also act as aggregators. It is assumed that the purchase of a large quantity of a commodity will attract more favorable bids than small ones. Commodity price savings from aggregation have been small thus far. However, aggregation results in significant savings in procurement costs, as only one agent is needed to execute a procurement on behalf of all participants.

A public aggregator is a unique form, established by a city, town, or county to purchase electricity in bulk for its citizens in order to increase their buying power. Public aggregators resemble consumer-owned utilities in that they are formed to reduce costs for consumers. However, aggregators are not utilities and do not distribute power to end users.

Allocation

Generation may be divided up, or allocated, among purchasers for a variety of reasons, such as to link costs, risks, and benefits for projects developed by multiple sponsors. Power projects developed with public funds most commonly allocate the output (and cost recovery) to specific beneficiaries. For example, power from the Hoover Dam, which was built with Federal funds, is allocated to specific Western utilities that are customer-managed and serve predominately rural areas.

Alternative Energy Supplier

A supplier of energy that is not the company providing distribution and transmission services to the customer. Alternative suppliers may be brokers (agents that are middlemen between energy producers and consumers) or marketers (agents that own the energy they are selling to consumers). Aggregators are not alternative suppliers as they only aggregate customer demand, not supply.

Ancillary Services

The electric power system is dynamic. It responds to electricity use by customers. As a result it must be able to adapt rapidly to changes in use. Deregulation of wholesale generation and transmission markets resulted in unbundling of individual elements of power supply into discrete services that are ancillary to, but necessary for, a reliable power supply, so-called “ancillary services.” These include things such as generating reserves that are not specifically purchased by retail power users, but are included in the retail price of power as they contribute to power system reliability. Ancillary services are critical components of wholesale power trades, but are assumed to be part of the purchase in retail power transactions. Wholesale power suppliers have to make arrangements for ancillary services as part of the process of conducting transactions with retail consumers. Retail customers should clarify that this is the case, just to be sure. Similarly, ancillary services are not the same as the value-added retail services that are often included with retail power sales, such as free energy audits.

B

Back-Up Service

Customers with their own resources may have to provide resources in reserve to ensure against a failure of the primary resource. Typically, this is only required of a customer with on site generating equipment. These customers may require back-up supplies from the local utility. Without this back-up option, the customer would either have to maintain redundant generation on-site or risk power outages if on-site equipment were unavailable or inadequate to meet on-site power needs.

Balancing

Power demand and supply must match on a moment-to-moment basis. Unfortunately, it is impossible to accurately predict demand that frequently. As a result, a portion of generation capacity is set aside specifically to fill-in any gaps to make sure the system stays in balance. A key part of system operation is for suppliers to provide accurate estimates of production, hour-by-hour as well. Sometimes they err. When they do, generation has to come from someone else

to make up the shortfall. This also comes from generation used for balancing. When generators err in their estimates, they have to pay for the costs of balancing. These charges can add up for generators that are consistently wrong. Unfortunately, estimate of the power from intermittent renewable resources, like wind and solar, are often wrong and balancing costs may make them uneconomic.

Base Load

The minimum energy level a company must provide to its customers on a constant basis. The exact amount varies each day because aggregate customer loads vary from day to day and month to month. For example the base load for low electricity use in the spring and fall months is lower than in the winter and summer. Consumer loads mirror utility generating requirements. As a result, the phrase “base load” also is used to characterize customer needs. Specifically, power suppliers are interested in each customer’s base loads in order to identify the minimum quantity of power to sell. Both generators and power suppliers also characterize loads in terms of peak load, the maximum amount of power needed.

Base Load Plants

Plants that run at full capacity year round to meet a utility’s base load are called base-load plants. For base load plants, utilities select plants with the lowest generating costs, construction, and operating costs. Traditionally, base-load plants were fueled with coal purchased in very large volumes on long-term contracts.

Bid-Ask Negotiations. See Commodity Market.

Bid-Offer Auctions. See Commodity Market.

Bid Stack. See Dutch Auction.

Bright Line

A distinction the industry is trying to draw between distribution and transmission. Such a line is needed to clarify FERC and state jurisdiction over power line regulation and rates. FERC normally has jurisdiction over high-voltage (750, 500, 230, and 115 volt) transmission lines while the states have jurisdiction over low-voltage (69, 34, and 13 kilovolt) distribution lines.

British Thermal Unit (BTU)

This is the standard unit for measuring quantity of heat energy, such as the heat content of fuel. One BTU equals the amount of heat necessary to raise the temperature of one pound of water by one degree Fahrenheit. There are 1.03 million BTUs in 1 Mcf (an Mcf is a unit of volume meaning 1,000 cubic feet). There are 3,412 BTUs in 1 kilowatt hour.

Broker

A person or group that arranges for the purchase and sale of electricity, transmission, and other services between buyers and sellers, but does not take title to the power in the transaction. Energy brokers act just like a real estate or insurance broker. They earn a commission on the sale of energy, not a profit on the mark-up. This contrasts with marketers, who own title to the energy they are selling and make a profit based on selling the energy for more than they paid.

Bulk Power Market or Wholesale Power Market

The bulk power system consists of the generation and transmission system and the wholesale financial transactions associated with power and transmission transfers on the system. It includes wholesale purchases and sales of electricity, transmission reservations to wheel that power, and potential interactions with power pools and independent system operators (ISOs). Access to the bulk power market is reserved for wholesalers, including power producers, power retailers, and a few very large direct-use customers. Some Federal agencies have access to the bulk power market at selected sites. *See also Grid, Transmission System.*

Bundled Service

Before deregulation, customers received electric generation, transmission, distribution, and related support functions as a combined service. After deregulation the same services are provided, but each service is individually priced (unbundled) and may be provided by a choice of suppliers. Although all component services are unbundled in rates, only a few are presently subject to choice. The most common services available for competition are power supply, value-added services like energy efficiency, and metering and billing.

Buy-Sell Agreements. See Net Metering.

C

Capacity

The physical capability of a pipeline, power plant, or other facility. In the electric industry, generating capacity is measured in terms of kilowatts (1,000 watts) or Megawatts (1,000 kilowatts) and transmission capacity is measured in kilo-volt-amperes (kva). In general conversation, capacity is used to indicate a maximum; for example “The capacity of the generating plant is 500 Megawatts (MW).” The adjective maximum is assumed.

Capacity Market

Power demand varies from day-to-day and season-to-season. The power system has to have enough capacity in it to provide for the maximum demand for both power and delivery. Since this capacity is only used during peak periods, it may sit idle the rest of the time. Nevertheless, it has to be paid for. Unfortunately, simple kWh billing doesn't reflect the fact that some generation, transmission, and distribution capacity is just sitting in reserve for peak demand periods. Utilities try to recover those costs through a “demand charge.” Prior to deregulation, retail customers paid the local utility for energy (kWh) and demand (kW) based on the costs of the utility's generation. Now that wholesale markets are deregulated, the utility may purchase capacity, as a separate commodity, from a competitive market that trades just capacity (or access to stand-by generation).

Capital Investments or Utility Assets

These include generating plants, transmission and distribution systems, and other infrastructure such as office buildings. Utilities raise capital for investments by borrowing from lenders and issuing stock to investors. Investor-owned utilities earn a rate-of-return for capital they invest in utility facilities. These assets are called the rate base. Utilities do not earn a rate-of-return on normal expenses, such as salaries, maintenance, and fuel.

Captive Customer

A customer who, because of remote location or lack of competing providers, has no alternative to purchasing service from his or her local utility company.

Cherry-Picking

The practice of pursuing desirable customers and ignoring less desirable customers. The term is commonly used in energy markets to describe a power supplier's tactic of trying to get the business of the largest users while ignoring small ones. One way small customers can thwart this strategy is to aggregate with other small customers so they resemble a large customer.

Cogenerator

A facility that simultaneously produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. Using the "waste" heat instead of burning more fuel increases the thermal efficiency of cogeneration projects. As a result, cogeneration is environmentally preferable. Because the use of the waste heat is closely tied to a specific application, the cogeneration plant is almost always located at the customer's site. The demand for waste heat at that site typically drives the design, and size, of the cogeneration plant. The plant may not be able to provide all of the power needed at the site. Although cogeneration plants may be subject to siting and emissions regulations, all customers have the right to install cogeneration facilities. In other words, you are not required to prove a need for the power and local utilities cannot stop you from installing cogeneration. This is not the case with some other kinds of onsite power plants.

Collar. See Price Ceiling.

Combination Utility

Generally, this refers to a utility that provides both electricity and natural gas to retail consumers. Many electric utilities are merging with retail gas utilities to become retail-focused combined utilities. This trend is called convergence.

Combined-Cycle Combustion Turbines. See Gas Turbines.

Combustion Turbines. See Gas Turbines.

Commerce Commission. See Public Utility Commission.

Competition

A market structure in which two or more companies compete for customers' business. To be effective, competition requires that no company be able to dominate the market. This ability is called market power and is critically reviewed during deregulation and merger proceedings involving present retail utilities. Effective competition should also allow choice on the basis of price without the distorting effects of stranded costs and other, non-power related, fees and surcharges.

Competitive Power Supplier

A competitive power supplier (also known as an electricity supplier, power producer, power generator, power seller, power marketer, or power broker) is a company, person, or organization that sells electricity. Some suppliers generate and sell their own power, while others buy it and then resell it. In any case, the electricity sold by a competitive power supplier is delivered to your home by your local distribution company. How much a competitive power supplier charges for electricity is set by the individual supplier. All customers pay the local distribution company the same rates for local delivery.

Competitive Retail Electric Service

This refers to a situation in which consumers purchase power from competing electricity-suppliers.

Conservation

Reducing a customer's use of water, gas, and electricity to decrease the need to produce and/or transport these commodities. Conservation reduces consumer utility costs and environmental impacts from utility commodity development and distribution.

Congestion

When transmission is inadequate to meet local demand it is called congestion. Power grids were originally designed to provide adequate transmission capacity for local generation plants to provide power to customers located in the vicinity of the plant. In competitive power markets the demand for low-cost power increases and low-cost power may be sent great distances to reach consumers. The existing transmission system cannot accommodate all of that low-cost power flowing to a few high-volume markets -- the result is congestion. Congestion is relieved by operating higher-cost generating plants to run near the high-demand areas. This works because when local generation is used, transmission isn't needed, so there is less congestion on the transmission grid. The costs associated with congestion relief are passed on to consumers, often only to those on-line during the congested period. Congestion is managed by the utility control center in the area where transmission is congested. In the transition to competitive markets congestion is being managed by ISOs.

Contract Terms

Contract terms are the agreements between a competitive power supplier and a consumer specifying the length of service and whether penalties exist for early termination. Consumer expectations of power supply and reliability were protected by state regulators prior to deregulation. After deregulation, some (but not all) of these expectations may be subject to negotiation. For example, the power supplier may require the customer to reduce loads when power supplies are very expensive or in short supply.

Control Center. See Grid.

Cooperative (Co-op) Utility

A type of utility in which the customers are also the owners. Co-ops are not-for-profit institutions, which reduces costs to end users. Co-ops are managed by a Board of Directors elected by member customers. Co-ops are common in rural areas that are expensive to serve because of the long distances between users. The Federal government contributes in various ways to rural cooperatives to reduce costs to individual owners and users through the Rural Utility Services agency.

Core Market

This refers to utility customers who do not have the option to choose among competing utility suppliers and who are therefore captive to a single supplier. Customers who comprise a utility's core market are also referred to as captive customers. The term core customer comes from the natural gas industry. Natural gas utilities divide customers into two types, core and non-core. Core customer refers to a retail natural gas customer that is too small to tap into the wholesale gas market; the local gas distribution company is obligated to serve this customer. In contrast, non-core customers have sufficient size, expertise, and buying power to negotiate for gas supplies in the wholesale market. The local gas utility is not obligated to provide gas for non-core customers, especially if it interferes with supplies for core customers. Natural gas demand is greatest in the winter when residential heating demand is high. If gas supplies cannot be obtained to serve all customers during these periods, the gas company can curtail deliveries to non-core customers. Natural gas markets were deregulated for large, or non-core, customers over 10 years ago. These large customers can now seek out gas supplies directly from the wholesale market.

Electric utilities do not have a similar distinction between core and non-core classifications for customers. Large retail electricity customers are not allowed to tap directly into wholesale markets. Before deregulation, essentially all customers were core customers. After deregulation, all customers are essentially noncore customers, except those that are "captive" because of remote location or lack of local competing providers.

Cost-of-Service (COS) Pricing

This is a method of allocating the costs of providing service to individual customers. It contrasts with value-of-service pricing. Value-of-service pricing is used in competitive markets, where sellers price items at "what the market will bear." Price regulation was imposed on regulated utilities to ensure that utilities are only priced at cost, not at what the market will bear. The assumption was that competitive pricing could be so high as to restrict access to utilities to the

wealthy. As a result, cost-of-service pricing was used to set utility rates. Under COS regulation, utilities are allowed to recover reasonable costs plus a rate of return on investment. The resulting rate is expected to be less than what it would be with competitive suppliers. Because the costs to serve customers varies, COS attempts to correlate utility costs and revenues with the service that is provided to each customer, typically as one customer of a class of customers. As a result, customers in different classes are charged different rates.

Cramming

Adding services and charges to customer bills without the customer's knowledge or consent. Cramming has been a problem with telephone deregulation and steps are being taken by states to prevent it under energy deregulation.

Customer

There are two utility perspectives on what constitutes a customer. The historic view is based on the energy meter: one meter equals one customer; i.e., a firm with 10 meters would be viewed as 10 customers instead of one bill payer. This view is based on cost-of-service rate making, where utility charges are based on what it costs to serve each meter. This perspective prevents utilities from offering customers with multiple meters a quantity discount, because that would be discriminatory and violate cost-of-service rate-making principles. The advent of competition in the utility industry has encouraged utilities to view each customer as one bill payer regardless of the number of meters they have and to curry favor with customers on the basis of total consumption rather than use per meter. This is the more traditional marketing definition of customer.

Customer Charge

The first component, the “customer charge” is designed to cover customer service costs, including metering, billing, and providing marketing and customer service facilities. The customer charge” varies for each customer class and is generally a flat fee for all customers in the class.

Customer Choice

The ability of consumers to choose their suppliers of natural gas or electricity without respect to utility service area.

Customer Class

Typically, utilities divide customers into three classes (residential, commercial and industrial) for rate-setting purposes. It is not unusual for utilities to further group customers with similar service requirements into subclasses (e.g., residential space-heating customers). Commercial and industrial customers are often called general service customers (small and large respectively). Customers are divided into classes based on use characteristics such as service voltage, maximum demand, average use, and total bill. Many states require special treatment for residential and farm customers based on their comparatively low consumption levels. In those cases, the residential and farm classification is based on customer type rather than other characteristics, even when the customer is a large energy user. With this exception, customers are generally classified based on energy use at each individual meter. As a result, a single firm with multiple meters may have different rates for each one. *See also Cost of Service.*

Cycling

The process of starting up and shutting down a plant. The costs of cycling varies depending on the plant type.

D

Daily Peak

The maximum amount of energy or service demanded in one day from a company or utility service. *See also Peak Demand, Capacity, and Base Load.*

Day-Ahead Market. See Power Exchange.

Declining Block Rate

A declining block rate provides consumers with an incentive to consume more power by reducing the cost per kWh as total use increases. Both declining block and inverted rates can have multiple blocks. The simplest form consists of two blocks. However, three or four blocks, each with a different kWh charge, are not unusual. This kind of rate design requires regulation; it would be impossible to implement in an open and competitive market. *See also inverted rate.*

Default Service

Prior to deregulation, the local utility was required by law or regulation to provide service to **all** customers in its service area. (This principle is also referred to as universal service.) Utilities were even required to provide service to customers who were costly to serve due to their location or uneconomical to serve because of poor credit. After deregulation, competitive suppliers are expected to shun these customers. As a result, many state deregulation plans include provisions for default service to provide customers with a continuous power supply through their distribution company when, for whatever reason, they are not receiving power through the standard offer service, an aggregator, or a competitive power supplier. Where default service is available, customers are eligible to receive default service at any time and may stay with this service indefinitely, though it may not be the most cost-effective means of buying power. Not all states have provisions for default service.

Delivery Service Charges. See Distribution Charge.

Demand

A measure of customer or system load requirements over a measured period of time. Demand is used to establish requirements for both generating and transmission capacity. In economic terms, this is the inverse relationship between the price of a good and the quantity of the good that is demanded by consumers (high prices drive down demand and vice versa). Demand is for consumers what capacity or base load is for suppliers. *See also Base Load, Capacity, Daily Peak, Load, and Peak Demand.*

Demand Charge

This is the amount charged to a customer (or customer class) to reflect that customer's use of a utility during a specified time interval. In cost-of-service analysis, the demand charge is usually based on the fixed costs associated with serving customers. It is levied based on the maximum demand over the interval and is used to pro rate the cost of production and transmission capacity equitably across all customers. For example, if it costs \$10 to have a kW of generating capacity available, customers would be charged \$10 for each kW of demand (peak consumption) as a demand charge.

Demand Meter

Peak power use is monitored with a demand meter, a kilowatt-hour meter with a separate demand register. Peak demand as registered by the demand meter is billed as a separate line item on the power bill. Demand meters are more complex and expensive than kWh meters. Demand metering functions are built into time-of-use and real-time meters. In fact, time-of-use and real-time meters are often installed primarily for demand, rather than kWh, metering. Similarly, demand charges may also vary on a time-of-use or real-time basis.

Demand Register. See Demand Meter.

Demand-Side Management (DSM)

Demand-side management refers to a range of activities that change the way energy is used in terms of time of day and quantity. The goal of DSM is to reduce demand; from the supplier's point of view, this either reduces the cost of service or the profitability of service. Customers implement DSM measures to reduce utility costs, although the DSM measure may not reduce utility use, en toto. A demand-side management program is the planning, implementation, and monitoring of electric activities that are designed to influence customers' use of electricity in ways that will produce desired changes in a supplier's load shape (i.e., changes in the time pattern and magnitude of a supplier's load). According to the Electric Power Research Institute (EPRI), there are six DSM objectives: load reduction (conservation), load shifting, peak-clipping, valley-filling, load growth, and flexible load shape. Utility programs falling under the umbrella of DSM include load management (direct load control), energy efficiency, energy storage, and innovative rates. DSM programs can be implemented through energy audits, fuel switching, rates, loans, or incentive payments. DSM objectives can also be accomplished through non-utility programs that introduce higher efficiency standards or transform markets by introducing more efficient products. *See also Efficiency Services and Load Management.*

Deregulation

The process of removing price regulations on price regulated utilities. In general, only price regulations are removed, all other aspects remain regulated. The term deregulation is used outside the United States to refer to the sale of government-owned or controlled assets to private-sector operators. U.S. based utilities are not government owned to start with so there is no need to go through this phase of deregulation. Under deregulation, generation is separated from transmission and distribution. Local utilities are still required to provide transmission and distribution, which remains regulated, but the generation of power has been deregulated, rates are no longer fixed and power generators compete for customers. Deregulation and industry restructuring are often used interchangeably; however, it is useful to draw a distinction between

the two. Deregulation is what regulators do to utilities. Restructuring is the industry-driven adaptation to deregulation, including preparing for competition, seeking new products and markets, and merging with other firms. Restructuring is what the industry does to itself. *See also Restructuring.*

Derivatives

Products such as options and futures offered by financial markets to buyers and sellers. Because they derive their value from trades in markets in which a person does not need to either produce or use the item they trade, they are called derivatives. Participants in these commodity markets are called speculators, although trader is a more accurate term. Unfortunately, derivatives have gotten a bad name because of the way some people used public funds to speculate. A typical use of a derivative is to “hedge”, or fix, the price of a commodity that is expected to vary in the market. For example, roughly 30% of the operating cost of an airline is jet fuel. If jet fuel costs doubled in the market, the airlines would need to increase ticket prices to compensate. That would discourage air travel. As a result, airlines typically buy a derivative (an option or future) that lets them buy fuel at a fixed price in the future. If fuel costs are higher than that price, the airline doesn’t use the derivative to buy the fuel. Instead, it sells it for the difference between the price it purchased the derivative for (the “option” price) and the current market, or “strike” price. Now it has the extra money it needs to pay the higher fuel costs, so it doesn’t have to raise ticket prices. If, on the other hand, fuel prices fell below the option price, the airline would have spent money on a derivative that it didn’t need. This extra expense will be tacked on to ticket prices also. Accordingly, choosing an hedging strategy (how many derivatives to purchase and when) is a major business decision. People usually get into trouble when they don’t have a good hedging strategy (called a “risk management strategy”). Often, they buy more derivatives than the need to hedge their risk. Then, when the market moves against them, they have losses that they cannot justify based on a sound analysis of risk.

Direct Access

The ability of a retail customer to purchase electricity directly from a competitive power market and then have the local distribution company deliver the power over its transmission and distribution system for a fee. (Also known as customer choice, deregulation, retail wheeling, or open access). *See also Wheeling, Open Access, and Transmission Charges.*

Disclosure

A requirement that competitors in an electric market provide generation source information, environmental impacts, and other information on price and conditions of service. Some states have adopted rules that require suppliers to make uniform disclosures to consumers.

Disclosure label

A disclosure label is a standard format of information required by state regulators detailing a competitive power supplier's prices, the terms of its contract with a customer, the types of power sources used, its air emissions, and its labor practices. The same format is to be used by every supplier and distribution company to make it easier to compare the various offers. The format of the label is dictated by regulators. However, not all states have disclosure requirements and virtually none of the states use the same standards or use the same label format.

Dispatch

To start and run a plant. *See also Production Costs.*

Distributed Energy Resources. See Distributed Generation.

Distributed Generation

Generation sources (also known as distributed energy resources) that are disbursed throughout the grid and located at individual customers' sites. This is in contrast to traditional sources of generation, typically a few large generating plants located centrally, often at some distance from users. Advances in fuel cells and other generating technologies are making the concept of distributed generation increasingly economical for end users. Another example of distributed generation is a large industrial facility that uses thermal power from process heat to generate both electricity and thermal energy. Individual power generators can be deployed, on-site, to supplement or replace power from the utility grid. Distributed generation devices can also replace existing emergency generators and universal power supply (UPS) systems for critical medical and computer needs.

Distribution

Electricity is generated and transported at higher voltages than it is used by all but the largest industrial customers. It is more efficient to transmit electricity at higher voltages. As a result, electricity is not "stepped down" to consumer voltage levels until it is close to the point of use, namely individual homes and businesses. The delivery of electricity to a retail customer's home or business through these low-voltage lines is called distribution. Transmission is the transportation of electricity at very high voltage levels, generally for long distances.

Distribution Charges or Delivery Service Charges

Part of the basic service charges on every customer's electric or gas bill for delivering electricity or natural gas from the distribution company to a customer's home or business. This charge will vary according to how much it costs to serve a customer in each class. Generally, distribution charges are based on how much energy is used. Historically, larger customers paid for distribution costs through a demand charge, whereas smaller customers paid a simple kWh fee. This may change after deregulation.

Distribution Company (or Disco)

The term "utility" has lost some of its meaning in the face of deregulation. Formerly, utilities were assumed to be firms that provided power to consumers. After deregulation many states prohibited formerly integrated utilities from selling power to customers. Instead, they were restricted to simply transmitting or wheeling power between power sellers and retail power buyers/customers. To acknowledge this change, the phrase "distribution company" was introduced to identify the former electric utility company as the company that delivers electricity to your home or business. The distribution company will continue to maintain local wires and poles, and restore your power in the event of an outage. It will continue to read your meter, but it may not be the company that either prepares your bill or collects payment for power use and delivery.

Divestiture

Divestiture occurs when a utility company sells one of its services or functions to a new company. Divestiture is often used by regulators as a means to mitigate an incumbent utility's market power. In this case, the incumbent utility sells off some or all of its generating plants so that it no longer has market power. Market power is the ability to set prices in the market, thereby frustrating competition among suppliers.

Dutch Auction

The bidding method used in auctions to set prices. The California Power Exchange (PX) uses a Dutch auction to set prices for power and ancillary services. All suppliers bid into the auction at the same time, but none knows the others' bids. Bids are put in a bid stack, lowest to highest, by the PX. Supplier bids are accepted on a lowest-cost-first basis up to the point that sufficient power has been purchased to satisfy demand. Bids above this point are rejected. The last bid accepted that satisfies demand sets the marginal cost of power or market clearing price (MCP) for power for the bid period, usually a one-hour period. (The market clearing price is also known as the market price, the marginal price, or the market marginal price.) Under a Dutch auction, the last accepted bid establishes the price paid to all vendors, regardless of their actual bid. In other words, if the last amount of energy needed to satisfy total demand was at a price of 4 cents/kWh, all winning supply bidders would be paid 4 cents/kWh even if the bids they submitted were less than 4 cents. Bids above 4 cents would be rejected and those vendors would receive no payment. The use of the term Dutch auction in California is at odds with some other definitions.

E

Efficiency Programs or Services

Efficiency programs are a specific variety of DSM services aimed at reducing a customer's total energy use without affecting the delivered energy service. Programs could include installing insulation and weather stripping and converting to compact fluorescent light bulbs. These services may be offered by energy-efficiency companies, distribution companies, aggregators, and competitive power suppliers. Although some of the companies offering efficiency programs may charge a higher rate for electricity, it is possible that by reducing your energy use, you could save more money than if you bought electricity at a lower rate without these programs. Energy efficiency programs also help reduce the harmful environmental impacts of power production and use. They also help Federal agencies meet the efficiency goals of Executive Order 12123.

Electric Cooperative

A member-owned electric utility company that generates or purchases wholesale power, arranges the transmission of that power, and distributes the power to serve the demand of rural retail customers on a non-profit basis. Rural electric cooperatives were created to bring electricity to rural areas that were not being served by for-profit utilities because of the high cost and low customer density. *See also Cooperative and Investor-Owned Utility.*

Electric Generation

Electricity can be generated through a wide variety of processes, although far and away the most common is by the rotation of a generator shaft, or rotor, through opposing magnetic fields. Shaft rotation induces the flow of electricity in the generator. An external energy source is required to rotate a generator shaft, and that can come from a wide variety of sources. There are four major generator designs based on the primary source of energy, or prime mover, used to turn them. These are water turbines, engines, gas turbines, and steam turbines. Water turbines in hydropower plants direct water flow through dams containing turbine blades attached to one end of a generator rotor. When the water turns the turbine, it also turns the rotor and electricity is generated. Steam turbines are turned by steam from water heated by heat from controlled nuclear reactions or from the burning of fossil fuels. Fossil-fired generators vary in efficiency from 30 to 65%, i.e., a 30% efficient plant uses over twice as much fuel as a 65% efficient one. Modern plants tend to be much more efficient than older ones.

Electric System

A phrase used to describe the electric generation, transmission, and distribution components as one complete, integrated system. *See also the Bulk Power Market.*

Electricity Broker

An electricity broker is a company or individual that facilitates the sale of power to customers, but does not take title to the power and is therefore not the seller. An energy broker earns commissions like a real estate or insurance broker or agent. This contrasts with an energy marketer that actually owns the energy it sells and makes a profit on the mark up between purchase and sales price.

Electricity Generator

An electric power generating plant or the owner or operator of such a plant or plants. When reference is made to a plant, the term usually refers to a single or specific plant. For example, “When the generator trips off-line...” When reference is made to a source of supply (the person or firm selling power) the term is generally not plant specific but refers to the power resources available to the plant owner, typically multiple plants and/or power contracts. For example, “When the generator sells power to the PX ...”

Embedded Costs

This refers to the historical costs of all the capital assets (equipment and facilities) used in an electric utility's system. Each asset goes on the books at its initial cost. Capital assets are depreciated over time, so the value carried forward on the books declines over time. The resulting value is called “book value.” Book value for an asset may be less than the value of the asset if it were sold on the open market, i.e., the market value. One of the benefits of cost of service regulation is that current prices are tied to the low embedded costs of existing assets. Generally, this means power costs are lower than they would be in an open market.

Energy, U.S. Department of (DOE)

An agency created by the federal government in 1977. It provides information to achieve efficiency in energy use, diversity in energy sources, a more productive and competitive economy, improved environmental quality, and a secure national defense. Before 1977 these functions were provided by various predecessor Federal organizations. Most states have an agency, sometimes called the state energy office or energy department, tasked with some of the same missions, especially energy conservation. Also included under the U.S. DOE umbrella are the federal power marketing administrations, oversight of the Tennessee Valley Authority, and the Federal Energy Regulatory Commission.

Enhanced Services or Value-Added Services

Any service offering that is not essential to the delivery of basic service. Historically this included extra transformation of power (stepping-down the voltage), power quality monitoring and improvements, energy audits, energy efficiency services, facility maintenance, and so on. Prior to deregulation these services were often provided for free or at a subsidized price. In the post-deregulation world, utilities are offering a long list of services on a fee basis as a means of increasing the products they can sell to customers. With few exceptions, utilities will not offer these services for free after deregulation.

Exempt Wholesale Generators (EWAGS)

In an effort to diversify domestic power supplies in the wake of the oil embargo of the 1970s Congress, in 1978, passed the Public Utility Regulatory Policies Act (*PURPA*) allowing non-utilities, called independent power producers to build power plants and requiring local utilities to purchase the output on terms favorable to developers. Eventually, the ability of the IPPs to provide power, increasingly based on natural gas as a fuel, outstripped the willingness of local utilities to buy it. Consequently, Congress created new categories of power producers, ultimately authorizing utilities to enter the business as *exempt wholesale generators, or EWAGS*.

F

Federal Energy Regulatory Commission (FERC)

A federal agency that regulates the price, terms, and conditions of all interstate wholesale energy and transmission transactions, natural gas as well as electricity. For example, FERC approves and enforces the transmission rates that utilities charge each other to move power through the bulk power market. FERC has led the deregulation of natural gas and electricity prices by requiring open access to gas pipelines and electric transmission systems. FERC also licenses and inspects private, municipal, and state hydroelectric projects and enforces provisions of the Federal Power Act, such as requests to use transmission facilities by third parties. FERC is a five-member commission within the U.S. Department of Energy that regulates wholesale transactions. FERC commissioners are appointed by the President.

FERC Mega Notice of Public Rule Making (Mega NOPR)

Reacting to industry innovation, FERC requested comments from consumers and industry about new ways of structuring gas transportation in what it called a Mega-Notice of Proposed Rulemaking, or Mega-NOPR, in July 1991.

FERC Orders 436 and 500

FERC issued a series of Orders aimed at introducing competition into the pipeline business while retaining control of the transportation function. The first of these, Orders 436 and 500, were issued in the late 1980s. These orders allowed consumers to negotiate prices directly with producers and required pipelines to transport the gas resulting from these negotiations. These rules maintained the traditional role of pipeline owners as marketers (buyers and sellers) of natural gas, but allowed producers to secure access to pipelines for their own use. This allowed producers to balance supplies across production regions. These Orders stimulated innovation in pipeline tariffs to reflect variations in reliability (firmness) and transportation contract duration.

FERC Order 636

FERC Order 636, issued April 9, 1992, “restructured” (in FERC’s words) the natural gas industry to stimulate competition by consumers for gas supplies and transportation. Order 636 required pipeline companies to open access to capacity to any and all transporters and to unbundle transportation services so as to allow customers to select supply and transportation services from any competitor in whatever quantity and combination they desired.

FERC Order 888

Adopted in 1996, this order required utilities to allow everyone access to utility-owned electric transmission lines to move power from generators to customers. Applied only to wholesale power markets because FERC has no authority over retail markets but it released pent-up demand and spurred inter-regional power trading, resulting in low-cost power flowing to high-cost areas and a nation-wide leveling of wholesale power prices. Current wholesale power prices average about 3 cents power kilowatt-hour. (Put this in glossary?)

Fixed Costs. See Sunk Costs.

Fixed Price

A price that remains the same for a set time period. Energy buyers can solicit bids for energy supplies based on a fixed price for a specific contract term. This contrasts with price quotes that are tied to an index that floats up and down, typically a fuel cost index.

Forward Market

Options and futures allow a consumer to establish the price they are willing to pay for a product at some future point in time. Options and futures trade in terms of months into the future. For example, I could buy an option to purchase a specific quantity of natural gas for \$ 3/ MMBtu 1 or 2 or 3 or up to 18 months from now. The prices for natural gas in each of those months are called “forward” prices. The trend in those prices, in other words, the price in each successive month is called a “forward price curve.” Forward markets and forward price curves are essentially a forecast of what commodity prices will be made by people trading in commodity markets. Forward price curves are not necessarily accurate predictors of future prices, because commodity traders include individuals who are not directly involved in production of the commodity in question. These other traders may react to events differently than the commodity producer does. As a result, they may err in their sense of where prices will be in the future. Nevertheless, a forward price curve provides an indication of where “the market” thinks prices

are going that price sensitive consumers of commodities should monitor, just in case the market is right.

Franchise

An agreement that permits a company to conduct business within a township, village, city, or other local government unit. Typically utilities are granted exclusive franchises to serve in a specified area. Franchises are granted by both states and municipalities. Municipalities often charge a franchise fee as a way to generate revenues and to compensate for use of municipal rights-of-way. States may also grant utility franchises. As a result, franchises may overlap. *See also Service Area.*

Fuel Cell

A fuel cell is a device that generates electricity and hot water through a chemical reaction by combining hydrogen and oxygen. These devices, which are starting to be commercially marketed, are most often fueled by natural gas, methanol ("wood alcohol"), or hydrogen. The hot water produced as a by-product of the chemical reaction can be used in heating systems. Fuel cell efficiency in the electric-only mode is between 40% and 60%. When waste heat is captured and used the overall efficiency increases to 70% to 90%. Most fuel cells are modular, so the fuel cell can be serviced without shutting it down and requiring back-up power. As a result, fuel cells are being viewed as potential substitutes for grid-supplied power. Fuel cells are already being used in limited applications to improve power quality for sensitive loads, such as computer chip manufacturing.

Fuel Component or Fuel-Cost Adjustment

Generating fuel costs can be highly variable. This variability can make it difficult for a utility to set rates because if the utility pays more for fuel than it planned, it will make less money. To deal with this uncertainty, regulators integrated fuel-cost adjustments into rate designs. This allows utilities to pass through changes in fuel costs. Typically, the rate allows for slight adjustments in the kWh charge from month to month. Energy suppliers will still face uncertain fuel costs. As a result, it is expected that prices will still be quoted in reference to a fuel cost index or spot market price. For example, power will be quoted as a discount off the spot market price (which is unknown until the day power is consumed). This form of pricing (index-based pricing) guarantees consumer savings compared to spot prices without putting undue risks on to the supplier.

Fuel Cost Adjustment. See Fuel Component.

G

Gas Turbine

Gas turbines are based on jet airplane engine designs. Air is sucked into the gas turbine where it is compressed. This increases the density of the air (which increases combustion efficiency) and heats it. Gaseous fuel is introduced in a combustion chamber and the resulting exhaust is used to drive a turbine attached to a generator rotor. Electric generators based on this design are usually called simple-cycle combustion turbines, or simply combustion turbines (CTs). Steam

generators are often used in conjunction with gas turbines in what are called combined-cycle combustion turbines, or CCCTs. Natural gas is used to fuel most new plants and is partly responsible for the high heat rate of new plants. Coal is an abundant native fuel that can be converted into gas similar to natural gas for use in gas turbines. Plants that include coal gasification are called integrated gasified combined cycle plants (IGCCs). IGCC plants are cleaner burning than old-style coal plants. *See also Turbine Generator.*

Generating Reserves

Generating reserves is the excess capacity that regulators require utilities to have to meet emergencies during peak demand periods. The amount required, stated in percentage of peak demand, is called a reserve margin. Typical reserve margins are 15 to 20 percent. Reserves can be provided by having idle plants in the utility generation inventory or having unused plant capacity during peak periods (i.e., all plants are not running at full capacity). Having idle capacity is expensive. Another way to provide reserves is to rely on the idle capacity of adjacent utilities. This is much more economical, especially if the loads of adjacent utilities peak at different times.

Generation Charge (also known as Shopping Credit or Standard Offer)

Deregulation language varies from state to state. This phrase refers to the component of the power bill that is associated with the cost of producing electricity. When there is competition between electric companies, this charge depends on the terms of service between the customers and the supplier. In other words, under competition, it varies depending on the supplier the customer chooses. Some states refer to this generation charge as the “shopping credit” or “standard offer.” Unfortunately, the term “standard offer” is also used by many states to refer to the default service rate offered to customers who do not choose or cannot secure power supplies from an alternative supplier.

Generation Company (Genco)

This is a company that operates and maintains a power plant that generates electricity. The new term, Genco, is used to designate firms that are generation companies exclusively. Gencos may be utility subsidiaries, but they do not own wires or perform traditional utility service functions. The term Genco includes all of the various legal terms for power generators, including Qualifying Facilities, Independent Power Producers, and Exempt Wholesale Generators.

Gen-Set

Engine generators, or gen-sets, use an engine as a prime mover to turn the generator rotor. Typical gen-sets are fueled with diesel oil or natural gas. Gen-sets are also often used by consumers for emergency power.

Green Power

Electricity that is produced from sources that are thought to be environmentally cleaner than traditional sources. Green power is usually defined as power from renewable energy that comes from wind, solar, biomass energy, etc. There are various definitions of green resources. Some definitions include power produced from waste-to-energy and wood-fired plants that may produce air emissions as bad as conventional fuels. Some states have defined certain local resources as green that other states would not consider green. For example, the state of Texas has

defined power from efficient natural gas-fired power plants as green. Some northwest states include power from large hydropower projects as green although these projects damage fish populations.

Various states and the federal government are working to clarify labeling for green power. GSA and DESC both request bids for green products that fit the environmentally beneficial guidelines used by the government. Any agency can purchase green power from GSA or DESC and be confident of the source. Further clarification of green power purchasing will be forthcoming as a result of Executive Order 13123. FEMP, GSA, and DESC will provide Federal agencies with information as deregulation proceeds.

Grid or Power Grid or Bulk Power System

A network for the transmission of electricity throughout a state or region. The term grid usually refers to the transmission lines; however, the power system is designed as an integrated system that specifically relies on generation and transmission to move power from location to location. The transmission grid is designed as a network, meaning the connections allow two-way power flows. In contrast, local distribution systems are generally designed for power to flow one way, from the transmission lines to end users. The term “radial” is applied to these one-way transmission and distribution elements. One exception is for transmission lines that link generation to the bulk power network. Obviously power flows one way along these lines. They are called integrating transmission lines because they integrate generators into the grid.

The nation’s transmission network is divided into three major systems (Western, Eastern, and Texas), which are electrically isolated from each other. Within each of these networks (called “interconnections”), transmission systems are operated at a regional or utility-area level by “control centers.” There are roughly 140 control centers in North America. Each control center manages power flows within its own boundaries and coordinates flows across boundaries with adjacent control areas. If there is a major system failure, the network breaks down into component systems based on these control areas. As a result, the entire country (or interconnection) is saved from a black out. *See also Transmission System, Wholesale.*

H

Heat Rate

The efficiency of a plant is reflected in a metric called the heat rate, which is expressed in terms of Btus per kilowatt of power (e.g., 9,500 Btus/kWh). One kWh of power produces 3,412 Btus of energy, so a plant with a heat rate of 3,412 would be perfectly efficient. This is an ideal unlikely to be achieved, although improved heat rates are the focus of intense research sponsored by DOE and industry. The heat rate of best-of-class machines is approximately 6,500 Btus/kWh whereas the average heat rate for all generators in service today is about 11,500. Thus, new machines burn roughly half the fuel of the typical plant, with a similar reduction in carbon dioxide and other air emissions.

Heating Degree Days (HDD)

A measure of how cold a location is relative to a base (normal) temperature over a period of time. The heating degree days for a single day is the difference between the base temperature and the days average temperature. If the daily average is greater than or equal to the base, this would be a "zero" heating degree day. Sixty-five degrees is a common baseline, so one day with an average temperature of 66 degrees would be one HDD. Five days in a row at that temperature would be 5 HDD, and so on.

Hedge. See Price Ceiling.

Holding Companies

A holding company may own a number of utilities that provide retail service in multiple states, usually adjacent states. Each utility owned by a holding company is a separate corporate entity, with its own board of directors. A good example is the Southern Company, which owns Georgia Power, Mississippi Power, and others. About two dozen IOUs operate as holding companies. The retail utility subsidiaries are regulated by state PUCs; however, dealings with the parent holding company cannot be regulated by individual states because they are interstate transactions. Instead, they are regulated by the Interstate Commerce Commission. The wholesale transactions of holding companies are also regulated by the FERC. The Public Utility Holding Company Act of 1935 (PUCHA) was passed to restrict the activities of holding companies due to abuses by holding companies early in the history of the industry. As a result, holding companies cannot participate in certain other utility businesses (water and telephone, for example). Utilities that are not part of a holding company may engage in these activities with the consent of the state PUC. Holding companies view this as unfair and are moving to repeal PUCHA.

Hour-Ahead Market. See Power Exchange.

Hub

Commodities are produced and consumed all over the place. Setting prices based on where a commodity is produced and consumed adds transportation costs that mask the underlying market value of the commodity. Therefore commodity markets establish prices based on delivery and receipt at specific points. The points that electricity and natural gas trade are called hubs. There are many trading hubs, which allows traders (and markets) to set market value based on the unique features of commodity production at each hub. For example, electricity that trades at the California-Oregon Border (COB) hub, reflects the fact that the power coming into that market is dominated by hydropower. Similarly, natural gas trading at the Henry (La.) Hub is from on-shore natural gas wells. The difference in price between hubs provides buyers and sellers an indication of the potential value of transporting energy between two hubs. It also provides traders with a basis for exchanging energy between two areas on an equal basis. For example, if I purchase electricity in Oregon, but need it in Florida, I can simply trade the power I have in Oregon based on the COB price for power at a hub in Florida, at the price that prevails there. That way I don't have to move power from Oregon to Florida. This is a good deal for me, because I can't physically move the power that way. Even if I could, I would lose a fraction of the power to transmission losses.

Hydropower. See Electric Generation.

I

Implementation Costs

Implementing deregulation as directed by legislation or PUC orders often imposes costs on utilities that were not anticipated in current rates. As a result, many utilities have requested compensation for these costs in new, or anticipated future, rates. Examples of implementation costs include setting up power pools or independent system operators and educating customers to changes in power supply options.

Independent Power Producer (IPP)

An electricity generator that sells power to others but is not owned by a utility. IPPs were spawned by the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 210 of PURPA required local utilities to purchase power from IPPs at the utility's avoided cost, which was often greater than what an IPP could produce power for. Such plants are called "qualifying facilities" or QFs. Today there are a variety of non-utility-owned generators. Various Federal laws govern these companies and their plants giving rise to a confusion of labels.

Index Pricing

Commodity markets are volatile. Sellers have the option to sell into the commodity market, at some unknown price in the future, or sell to a consumer for a specific price on a long term contract. If, however, the price in the contract is below that of the market, the seller will have given up profits. Similarly, if the contract price is higher than the market, the customer will lose money over simply purchasing from the market without a contract. One way to share this risk is to tie the price in the contract to a market price, or index. This is similar to an adjustable rate mortgage, where the borrower doesn't know the exact interest rate they will pay in the future, but they know it will track changes in interest rates. Index prices are normally offered at a discount to the market price. (Why would anyone agree to pay more?) An example would be an index price of "Henry Hub minus 3%." This translates into, "Your price will be whatever the price of natural gas is at the Henry Hub (a major gas trading market), less 3%." In other words, you will always save 3% over purchasing gas directly from the Henry Hub market. Thus, your gas price may go up and down with Henry Hub prices, but your price will always be lower than that price.

Independent System Operator (ISO)

ISOs are new institutions that operate regional transmission networks. Presently, ISOs do not own transmission assets. These continue to be owned by existing utilities. However, ISOs may evolve to replace the utilities as owners of transmission. ISOs are governed by boards of directors that represent the interests of all of a transmission system's users, not just transmission owners. The ISO's mission is to ensure access to transmission by all users to facilitate competition in power supply markets. ISO charters vary by region. Some are responsible for transmission planning, rate setting, transaction processing, and construction of new facilities. Generally, ISOs subsume the functions of and eventually will replace some of the current 140-odd control centers. Another name for an ISO is Independent Tariff Administrator (ITA). Typically, an ITA is not as fully engaged in transmission planning and operations as an ISO.

Transmission Companies, or Transcos, are a third variation on the ISO theme. No Transcos are presently in operation in the United States. Transcos are generally expected to be for-profit firms, in contrast to ISOs and ITAs. Transcos are also expected to own transmission assets. *See also Grid and Bulk Power Market.*

Independent Transmission Company

An independent company that owns and operates a transmission system for a group of utilities. Generally an independent transmission company also owns generation, in which case it is called a “generation and transmission” company or G&T. Typically, G&Ts are formed by cooperatives and other not-for-profit utilities that want to pool the costs and risks of power plant development. Deregulation of wholesale power markets is expected to encourage utilities to sell off transmission to new, independent transmission companies. These are referred to as Transcos.

Integrated Gasified Combined-Cycle Plants. See Gas Turbines.

Integrated Resource Planning (IRP)

A planning process in which utilities look at multiple sources to meet demand for power. In addition to traditional fossil fuel plants, utilities would give equal or greater weight to alternative supply options, renewable generation, and energy conservation. IRP was fashionable in the 1980s and early 1990s because it engaged all stakeholders in utility planning. However, it fell from favor when natural gas prices fell in the late-1980s, making new generating plants and new power supplies relatively inexpensive.

Intermediate Plants

In between peakers and base load plants is a class of plants called *intermediate* or *mid-merit plants*. These plants are run more often than peaking plants but not as often as base load plants. They are generally based on a combined-cycle combustion turbine design. Hence they use a higher cost fuel than a base-load plant but these higher fuel costs are offset by better heat rates. *See also Peaking Plants, Base-Load Plants.*

Interruptible Rate

A special utility rate discount given to those who agree to have their service reduced or curtailed as needed by the utility. Circumstances for service interruptions can be periods of high demand or high cost or periods of short supply for the utility, or system emergencies. Large companies or industrial customers often have this type of contract with utility companies. The benefits to participating customers are two-fold: first, significantly lower overall power costs and second, reduced reliance on power during high-cost periods. The benefit to the utility is reduced on-peak generating reserves. The reduced need for generating reserves reduces the utility’s costs, which all customers benefit from in the form of slightly lower rates.

Intervene

To intervene is to participate in the regulatory process through which utility rates are set.

Inverted Rate

An inverted rate provides consumers with an incentive to decrease power consumption by increasing the cost per kWh as total use increases. Both declining block and inverted rates can have multiple blocks. The simplest form consists of two blocks. However, three or four blocks, each with a different kWh charge, are not unusual. This kind of rate design requires regulation; it would be impossible to implement in an open and competitive market. *See also Declining Block Rate.*

Investor-Owned Utility (IOU)

Any company owned by stockholders that provides utility services. IOUs are for-profit firms. They raise capital by issuing stock to investors, hence the term investor-owned. Roughly 250 of the 3,200 utilities operating in the United States are IOUs. These IOUs provide power to almost 70% of all consumers. Because they are for-profit firms with a responsibility to earn profits for stockholders, instead of keeping rates low for consumers, they are regulated by state commissions. Holding companies are IOUs with multiple utility subsidiaries in different states. Because holding company subsidiaries operate in multiple states they are regulated at the federal level by the Interstate Commerce Commission. *See also Holding Companies.*

K

Kilowatt (kW) of Demand

This is equal to 1,000 watts. It is used as a measure of demand for electricity independent of time. Ten 100-watt light bulbs use one kW (10 times 100) of electricity. *See also kilowatt-hour.*

Kilowatt-hour (kWh)

The basic unit of electric energy for which most customers are charged. It incorporates the kW demand and the duration of use in one metric. For example, ten 100-watt light bulbs left on for one hour use 1,000 (10 times 100) Watt-hours, or 1 kWh. If they burn for a total of 5 hours, they will use 5 kWh. If all 10 burn for 5 hours and only 5 burn for the next 5 hours, they will use a total of 7.5 kWh. This ability to integrate demand and duration demonstrates why kWh is favored as a way to measure and calculate electricity use. Consumers are charged for electricity in cents per kilowatt-hour.

Kilowatt-Hour Charge or Usage Charge

Energy costs are recovered through a usage or kilowatt-hour charge. The simple form of a kWh charge is a fee that is the same regardless of time or quantity of use. Many small utilities use this kind of rate design because it is easy to administer using simple kWh meters. However, most large utilities employ more sophisticated cost recover mechanisms or *rate designs*.

L

Load or Demand or kW Demand

The amount of electricity being used at a specific point in time by a customer, circuit, or system. Demand is measured in terms of kilowatts (kW), not in the more familiar kWh, which reflects demand over a period of time rather than in an instant of time. *See also Kilowatt and Demand.*

Load Aggregation

When multiple customers join together to solicit bids to supply power. Present deregulation regulations base competition for power supplies on individual meters, rather than customers. In one sense, a building or firm with multiple meters aggregates its own loads when it requests a power supply bid for its total energy needs. Federal agencies may join load aggregations that include other Federal agency loads or participate in aggregations of other non-Federal governments. For the most part, GSA and the U.S. Department of Defense aggregate Federal agency loads on behalf of other Federal agencies. It is assumed that aggregation will result in better bids on competitive solicitations. However, early experience has not shown that to be the case. Nevertheless, considerable costs are involved in competitive power procurements, so joining an aggregation may significantly reduce those costs.

Load Center

A large concentration of customers, like a metropolitan area, is called a load center. Power from remotely located generators travels to load centers along high-voltage transmission lines.

Load Factor

Customers with similar electricity usage can have significantly different electricity bills based on demand charges. If a greater proportion of electricity is used during peak demand periods, both demand charges and any TOU rate impacts will be greater than for customers with usage that is more constant over the course of the day. A common metric for evaluating this impact is the *load factor*. Load factor is the ratio of peak demand to average energy use. It is calculated as follows:

Load factor for one month = [total **kWh** use for the month / number of hours in the month: ~720 hours] / maximum **kW** demand for billing interval, such as hour or 15 minutes.

Typical homes have a load factor of .45, businesses about .6, and industries between .85 and .95. A load factor of 1 results when electricity use is constant throughout the day, week, and month. In general, the higher the load factor, the lower the average cost of power per kilowatt-hour when all charges are factored in. In other words average kWh cost (the total bill divided by total use in kWh) is lower for customers with higher load factors. The lowest average kWh cost (and total electricity bill) is obtained when the load factor exceeds 1, as that indicates a shift in consumption to lower cost, off-peak periods.

Load Management.

Load management involves changing the way energy is used on a daily or seasonal basis, usually to reduce electricity bills. There are three basic load management strategies:

- 1) Peak clipping is the curtailment of on-peak power use. Peak clipping reduces both peak and total energy use, because the use is curtailed and not made up later.
- 2) Peak shifting is like peak clipping except that the activities that would have used energy on-peak are rescheduled to other periods. In other words, the same amount of energy is used, but some of that use is shifted from peak to off-peak times. Sometimes peak shifting results in an increase in total energy use, albeit at lower unit costs, so the total bill is reduced.
- 3) The third form of load management is valley filling. A valley is a period between two peaks, hence the name. Utilities have sometimes encouraged power use during off-peak periods by discounting the price. Valley filling does not necessarily require that energy use shift to a valley period. In fact, the utility's goal in offering off-peak power rates is to increase total energy use by encouraging off-peak use.

Load management is generally accomplished through control of specific energy-using operations. Historically, utilities have provided control signals to this equipment or advised customers when it is time to curtail use.

Competitive pricing of electricity will result in prices that vary on an hourly basis. These prices will act much like utility load control directions. However, all customers will be able to benefit by adapting energy use practices to respond to changing prices. Presently, power prices are very high during peak periods (typically hot summer days). Prices may also spike due to unseasonable weather and unplanned equipment outages. At the same time, prices tend to be very low, even zero, during low use periods, typically in the spring and fall and late at night or early in the morning. In some countries power producers actually give customers credit for using power during low-use periods (up to 2 cents/kWh). Credits, zero-priced power, and valley filling make both economic and environmental sense, because power plants are less efficient when they cycle on and off or operate at low levels of capacity. As a result, it can actually be less expensive (and less polluting) to give power away during some periods if that will enable the generator to maintain power production at an optimal level.

The future of load management lies not in following utility directions, but in adjusting energy use schedules to follow power price trends, curtailing use during very high cost periods, adopting energy storage, and joining district heating and cooling utilities to take advantage of very low power prices.

Load Management Cooperative

A group of customers or facility managers that forms a cooperative to evaluate their respective load curtailment capabilities during various times of day and seasons. The results are compiled and reduced to allow for non-coincidence of loads and other factors participants believe may make it difficult to shed loads beyond a certain point. This provides a cushion "just in case." The cooperative notifies the utility or capacity market of the potential load available for

curtailment. In regulated markets, the cooperative would negotiate a reimbursement rate or rate discount directly with the local utility. In a competitive market the participants would normally submit a curtailment bid, just like a generator, to the power exchange or ISO. In most competitive markets these bids would be submitted by a third-party authorized to coordinate resources with the power exchange or ISO. The demand bid may offer a range of curtailment options with various prices for each. If a demand bid is accepted, the participants will be notified of the expected quantity of load to curtail, curtailment hours, and duration, along with the price to be paid. Once the expected curtailment is known, the participants allocate the curtailment among themselves based on expected operations during the curtailment period. In that manner participants that are unable to curtail their operations for some reason may rely on another participant to take up the slack. Hence the need for the cushion noted previously. For example, assume 3 firms are each willing to curtail 5 MW of load in exchange for a utility payment. But, when the utility calls for the load curtailment, one of the firms doesn't want to curtail the full 5 MW. They can only manage 3 MW. The other two firms then curtail 6 MW each, so the utility gets the full 15 MW the 3 firms agreed to provide. Over time, the over-and-under curtailments may average out among the firms, or there may have to be a cost adjustment to make each firm whole.

Load Shedding Pool. See Load Management Cooperative.

Lumen

A lumen is a measure of the amount of visible light, such as is produced by a light bulb.

M

Marginal Cost

The change in total costs associated with a one-unit change in the quantity supplied. For an electric utility, this would be the cost of providing an additional kilowatt hour of electricity to a consumer. Marginal cost is an economic concept that assumes quantities of a commodity can be provided in single unit increments. Utility plants are generally large and long-lived. Adding an entire new plant to meet an extra kilowatt of demand is very expensive. Prior to deregulation the cost of this avoided plant was used to determine marginal (or avoided) cost. Presently, commodity markets (or power pools) play this role.

In commodity markets, power owners (many of whom are speculators) offer to sell power to power buyers (again, many of whom are speculators). The owners have secured rights to power capacity that they are willing to sell when the price is right. Prices get bid up by buyers, usually in response to anticipated power demand. If prices are too high, buyers can refuse to purchase and force speculators to sell off supplies at a loss (since power is best used as it is produced). Under regulation, captive customers had to absorb this price risk. Competitive commodity markets shift the risk to speculators. In other words, if a speculator purchases power that they cannot sell at a price they want, they have to discount the price and sell at a loss. In a corresponding fashion, customers absorb the risk of higher prices when supplies are tight. However, customers are also free to avoid using power when prices are high by not operating electricity-using equipment during high-cost periods.

Marginal Price. See Dutch Auction.

Market-Based Price

The price for a commodity or service as determined by the decisions of many buyers and sellers in a competitive market. In general, the phrase “market-based price” is used to refer to a commodity price as reflected in a spot market. However, there are many other markets, including bi-lateral contracts where sales prices are negotiated at prices that differ from spot prices. Similarly, spot prices are for a point in time. Buyers and sellers can protect themselves against unexpected price swings by purchasing a commodity future or option that locks in the price in advance. *See also Marginal Cost.*

Market Clearing Price. See Dutch Auction.

Market Manipulation

See Enron, just kidding. Markets are governed by a combination of rules and procedures and trust among buyers and sellers. Unfortunately, all parties are not always trustworthy and rules and procedures cannot anticipate all situations. Consequently, some traders can figure out ways around some of the rules, without other parties knowing it, and use this knowledge to take advantage of other parties in the market. A classic way to do this is for sellers to collude to set prices. This is patently illegal. Nevertheless, there are ways sellers can “signal,” like Bridge player, to one another without specifically communicating. This is common in the airline industry where one airline will post new fares that are uniformly higher. All the other airlines can see this change when it is posted on the airline reservation system. If the other airlines match the increase, ticket prices will increase. This is still legal, because the airlines didn’t meet to set the price. Likewise, competitive energy markets provide a mechanism for market participants to signal to one another. This only works well if there are a few large traders and they dominate the market. Unfortunately, that is the case in electricity markets and markets for transmission and gas pipeline capacity. There are other ways to manipulate prices that may well be illegal or, at least outlawed once discovered. Enron and others engaged in these during the California power crisis. One is to create an artificial shortage of energy by withholding energy from the market. If the market believes the shortage is real, it will drive prices up rapidly. Another is to combine energy imports and exports to the same market that cancel each other out over time. For example, Enron exported power out of California during the power crisis. It then imported the same amount of power into California. Because the California market “saw” the export, it thought there would be a power shortage and prices ran up. Of course the power import relieved the shortage, but it also earned Enron a much higher price. In reality, no power left the state. The trade was a shell game. Market monitors are supposed to catch these kinds of schemes. Unfortunately, as we learned from California, they are usually discovered only after the profits have been distributed and it is nearly impossible to get any money back. Moreover, by manipulating the price in the entire market, all traders and all trades are damaged and there is no way to make all parties whole again.

Market Marginal Price. See Dutch Auction.

Market Power

The ability of one utility to force a neighboring utility to buy its higher cost power rather than allowing the neighbor to purchase lower cost power from a third utility that would have to wheel the power across the first utility's transmission lines. *See also Divestiture.*

Market Price. See Dutch Auction.

Marketer

An agent who sells electricity or natural gas on behalf of a company that produces the gas or electricity. This term is used interchangeably with "supplier." A marketer has title to the power it sells and makes a profit on the mark-up between the purchase and the sales price. This is in contrast to a broker, who acts as an intermediary between a supplier and a buyer for a commission. Marketers are regulated at the state and Federal level and must apply to and be registered with FERC. Brokers may or may not be regulated at the state level and are not required to register with FERC.

MBtu (MBTU)

This stands for one million British Thermal Units (BTUs). MBTUs is a common unit of measure for natural gas and provides a convenient basis for comparison of the energy content of natural gas and electricity. One Megawatt hour of electricity (1,000 kWh) is equivalent to 3.413 MBTUs. Natural gas is measured in cubic feet. One cubic foot of gas is nominally equal to 1,000 BTUs. Thus, 1,000 cubic feet of gas (normally called one MCF or Mcf (M is the Roman numeral for 1,000; cf is an abbreviation for cubic feet) is equal to 1 MBTU. However, the heat (BTU) content of a unit of natural gas varies. Accordingly, natural gas is usually measured in "therms." One therm of gas is always equal to 100,000 BTU or .1 MBTU. Most major natural gas users purchase gas in quantities measured in tens of thousands of Decatherms. One Decatherms is equal to 1 MBTU.

Mega-NOPR

The Mega-NOPR is the Mega-Notice of Proposed Rulemaking that FERC issued in July 1991 requesting comments from consumers and industry about new ways of structuring gas transportation. This Mega-NOPR led to the end of gas price regulation with FERC Order 636, issued April 9, 1992, which required pipeline companies to open pipeline access to all transporters and to unbundle transportation services allowing customers to select supply and transportation services from any competitor in whatever quantity and combination they desired.

Merit Order

To dispatch power plants based on production costs, i.e., lowest production cost plants first. *See also Production Costs.*

Micro-Generation. See Microturbine Generators.

Microturbine Generators or Micro-Generation

Combustion turbines are used to power jet aircraft. A similar turbine is used in gas-fired power plants. A small turbine is used in vehicle engines to compress air and enrich the fuel-air mixture to improve combustion efficiency. Microturbine generators use a variation of vehicle turbines to produce electricity in a miniature power plant. This is a completely different turbine design from power-generating combustion turbines. Microturbine generators can run on liquid or gaseous fuels derived from natural gas, wood, or garbage. They are being marketed to households and businesses as an alternative to grid-supplied power. They are also being marketed as an alternative to batteries for back-up power. The installed cost of microturbines is expected to be competitive with grid-supplied power (including transmission and distribution costs).

Mid-Merit Plants. See Intermediate Plants.

Municipal Utility

A provider of utility services owned and operated by a city government is called a municipal utility. Municipal utilities are generally not subject to state regulation under the belief that consumers can control the actions of the utility through the electoral process. Municipal utilities currently are able to raise capital by issuing tax-exempt bonds which reduces their cost of operations. Because most states do not regulate municipal utilities, state deregulation legislation does not generally apply. However, if a municipal utility opts to deregulate itself, it is often covered by the same legislation as regulated investor-owned utility. Municipal utilities usually take one of two forms. They can be a part of the municipal government or a separate entity under the control of the municipal government, or they can operate as a municipal corporation granted by the State altogether separate from the local municipality.

N

National Association of Regulatory Utility Commissioners (NARUC)

This is an advisory council composed of utility regulatory agencies of the 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands. The primary objective of NARUC is to serve the consumer interest "by seeking to improve the quality and effectiveness of public regulation in America." NARUC holds periodic meetings of regulators, has standing committees, and advises state and federal bodies on utility legislation.

Natural Gas Act of 1938

Created the Federal Power Commission (FPC) and directed it to regulate natural gas pipelines, but not wellhead prices. Like all federal regulations, jurisdiction was limited to pipelines in **interstate** commerce. **Intrastate** pipelines were beyond the reach of FPC price regulation.

Natural Gas Policy Act of 1978 (creation of FERC out of the old Federal Power Commission)

This act created the Federal Energy Regulatory Commission (or FERC) out of the old Federal Power Commission. The act also accelerated domestic gas exploration in the 1980s by removing federal price caps that had been in place since the 1950s. This resulted in an increase in natural gas production and a decline in gas prices.

Net Metering

Generally, net metering means allowing customers to “sell” power back to the utility at the same rate at which it is purchased. Historically, this has been accomplished by letting customers “run the meter backwards” when they had surplus electricity from an on-site generating device. Net metering regulations were adopted to encourage customers to install solar and other renewable generating devices. Typically, net metering laws favor small residential and farm customers. In point of fact, the only kind of electric meter that can “run backwards” is a residential meter. Larger customers that do not have residential scale meters have to install a second meter to measure the output of on-site generating devices. The use of two meter readings to implement net metering is technically known as a “buy-sell” contract. The customer “buys” power through a regular utility billing meter and “sells” surplus power back to the utility using a separate meter. Two meters costs the utility more. As a result, the additional costs are passed on to the customer and may exceed the value of any surplus power sale. Further, once two meters are in place, the utility may use a different purchase price than the customer’s rate.

Approximately two dozen states have net metering requirements; however, very few customers take advantage of them. (It is likely that many small customers simply run the meter backward without telling the utility. If the utility suspects a meter is running backwards, they may replace the meter. Most newer meters are designed to prevent reverse operation.) Although more states are adopting net metering rules, and Federal legislation has been introduced to mandate net metering, it is an anomaly in the face of utility deregulation. Specifically, it imposes regulatory requirements instead of reducing them and it may require utilities to purchase power from customers while deregulation rules prevent the utility from selling power to these same customers. Because true net metering (residential-scale meters that run backwards) has a limited application, increased customer participation is unlikely despite new rules. As a result, buy-sell arrangements will most likely be used in future rates. It is likely that buy-sell arrangements will peg the purchase price of customer-generated power to a spot market, which would not include the transmission and distribution component of rates, thus undermining the value of the surplus power the customer is trying to sell. Regardless, net metering, in the pure sense, is not applicable to most federal customer sites, because they do not have residential-scale meters that can run backwards. If customers are required to enter into buy-sell arrangements to implement net metering, the sale price needs to be reviewed.

Network. See Grid, Transmission System.

Nominating

Wholesale (and large) natural gas customers have to tell the gas pipeline company how much gas they are going to need and where it is coming from, so the pipeline company can make sure there is enough room in the pipeline to serve all of its customers. This is called nominating. Usually, customers nominate monthly, but some companies require more frequent estimates. Errors are made up by the pipeline company (or the gas supplier) in a process called balancing. If the errors average out over time, there usually isn’t an extra charge. If there is a persistent imbalance, there will be an extra charge.

Non-Coincident Peak Demand (NCP)

Utility rates use maximum demand (measured in kW, not kWh) as a means to allocate fixed costs to large customers. If a customer has more than one meter at a site, the utility may add up the demand readings to find the maximum demand. Many meters only register the maximum demand reading and do not note when it occurred. If multiple demand readings are totaled to calculate total demand irrespective of when they occur, it is called non-coincident demand. If the demand readings are totaled for the same time interval, such as the system peak, it is called coincident demand. Because non-coincident demand uses several maximum readings, it is almost always greater than coincident demand, which uses the sum of demands at a single point in time, which may not be the maximum for all meters. In order to correlate demand across multiple meters, it is necessary to either have a totalizing meter (a conventional meter that continuously compiles multiple meter readings or a time-of-use or recording meter that can time-stamp meter readings. Customers with non-coincident or non-time-of-use demand meters may pay more than they would if they had coincident or time-of-use demand meters.

Non-Firm Purchase

Purchases of any commodity is on an "as available" basis. Spot market prices fluctuate as a function of demand and availability. One way to reduce price fluctuations is to offer to sell (or purchase) on a non-firm basis. With a non-firm purchase, there is no commitment on the part of the seller to continue to supply the commodity under certain circumstances, usually supply limitations. Non-firm electricity purchases are common in areas with resources that are dependant on variable generation, such as hydropower or renewables. They may be available in other areas where economic factors govern availability, such as when the power purchased is surplus to a utility's own needs or when power is offered during non-peak demand periods. Non-firm sales are also used in the natural gas and electricity transportation markets, where access to transportation assets is granted on a non-firm basis. For example, large gas users may secure pipeline transportation on a non-firm basis. When residential loads require the use of this capacity, the customer is not allowed to use the pipeline.

North American Reliability Council (NERC)

The New York blackout of 1965 was a wake up call to the power industry. The industry responded to the blackout by creating a voluntary, utility-managed reliability organization, the North American Electric Reliability Council (NERC). NERC divided the nation into ten reliability regions, with each region covering multiple states (except for the Texas-specific Electric Reliability Council of Texas, ERCOT). The largest council is the Western States Coordinating Council (WSCC), which covers the entire Western Interconnection, including 11 western states, two Canadian provinces, and the northern portion of Baja California in Mexico. The smallest is the Mid-Atlantic Coordinating Council (MAAC) covering New Jersey, the District of Columbia, and most of Pennsylvania and Maryland.

Nuclear Power

Nuclear energy is produced using steam driven turbines, just like fossil-fueled plants. However, the steam is produced from the heat of controlled nuclear reactions. Nuclear reactors produce radioactive waste but little or no air pollution.

O

Off-Peak/On-Peak

Blocks of time when energy demand is low (off-peak) or high (on-peak). Typically, on-peak power prices are higher both because production costs are greater and as a means to discourage on-peak power use and growth. Historically, on- and off-peak periods were defined by utilities and/or regulators. In competitive markets demand drives prices, but so does other factors. As a result, peak demand periods will not be the only times when market prices are high. As a result, on-peak periods will not be as predictable as they are with present utility time-of-use rate schedules.

On-System Sale or System Sale

A sale to customers where the delivery point is on (or directly interconnected with) a system (transportation, storage, and/or distribution) operated by the reporting company is called a system or on-system sale. Typically a system sale is a wholesale transaction based on an assumption by the seller that they have adequate capacity to satisfy the sale somewhere within their system (or options to make up any shortfall). The resources that make up the sale are not plant-specific, but from the “system” or entire portfolio of resources and power purchase agreements (and market purchases). System sales are fairly common in wholesale markets. Usually, system sales are desirable because they are linked to a known portfolio of resources rather than an individual plant (which may not operate all of the time) or unknown resources.

Open Access

A concept originally promoted in the natural gas industry, requiring transmission system (pipeline) owners to allow use of their transmission system by third party producers. The Federal Energy Regulatory Commission (FERC) first promulgated the reduction of barriers to pipeline access by third parties in Open Access Rules 436 and 500, and further defined open access terms and conditions in 1992 through FERC Order 636, the Restructuring Rule. Rule 636 had a revolutionary impact on the natural gas industry and wholesale gas market and established a precedent for FERC to follow in opening transmission access in the electricity market.

Operating Expenses

Operating expenses consist primarily of generating-plant fuel costs and labor. They contrast with fixed costs, such as debt repayments. Fuel costs are typically the largest operating expense and they vary depending on how much power is produced (i.e., the more power generated, the more fuel needed to fire the plant). Labor costs vary somewhat with power production, but are mostly constant (i.e., the same amount of people are needed to run the plant whether it is operating at full capacity or half capacity).

Operating Hour

Real-time, now, the hour during which power is being generated and consumed. System planners and operators prepare in advance to meet demand with generation, but those plans play out during the operating hour.

P

Peak Demand or Peak Load

Power demands on a system vary. The maximum demand (kW or MW) on the system over a specific interval (i.e., a year, month, day, etc.) is the system peak demand and the magnitude of the load is the peak load. The time it occurs (i.e., hour, 15-minute interval within an hour, etc.) is the peak demand period. *See also Off-Peak, On-Peak.*

Peak Load. See Peak Demand.

Peaker. See Peaking Plants.

Peaking Plants or Peakers

Plants that are used to meet peak loads. These generally run fewer than 400 hours a year. Utilities select plants that can be cycled easily, such as combustion turbines

Performance-Based Regulation (PBR)

Regulators use performance-based rate-setting mechanisms to link rewards (usually profits) to desired results or targets. PBR contrasts with rate-of-return regulation where the earnings on utility investment are assured regardless of utility performance. Under PBR, earnings vary based on performance against specified goals. PBR has been used to regulate telephone companies with mixed success. It is expected to become more widely used for regulating electric and gas utilities after deregulation when the focus of regulation is narrowed down to local distribution activities.

Phillips Decision

The 1954 Supreme Court decision that gave the Federal Power Commission control over producer prices and transportation for natural gas. In 1954, the Supreme Court determined that regulation of consumer prices required control over both producer prices and transportation in the landmark Phillips decision. Although price volatility was reduced by the Phillips decision, regulated price caps on production and pipelines eventually resulted in a two-tiered market; a price regulated interstate market and a largely market-based intrastate one. The supply

constraints of the 1970s were the result. Producer states had ample gas supplies and transportation whereas user states had neither. The solution came in the form of the Natural Gas Policy Act of 1978.

Photovoltaic (PV) Cells

PV cells are used in solar power panels. They convert sunlight to electrical energy. Electricity is produced in a series of small cells tied into an array. Solar arrays produce direct current (DC) electricity. In most off-grid applications the DC power is stored in batteries and used by DC-powered equipment, typically at 12 volts. In on-grid applications, the DC power is converted into conventional AC power and line voltage, 120 volts. Some power is lost in both battery storage and AC conversion. PV is only one of several ways solar energy can be used to meet conventional energy needs.

Pilot Program

Utilities test new ideas, products, and services by offering them to a limited number of customers. These experiments are called pilot programs or “pilots.”

Power Grid

This is a system of interconnected transmission lines and generators that is managed so that generation is increased or decreased as necessary to meet the requirements of the power consumers who are connected to the grid. *See also Bulk Power Market and Grid.*

Power Marketing Administrations (PMAs)

The federal government owns four power marketing agencies: the Western Area Power Administration, the Bonneville Power Administration, the Southeastern Power Administration, and the Southwestern Power Administration, all within the U.S. Department of Energy (DOE). In addition, it oversees the semi-autonomous Tennessee Valley Authority, which is a federal corporation. Federal power agencies usually restrict their sales to wholesale customers, typically publicly owned utilities. However, they have the authority to sell to federal and state agencies. Some states also have power marketing agencies. Examples include the New York Power Authority and the Lower Colorado River Authority in Texas.

Power Pool

Traditionally, a power pool is a voluntary association formed by utilities to share responsibility for the reliability and integrity of a regional power grid by enabling pool members to share or pool power resources and reserves. Power pools may also engage in coordinated power plant operations to operate less expensive plants before more expensive plants and to share savings among members. Power pools that automatically schedule plant operations to minimize pool costs are called tight pools. Transactions in loose pools are bilateral and discretionary. (The pool cannot change which plants run based on cost.) Historically, power pools were exclusively utility institutions, with primarily IOUs as members. Although pools reduced wholesale power costs, savings were not optimized or shared as broadly as possible and savings were not always passed on to retail customers. Deregulation of the wholesale market caused all power pools to change their membership and operations. Now, pools are open to representatives of all stakeholder groups and plants are dispatched based on bids rather than operating costs.

Power Sources or Source Energy

Power sources are the types of fuels used to produce electricity such as nuclear, fossil fuels (natural gas, oil, and coal), and renewable energy resources (hydro, wind, biomass, and solar). The power source is becoming more critical in commodity purchases because some fuels pollute more than others, particularly coal.

Price Cap

When the price for a commodity has been determined or fixed or limited to some pre-specified maximum it is “capped” or subject to a “price cap.” This price may not change even under high market demand. Price caps are adopted to limit the run up in prices in competitive markets when high, or volatile, prices might hurt too many consumers and undermine confidence in the market. Price controls of any sort are usually a last resort for competitive markets. Price caps have been implemented under both deregulation and merger agreements. Price caps force utilities to absorb the costs of unexpected increases in fuel prices or lower-than-expected retail power sales. Price caps are part of deregulation agreements in California, New England (although the cap increases over time), and most other states. The caps were adopted in these states to ensure that consumer rates would remain fixed over time. Unexpected price increases would have to be absorbed by the local utility instead of consumers. Price caps have also been adopted in some competitive markets, where price volatility has been unusually great. Often this is a signal that something is wrong in the market, usually not enough competitors or price-fixing among competitors. Price caps have been imposed in the wholesale capacity markets in California, the Midwest, and New England because of price volatility.

Price Ceiling

A price cap offered by a marketer to encourage customers to purchase energy on a long-term contract. Because market based prices don't protect the consumer from extremely high prices, some contracts offer the protection of a “not to exceed” level. In exchange for offering a price ceiling the marketer may charge a slight premium when prices are low or may set a price floor, the minimum the customer must pay even if market-based prices drop below it. When combined, this price ceiling and price floor are called a price collar, which protects consumers from high prices and marketers from low prices. Price caps, floors, and collars are called hedges because they provide the buyer or the seller a hedge or protection against unfavorable market prices.

Price Floor. See Price Ceiling.

Price Indexes

Commodity prices change throughout every market day, just as stock prices change. Typically, electricity price changes are tied to the hour of use. For example, electricity supplied for loads at noon is priced separately from that for loads at 1 o'clock. Because power prices are expected to change in the future, power sellers are unwilling to absorb these unknown price changes without charging a premium to cover their anticipated risk. One way to eliminate that risk is to quote retail price bids in relation to actual prices, also called indexes. This is already the case in the natural gas market, where commodity prices are quotes in comparison to commodity market indexes. For example, prices may be quoted as “Henry Hub minus 3%.” The Henry Hub is a trading point used for commodity trades of natural gas. “Minus 3%” means that the price bid

will be 3% lower than whatever the Henry Hub price happens to be on the day the gas is used. This kind of pricing shifts the risk of price volatility to the consumer, but the discounts provide known savings. As a result, the consumer knows they will save money over going into the commodity market to purchase gas on a daily basis.

The alternative to index pricing is some form of fixed pricing. However, a fixed price bid requires some knowledge of what future prices are likely to be, often including commodity prices other than that being sold. For example, spot electricity prices vary as a function of both power demand and natural gas prices. In order to offer a fixed price for power for next year, a seller needs to know what both power and gas prices are likely to do. In most cases, a seller offers a fixed price based on both what they think prices will do and a fudge factor that protects them against unexpectedly high prices.

Pricing Options

Among the different competitive power suppliers there are several types of pricing options being offered. Some may charge the same price for every kilowatt-hour of electricity that you use; whereas others will charge different rates depending on the time of consumption or the amount consumed. Prices may be determined in accordance with whether you purchase other services along with electricity such as energy-efficiency assistance. As electricity markets become more competitive (through the elimination of stranded cost surcharges) prices will tend to be tied to indexes that change hourly. *See also Price Indexes.*

Prime Mover. See Electric Generation.

Private Utilities. See Investor-Owned Utilities.

Production Costs or Variable Costs

A utility's dominant production costs are its fuel costs. These controllable costs are referred to as variable costs. Plants are generally dispatched (started and run) to serve loads based on production costs in what is called merit order, i.e., lowest production costs first. That way the most efficient plants run the most, often minimizing production costs. Since fixed costs are sunk, this has the effect of minimizing total costs.

Public Benefits Fund

Regulated utility rates often include charges that are for activities not directly related to providing utility service. Many states and consumer-owned utilities have implemented programs to encourage energy efficiency, to assist low-income customers with their bills, and to weatherize homes of low-income customers. These programs are paid for through a small surcharge in the bill, called a Public Benefits Fee, typically less than 5%. Many customer-owned utilities, especially municipal utilities, levy a charge on consumer bills to generate general fund revenues to operate the municipality. These funds are jeopardized under deregulation. As a result, deregulation agreements often include a continuation of these fees, usually at a rate of 3% or less. The fees are targeted at supporting what are called public benefit programs. Prior to deregulation, fees collected for public benefits were usually spent by the local utility. Many post-deregulation agreements place these funds into a trust that is spent according to the directives of a non-utility-affiliated third party or advisory board.

Public Purpose Fee. See Public Benefits Fund.

Public Service Commission. See Public Utility Commission.

Public Utility Commission (PUC) or Public Service Commission or Commerce Commission
State regulators have jurisdiction over the rates and sometimes the operations of utilities serving in the state. These regulatory agencies have various names, with PUC being the most common. PUCs may also have jurisdiction over customer-owned utilities, although that is not common. Commissions approve retail rates and utility plans, and also ensure that utilities are responding to customer service requests and are properly maintaining distribution systems. State regulators do not have jurisdiction over corporations with interstate utility operations organized as holding companies. Holding companies are overseen at the federal level by the Interstate Commerce Commission (ICC). The general public can get involved in any proceeding before a PUC or the ICC. Many states actually require utilities to reimburse customer groups that intervene in utility proceedings before the PUC.

Public Utility Holding Act of 1935 (PUHCA)

Since state regulation was not sufficient to control the action of interstate holding companies headquartered out-of-state, Congress passed the Public Utility Holding Company Act of 1935 (PUHCA). The PUHCA restricted the influence of holding companies, provided for regulation of holding companies at the federal level, limited the number and kind of utilities a holding company can own, and gave state regulatory commissions more control over affiliate utilities' rates and services.

Publicly Owned Utility

Publicly owned utilities are member-owned cooperatives or government or municipally owned utilities. Publicly owned utilities are generally exempt from regulation by state regulatory commissions because they are assumed to have the customers' (who are also the owners or voters) best interests in mind when setting rates and service standards. A few states do subject publicly owned utilities to regulatory oversight.

Public Utility Regulatory Policies Act of 1978 (PURPA)

In order to encourage the development of these unique and often small-scale resources and thereby to diversify the domestic power resource base, Congress passed legislation that both allowed non-utilities to build power plants and required local utilities to purchase the output on terms favorable to the developers. Many states passed legislation that went further and mandated the purchase at specific prices. The federal legislation is found in Section 210 of the Public Utility Regulatory Policies Act of 1978 (*PURPA*). This legislation created a new legal category of power plants known as qualifying facilities, or QFs, and new market entrants called independent power producers, or IPPs. *See also Independent Power Producers.*

PX or Power Exchange

A commodity market is often called an exchange. A power pool is a power exchange. California created the California Power Exchange (CalPX) as a new institution to replace the former loose power pool operating in the state. The CalPX operates a wholesale energy (kWh) market open to virtually anyone who wants to trade power. The PX conducts three primary auctions: day-ahead, hour-ahead, and real-time. The day-ahead market trades power in one-hour blocks for each of the 24 hours of the next day. The hour-ahead market allows the PX to fine tune the generation schedule in light of real-time loads and climate. Power exchanges are not exclusive. Other firms also operate power exchanges in California as well as other states.

Qualifying Facility. See Independent Power Producer.

R

Rate, or Tariff

The rate is the price set by the local utility for the power it sells. *See also Rate Making.*

Rate Base

The rate base is the value of a utility's assets, established by state regulations, upon which the utility is allowed to earn a specified return. Utilities raise capital from investors and invest in utility assets that benefit their customers, such as power plants, distribution systems, and other facilities. In order to attract investors, the utility must pay them an incentive like interest that is paid on borrowed money. This incentive is called the rate-of-return and is set by the PUC to be competitive with private-sector investments with similar risk. Regulators only allow the rate-of-return to be earned on specific investments. These are called the rate base. The rate base changes constantly as utilities make new investments. The rate of return can be changed by the PUC when it feels an adjustment is justified. Similarly, the PUC can add or remove investments in the rate base. Historically, regulators have followed utility recommendations on what investments should be included in the rate base and on an acceptable rate of return. Commissions have gotten more critical recently and have been more willing to remove items from the rate base and reduce the rate of return.

Rate Case

Utility rates are established (set) through an often complex and lengthy process called a *rate case*. Because rates are regulated based on cost-of-service, rate cases primarily focus on a detailed examination of historic and/or projected utility costs. As a result, the utility has to open up its financial records for review by regulators and the general public, including competitors, such as vendors of other fuels and adjacent utilities. Rate cases are concerned with two primary issues, the rate level, or amount of money the utility can collect, and rate design, or how they structure the rate to collect necessary revenues. Utilities cannot change rate designs or levels outside of a rate case, although they may request minor changes in rates and therefore request a limited case. The schedule for rate cases is controlled by each utility in most states. In other words, a utility only initiates a rate case when it needs to adjust revenues up (or down) or requires a higher rate of return to attract investment capital.

A few states require utilities to submit to rate cases on a periodic basis and others can order rate reviews independent of the utility. In most states interveners (parties not associated with either the utility or regulator) may request a rate review, although the decision to proceed is up to the regulator. In general, utilities and regulators try to limit the frequency of rate cases. As a result, utilities typically initiate rate cases only when they anticipate lower than expected revenues or rates-of-return, or when they have a significant change in capital investment, such as the addition of a new generating plant. Because fuel costs are a significant component of utility rates, volatile fuel costs can require frequent rate cases. Many states have adopted fuel cost adjustment clauses that allow utilities to adjust rates periodically without a rate hearing.

Rate Design. See Rate Making.

Rate Level. See Rate Making.

Rate Making

Utilities need to recover sufficient revenues to pay all of the expenses incurred, including debt service, returns to investors, and operations and maintenance. The total of these requirements sets the rate level. The process of ratemaking involves translating the rate level into specific rates for each customer, a process called rate design. The rate making ideal is for the cost of service to be perfectly allocated to each customer; that philosophy is one of “cost follows cause.” However, customizing rates for each individual customer is far too expensive and cumbersome. Instead, rate design approximates customer-specific costs by grouping customers into similar customer classes. Rates are then designed to recover costs from a representative customer for each class. Typical rate classes include residential, small commercial, large commercial, industrial, and street lighting

Rate of Return

Regulators allow utilities to earn a rate of return on invested capital raised from investors, a sum that is called the rate base. Regulators set the rate of return in a range that allows a utility to earn a profit on its investment and attract capital at favorable rates (compared to bank borrowing). However, this rate is generally set at a level low enough to protect customers’ interests. Payment of the rate of return allows a utility (and its investors) to recover its investment through rates. Thus, the rate of return allows a utility to recover a return on its investments and a return of its investments, just like payments of interest and principal (respectively) on a bank loan. *See also Rate Base.*

Real-Time Market. See Power Exchange.

Real-Time Pricing or Time-of-Use Pricing (or Rates)

Power production costs (and value) vary throughout the day and season. Ideally, customers would pay these so-called marginal costs directly rather than paying an average price that masks the variation in costs. Some utilities offer rates that capture these effects either in true real-time prices or somewhat simpler time-of-use rates that track use and costs in multiple hour blocks. In competitive markets, the power provider monitors electricity use for each hour and bills customers on real-time contracts at the prevailing electricity spot market price. Real-time pricing

is expected to be the norm for most commercial customers after the transition to fully competitive markets. *See also Real-Time Metering, Time-of-Use Rates.*

Real-Time Metering or Time-of-Use Metering

In order to sell power on a time-differentiated basis (See Real-Time Pricing), meters that automatically read power use every 1 to 5 minutes are needed. Meters that record power use using a time-stamp are called time-of-use meters. Typically, use information is stored in time “buckets” every 5 to 60 minutes. The data is collected from the buckets periodically, and sometimes automatically. Another type of meter monitors and records power use continuously. Instead of storing this information, the meter is linked by a phone line or other communication system to a central computer that downloads the meter readings several times each hour. The readings are processed by a computer program to provide price and cost data consistent with the customer’s contract or the operable tariff. Real-time meters are more expensive to purchase and operate than simple energy and demand meters. However, remote meter reading is required to operate real-time meters. Remote metering reading enables a variety of suppliers to provide power to a retail customer as they no longer have a need to maintain a staff of meter readers at sites where they have customers.

Regional Transmission Groups (RTGs)

Groups formed from mergers of utility transmission operations in response to FERC Order 888, which was issued in 1996 and allowed open access to electric utility transmission systems. There was a wave of RTG formations immediately after Order 888, mostly in the western United States although ISOs soon became the preferred transmission organization. *See also Regional Transmission Organization, Independent System Operator.*

Regional Transmission Organization (RTO)

FERC Order 888, issued in 1996, brought industry attention to transmission, a technically complex and previously somewhat ignored part of the business. A series of both regulatory and institutional forums have been held to explore various futures for the transmission business. It was obvious to many transmission-owning utilities that Order 888 made transmission a business subject to scale economies; i.e., bigger would be better. The only way to make transmission systems bigger was to merge operations with other utilities under what FERC initially called Regional Transmission Groups (RTGs). The ISO superceded these in popularity and was adopted in California, Texas, and the Northeastern states, from Pennsylvania and Maryland, north to Maine. In general, ISOs have more centralization of functions than RTGs. They have more robust planning functions, are better integrated with energy markets, exercise operational control over the power grid, and have more streamlined transmission tariffs. Despite these attributes, they still lack a clear business purpose and the authority and standing to grapple with issues like transmission expansion. In addition, many of the newly formed ISOs hew to traditional utility market territories. Many market participants, as well as FERC, believe that ISOs should encompass all utilities in a broad, regional organization with clear responsibility for system reliability, including expansion. FERC and the industry have called these new institutions Regional Transmission Organizations to distinguish them from existing ISOs. FERC doesn’t believe it has authority to order utilities to join or form ISOs or RTOs except in unique situations, such as when it can require it as a condition for approval of utility mergers. It has advised Congress of the need for such authority, but Congress has yet to grant it. Nevertheless,

after witnessing the evolution of transmission since Order 888, FERC has directed all utilities to consider joining or forming an RTO and to report back to FERC by October 2000 on their decisions and plans. *See also Independent System Operator.*

Regulation

Broadly stated, a regulation is a rule or law established by the federal or state government that a company must follow. In utility terms, regulation is the act of overseeing utility operations and finances. Utility regulation is a substitute for the discipline of competition in competitive markets. Markets regulate certain business practices so they conform to the will of the market, assumed to be composed of many consumers. Markets are assumed to stimulate the offering of new products and services at optimal prices and to discipline firms that do not do so by driving them out of business. Utilities are assumed to offer services that are needs (rather than wants) that should be made available to the entire population at reasonable prices. The reasoning behind utility regulation is that the vagaries of the marketplace are thought to be too volatile to ensure a socially acceptable result, thus firms were selected to provide these services without competition. To prevent expected monopoly abuses, prices and operations are subject to regulation by a public body representing consumer interests.

Regulatory Assets

Regulatory assets are investments the utility made with an understanding from regulators that the associated costs could be recovered, even though there may be no tangible asset. The most well known example is investments in demand side management measures.

Reliability

Reliability is a catch word for providing dependable generation, transmission and distribution service. Consumers (and some regulators) confuse reliability with adequacy. Reliability involves maintenance of facilities and reserves and proper operation of facilities to maintain system operations within specified parameters (i.e., voltage, harmonics, etc.). Adequacy is related to reliability in that sufficient resources must also be provided to meet demand. If inadequate (in quantity or quality) resources are available, it is essentially impossible to operate the power system consistent with applicable standards. However, the provision of adequate resources is often a generation issue, whereas reliability is primarily a transmission operation issue. If adequate generation is not available to meet consumer demand, it won't matter that the transmission infrastructure is 100% reliable. Because generation and transmission are substitutes in some cases, a similar claim can be made for transmission assets. Namely, if the transmission system isn't expanded to keep step with demand, the fact that the existing system is 100% reliable is also beside the point. With deregulation, responsibility for adequacy and reliability are separate challenges for different participants. The power market is expected to provide adequate supplies to meet demand. Similarly, as users of the transmission grid, power suppliers are expected to pay for the construction of new transmission facilities to ensure adequate transmission capacity to get power from new resources to growing loads. Transmission owners and operators (e.g., ISOs) are expected to plan for and manage transmission demand and facilities to ensure reliable transmission of power as needed to keep pace with demand growth. This implicit division of responsibility may obscure an accountability gap. Although either new transmission elements or local generation investments can solve pending reliability concerns,

there is, at present, no obvious mechanism under deregulation to dictate a solution if market processes fail.

Renewable Portfolio Standard (RPS)

An RPS is an environmental requirement some states have adopted that specifies that a minimum fraction of generation must come from renewable resources, typically wind and solar power. Some state deregulation agreements require all power marketers to maintain this fraction; others allow marketers to trade with renewable power developers to meet the standard. For example, the state may require that all power suppliers meet an RPS of 3% by 2005. As a result, every power supplier must be able to document resources in its resource portfolio that are derived from renewable power equal to 3% of state retail power sales in 2005. These can be in the form of renewable resources owned, or output purchased from such sources. Generally, states that have an RPS requirement also plan to verify the renewable claims of power suppliers.

Renewable Power

Renewable power, often called green power, is electricity that is produced with environmentally clean power sources such as solar, wind, hydro and biomass. There are multiple definitions of renewable power although most do not include large hydropower resources and power from waste-burning facilities. Although green power is often used to mean renewable generation, this is often not the case. As a result, it is necessary to clearly specify the kind of resources included in either definition and to establish how environmental claims are verified.

Reserve Margin. See Generating Reserve.

Restructuring

Restructuring is the process of changing the structure of a utility industry from one of monopoly supplier and captive customer to one of competition among suppliers for customers. Deregulation of price and customer choice restrictions is a governmental action that allows competition. Restructuring occurs when organizations respond to the advent of competition. As such, it is self-induced. In a phrase, it is what the industry does to itself, rather than what regulators do to the industry. Typical restructuring responses include separating utilities into their separate functions -- transmission, distribution, and generation; adding new products and services; merging with other firms; and divesting assets that are not considered to be central to the firm's new business direction. *See also Deregulation.*

Retail Customer

A customer who uses the energy it purchases rather than reselling it. Sometimes the term is used to refer to residential customers.

Retail Competition

The process through which companies attempt to sell products and services to the consumers. In deregulated energy markets, competing firms will be trying to sell energy directly to customers. Absent deregulation, the local utility is required to sell energy directly to its customers but is prohibited from selling energy to retail customers outside its boundaries.

Retail Wheeling

Retail power sellers need to arrange delivery of power to retail customers using the existing transmission and distribution system. The process of transmitting electricity over transmission lines not owned by the supplier to a retail customer of the supplier is called retail wheeling. Similar transfers at the wholesale level using the bulk power grid are simply called “wheeling.” With retail wheeling, electricity consumers can secure their own supply of electricity indirectly, from a marketer or directly from the generating source. The power is then wheeled, or transmitted, for a rate that is a fixed rate or set by a utility commission. *See also Transmission Charges.*

Retailer

An energy retailer is a company authorized to resell energy to retail customers. Energy retailers are technically known as marketers but are also called suppliers. Marketers are required to be registered by state or federal agencies. Energy brokers may be lumped under this term, but they do not technically resell energy. Instead they act as facilitators of sales between owners and purchasers for which they receive a commission, like a realtor selling a house. They are not necessarily required to register with any state agency.

Rotor. See Electric Generation.

Run-of-River Hydro Plants

All dams create lakes behind them, however, some do not have a great amount of storage capacity because of the shape of the river valley and where the dams are located. One reason for this is other users of the river may not want to stop the flow of water. Dams used this way for hydropower production are called run-of-river dams. A notable example is the dams on the lower reaches of the Columbia River.

S

Schedule Coordinators (SCs)

Arrangements for transmission of power are both critically important and complicated. Accordingly, the right to schedule transmission transactions is restricted to properly trained and appropriately situated individuals or organizations. The term “schedule coordinator” comes from California. Other states and power systems have different names for this same activity, usually simply “scheduler” or “dispatcher.”

Securitization

The process of paying the local utility for stranded costs (and sometimes temporary rate discounts) through bond sales. The bonds issued through securitization are paid off over a multi-year period. As a result, repayment of these bonds reduces the savings customers could receive under deregulation.

Service Area,

The service area, also known as the franchise territory, is a specifically defined territory in which a utility has been granted exclusive rights to sell energy to retail customers. *See also Franchise.*

Shopping Credit. See Generation Charge.

Simple-Cycle Combustion Turbines. See Gas Turbines.

Slamming

Slamming is the act of changing a consumer's utility service provider without his/her knowledge or permission. This is typically achieved through some type of deceptive advertising. Slamming is common in the telephone industry. As a result of consumer complaints, the Federal Communications Commission (FCC) has fined telephone carriers with a proven history of slamming. Energy deregulation legislation often contains prohibitions against slamming in retail energy markets.

Solar Power

Solar power may use a variety of methods to produce electricity. Normally, it uses photovoltaic cells. However, power can also be produced using mirrors to concentrate sunlight to generate steam to turn turbines that produce electricity. Sometimes the solar energy is stored as heat so that power can be produced when the sun is not shining.

Source Energy. See Power Sources.

Spot Market

Short-term purchases of electricity or natural gas at current commodity market prices are called spot market purchases and the market is called a spot market. Commodity markets work on a bid and offer basis with many buyers and sellers meeting to negotiate prices in an auction type environment. Prices for commodities vary throughout the trading day, and from trading session to trading session. Prices can be fixed in other markets offering commodity deliveries at future dates. These are called futures or option contracts. Commodity markets are dominated by speculators who do not have a direct interest in the commodity they trade (they are not buying for their own use). As a result, commodity consumers have ready access to sources of supply and producers find a ready market for sales. Commodity markets are a key feature of well-developed competitive markets and are a hallmark of modern capitalism.

Spread. See Commodity Market.

Standard Offer Service

The standard offer is the price of the power that is supplied to you by your distribution company until you choose a competitive power supplier. Standard offer service is a transitional service that gives you time to learn about your options. The price of the standard offer service is set in advance, but may increase. In the early years of deregulation, standard offer service may be competitive with other competitive offers but in the longer run it is not expected to be the lowest

cost option. The standard offer rate is the price the local utility offers to customers that do not choose a new supplier.

Although the term “standard offer” is normally used to refer to a specific rate, a few states (mostly in New England) use the term to mean the imputed value of a pre-deregulation utility’s cost of generation that is subject to competition after deregulation. For example, if the pre-deregulation utility rate is 10 cents and 3 cents of that reflects the cost of generation, the “standard offer” for competitive power supplies would be 3 cents. Customers would all pay the same the post-deregulation delivery rate of 7 cents (10 cents minus 3 cents) plus the price of power, either the 3 cent “standard offer” price, or less from a competitive supplier. Obviously, competitive offers that are less than the standard offer would result in consumer savings. This New England usage contrasts with the more common usage where the “standard offer rate” would be similar to the old, pre-deregulation utility rate of 10 cents. Competitive power suppliers may provide power at prices that result in total costs below the ten cent “standard offer” rate in our example.

Standby Service

Traditionally, standby service has applied to customers that rely on power from on-site generation. In most cases, the utility charges for “standing by” to provide power in case it is needed as a form of insurance. Often this charge is so high that it is uneconomical for a facility to install new on-site generation. After deregulation, customers with on-site generation should be able to purchase back-up power from the spot market at prevailing prices. This should be significantly less than most utility stand-by rates.

Stranded Costs

Stranded costs consist of assets such as generation, power contracts, and regulatory commitments that are currently paid for by customers which may not be recoverable by the utility if customers switch to other suppliers. For example, a utility may have generating costs that are 3 cents higher because of their mortgage on new power plants. If customers of the utility find another supplier whose power is 2 cents cheaper, they may switch. If the existing utility is forced to discount its power by 2 cents to stay competitive, the 2 cents per kilowatt it loses would be a stranded cost.

Existing power plants were built by utilities to meet service requirements imposed by regulators. As a result the utilities argue they should be allowed to recover these stranded costs (the 2-cent difference in the example) from current customers. All of the deregulation agreements made thus far are allowing utilities to recover some or all of these costs through a surcharge on sales and sometimes through a bond sale, called securitization. Having established a precedent with generating costs, other parties have succeeded in attaching additional stranded cost surcharges for labor contracts, conservation programs, and other vestiges of regulation that are imperiled by deregulation. Fortunately, stranded costs end after a transition period to full competition. When stranded cost recovery ends, consumer prices are expected to fall, often by 15 to 20%. *See also Securitization.*

Stranded Investments. See Stranded Costs.

Sunk Costs or Fixed Costs

A utility's fixed costs are predominately the costs associated with plant construction. These costs are similar to a home mortgage, which must be paid regardless of use. Although utilities are allowed to recover these costs, the costs themselves are sunk costs as nothing can be done to change them.

Supplier

A supplier is a new provider of electricity as an alternative to the incumbent utility. It may be a marketer, aggregator (purchasing from a marketer), or third-party power producer. Many deregulation agreements prevent incumbent utilities from selling power directly to their former customers. As a result, those utilities that want to remain in the power sales business have to form subsidiaries.

Supplier of Last Resort

The supplier automatically provided for a customer if the customer does not choose a new supplier under deregulation. This is usually the incumbent utility. Some states require the local utility to solicit power supplies from the competitive market rather than sell its own power to customers who choose not to change suppliers. Typically, the supplier of last resort sells power at a regulated rate, called a standard offer rate. *See also Standard Offer.*

System Sale. See On-System Sale.

T

Tariff. See Rate.

Tariff Administrator. See Independent System Operator.

Therm

A unit of measuring heat that stands for 100,000 British Thermal Units (BTUs). *See also BTU.*

Time-of-Use Meter

A meter that measures how much electricity a customer uses during a specific time of the day and in total. It is more sophisticated than typical kWh meters; however, it is not as sophisticated, or expensive, as a real-time meter that records electricity use continuously and communicates these readings back to a billing computer. *See also Real-Time Metering.*

Time-of-Use Rates

Rates charged to customers based on when they use electricity during the day and how much electricity they use. The costs (and value) of generation vary on a daily and seasonal basis. Utility rates tend to average these costs, which provides customers with misleading impressions of how much power costs, especially during peak use periods. Time-of-use rates are a response to the desire by utilities and economists to correct this situation by setting rates to more accurately mirror generating costs on a daily and seasonal basis. Time-of-use rates generally divide weekdays and months into high-cost on-peak periods and low-cost off-peak periods. The

intervals in between the peak and off-peak periods are often incorporated into a third rate that is called a shoulder or mid-peak period. Use during each of these periods is captured using a special meter that records the use in each period. *See also Real Time Pricing.*

Transition Charge

The mechanism by which stranded costs continue to be paid by customers who switch to another supplier is frequently called a transition charge. Stranded costs are temporary expenses that are included as a transition charge on your electric bill after deregulation during the transition period to a fully competitive market. Stranded costs are costs that cannot be fully recovered in a competitive market. As stranded costs are recovered, transition charges will be phased out. *See also Stranded Costs and Securitization.*

Transition Costs. See Stranded Costs and Transition Charge.

Transition Period

The time period, established by deregulation legislation, during which the incumbent utility, regulators, and consumers adapt to deregulated power markets. The duration of this transition is usually tied to the period of time the utility is allowed to make the financial adjustments and can recover stranded costs through transition charges. *See also Transition Charge, Stranded Costs.*

Transmission Charges

Power consumed by retail customers can be either generated nearby or wheeled (transported) over transmission lines. Transmission charges are levied for use of the transmission system. Prohibiting access to transmission lines prevents power buyers from shopping for more economical electricity supplies. FERC recognized that fact and in the 1990s adopted a series of orders that require utilities that own transmission lines to 1) separate electricity trading functions from the operation of transmission, 2) allow any wholesale power seller or buyer access to transmission lines the utility owns, and 3) price transmission access at a uniform rate (approved by FERC) for all users, including the utility owner. Thus, all transmission users are charged the same amount.

Transmission Grid. See Grid, Transmission System.

Transmission Line

Transmission lines carry power throughout the bulk power system. Transportation of electricity across transmission lines is called “wheeling.” The distinction between transmission and distribution lines is fuzzy at best. However, only transmission lines are high-voltage lines. Distribution lines are lower voltage than transmission, but some transmission lines are also low voltage, especially those serving small, more isolated, customers. Transmission lines form a network, like the threads in a fabric, which provides multiple paths for power to flow through a large area or region. Most transmission transactions are wholesale transactions to distribution substations where voltage is reduced for use by retail customers. Transmission systems are planned and designed as an integrated system that includes specific roles for generation and loads. There are limits to how much power a transmission line can carry. As a result, plans assume that retail customers will take power out of the system and reduce the loading of transmission lines as they travel long distances. Rather than rely solely on long transmission

lines, power systems are designed so that power plants are scattered around the system. This reduces the need for more transmission lines (power that is needed by consumers can either be generated nearby or wheeled in over transmission lines). *See also Bulk Power Market, Grid.*

Transmission System. See Transmission Line.

Transparent Pricing

Implementation of price deregulation requires open markets and transparent pricing.

Transparent prices are prices that can be readily determined by market participants. If two parties enter into a private buy-sell agreement, no one else knows the agreed upon price. Buyers and sellers set transparent prices in an open environment where other interested parties can monitor the prices offered.

Turbine Generator or Combustion Turbine (CT)

All modern power generators are steam driven. The steam turns the fan-like blades of a turbine and the spinning generates electricity. The current versions of gas-fired generators utilize a combustion turbine design that is derived from jet engines. In this design, the turbine includes a compressor element that concentrates the oxygen-fuel mix to increase combustion efficiency. Contemporary combustion turbines convert about 40% of their fuel into electricity in simple cycle mode. CTs can be designed to capture and reuse the waste heat from the simple cycle to generate additional power. This design is called a Combined Cycle Combustion Turbine, or CCCT. CTs can run on oil as well as natural gas. They can also burn gas, primarily methane, derived from the gasification of coal. These plants are called Integrated Gasification Combustion Turbines, or IGCTs.

Historically, natural gas and oil have been relatively expensive generating fuels. Deregulation of natural gas markets a decade ago resulted in significantly lower prices leading to the present popularity of CTs and CCCTs. These plants are comparatively inexpensive to construct, don't require large amounts of land, and produce comparatively low levels of air and water pollutants. Nevertheless, coal is an abundant and inexpensive fuel and IGCTs may become more common in the future. *See also Gas Turbines, Electric Generation.*

U

Unbundled Services

Prior to deregulation utility bills lumped, or bundled, all charges into a charge per kWh and kW. Some utilities called out fees for items they wanted to distinguish from utility service charges, such as taxes, franchise fees, and occasionally, conservation programs. The process of deregulation requires utilities to separate, or unbundle, charges for various elements of utility service. Specifically, they are required to identify the cost of power, transmission, and often metering and billing. Frequently, post-deregulation bills include line items for stranded cost recovery, securitization costs, and public benefits fees. The remaining charges may be lumped together as distribution charges, or separated into distribution, administration, and other operating expenses. Many states are planning to expand competition to include other elements on the unbundled utility bill, with metering and billing highest on the list.

Universal Service

Utility services are deemed necessities. (That is one justification for permitting utilities to have a monopoly.) Because regulators view utilities as a necessity, they have required utility providers to make their services available to anyone who requests service. This is called universal service. Obviously, if utility rates are too high, not everyone can afford utility service. As a result, most regulators require utilities to provide a minimal level of service for a cost that is affordable to most customers. Thus, universal service has come to mean not only access to utility services (the hook-up) but allowing some minimum level of consumption at a low cost.

Usage Charge. See Kilowatt Hour Charge.

Utility

A utility can be either a private or publicly owned company that provides a commodity or service that is considered vital to the general public, such as power, water, or gas for heating. Because utility services are considered necessities, utilities are allowed to operate as monopolies and prices and service conditions are regulated by the government or subject to review by citizens.

Utility Assets. See Capital Investments.

V

Value of Service Pricing. See Cost-of-Service Pricing.

Value-Added Services. See Demand Side Management.

Variable Price or Variable Rate

A price that can change (by the hour, day, month, etc.). The cost, and value, of generation changes on an hourly basis. Variable rates or prices capture these changing costs and are a more accurate reflection of power costs than traditional fixed-cost utility rates. Some utilities have rate schedules that vary to reflect changing market conditions. After deregulation, competitive prices will vary on an hourly basis and power prices are expected to follow suit.

W**Watt**

This is a measure of the amount of electricity needed to power a device such as a light bulb. It is the primary unit of measure for electricity use. However, most electrical uses use many watts, so the most common unit of measure is 1,000 watts, or the kilowatt. Generating plants and very large customers use Megawatts (MW) as a measure. One Megawatt is equal to 1,000 kilowatts.

Wheeling

This is the process of transporting a utility commodity (electricity, natural gas, or water) across an area through wires or pipes without using it. When a utility wheels power across the transmission grid, its purpose is to get the power from one place to another, rather than to distribute the power to customers. The term is most often used to refer to the transportation of a commodity for a third party across another utility's system. For example, if utility A buys power from a power plant on the other side of neighboring utility B, it may request that utility B wheel the power across its system to utility A. Utility A expects to receive the amount of power on its end that it purchased from the power plant. In point of fact, the wheeling process consumes some natural gas or electricity. This consumption is called a loss. Electrical losses are due to line resistance. Natural gas losses are due to use of gas in the pipeline as fuel to run the compressors along the pipeline that force the gas to flow. Historically, electric utilities and pipeline companies have been unwilling to allow third parties to use their systems to move commodities purchased from other commodity producers. This stifled the development of fully competitive commodity markets and increased commodity prices. In the 1990s the FERC ordered both natural gas pipeline companies and electric utilities to wheel gas and power for wholesale buyers and sellers of those commodities. These orders resulted in increased competition in commodity markets, increased wheeling transactions, and lower commodity prices.

Wholesale

This is the sale of a commodity (such as electricity) in quantity for resale purposes. The distinction between wholesale and retail transactions is of interest primarily for regulatory purposes. Wholesale transactions often involve trade between parties in different states. As a result, wholesale transactions are considered interstate commerce and fall under the jurisdiction of the federal government, not the states. The primary regulator of wholesale transactions is FERC. In contrast, retail transactions occur within state boundaries and are the jurisdiction of state agencies. The exception for electricity is the state of Texas, which is electrically isolated from the rest of the country, so virtually all wholesale transactions occur within the state. Accordingly, the state of Texas retains jurisdiction. Similarly, natural gas that is produced and transported wholly within a gas-producing state is also exempt from FERC jurisdiction. There are several states that have intra-state (as opposed to interstate) gas pipelines. FERC took the lead in deregulating both the natural gas and electricity markets. This resulted in some very large natural gas customers, called non-core customers, gaining direct access to wholesale gas markets. Many industrial firms would like similar access to wholesale electricity markets, but those desires have been frustrated by FERC to date. Some large customers can become true wholesale customers through petitions to FERC or local regulators. However, the standards are very strict. Generally, the customer must own and operate a distribution system similar to a retail utility and use that system to resell utility services to third parties for a fee that includes distribution charges, just like a utility. Customers with wholesale status are able to avoid paying some fees that may be levied by state regulators. *See also Bulk Power Market.*

Wind Power

This is the use of wind to spin a turbine to generate electricity. Wind as slow as 5 mph can produce electricity. Isolated wind turbines were common in rural areas, especially in the Great Plains states, in the 1930s and '40s. Wind power today is a large-scale affair with multiple turbines being located in a wind farm. Wind farms produce power on a similar scale to conventional generating plants, namely 10s of megawatts. Although wind power is pollution free, the wind blows intermittently. Wind conditions are only right for wind power 30 to 40% of the time. Nevertheless, wind power is the most rapidly developing new power resource. The costs of wind power have declined significantly over the last decade, although not as fast as those of conventional generation. Still, wind power today is cheaper than power from nuclear plants was in the early 1980s.

Wires Charge

A broad term that refers to charges levied on power suppliers or their customers for the use of transmission or distribution wires to deliver electricity. Transmission and distribution use fees are obvious wires charges. However, regulators use the wires charge mechanism to collect a variety of other fees not directly related to power delivery, including stranded costs, payments for securitized debt, taxes, and franchise fees, as well as for funding low-income and public benefits programs. *See also Access Charge.*

