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2010 340 pp ISBN 978-0470-48418-0

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An Overview of Technology, the Marketplace, and Government Regulation

Second Edition

JACK CASAZZA
FRANK DELEA

IEEE Press Understanding Science & Technology Series

IEEE

IEEE Press

WILEY

A JOHN WILEY & SONS, INC., PUBLICATION

IEEE Press
445 Hoes Lane
Piscataway, NJ 08855

Library of Congress Cataloging-in-Publication Data:

Casazza, John.
Understanding electric power systems : an overview of the technology and the marketplace / Jack Casazza, Frank Delea.—2nd ed.
p. cm.
Includes bibliographical references.
ISBN 978-0-470-48418-0 (pbk.)
1. Electric power systems. 2. Electric utilities. 3. Electric power. I. Delea, Frank. II. Title.
TK1001.C386 2010
621.319'1—dc22 2009045958

Printed in the United States of America.

10 9 8 7 6 5 4 3 2 1

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PREFACE TO THE SECOND EDITION

THIS VOLUME IS THE SECOND edition of a text originally published in 2003. Since its publication, significant changes have, and continue to, impact the electric utility industry including:

- The 2003 northeast U.S. blackout
- New energy laws and a large number of FERC regulations implementing these laws
- A change in FERC's role in overseeing the industry's reliability rules and practices
- NERC's role in establishing these rules and in monitoring compliance
- The 2009 Economic Stimulus package
- Concerns about global warming and efforts to limit the utility industry's contribution to greenhouse gases

This edition addresses these issues. As Joseph C. Swidler, former Chairman of the Federal Power Commission [predecessor of the Federal Energy Regulatory Commission (FERC)] often stated: "There are many disagreements about the best electric power policy for the United States, but there is no disagreement [that] it is often being established without adequate analyses." Government and business decisions on electricity supplies often fail to recognize how power systems work and the uncertainties involved. Those involved do not always mean the same thing although they use identical words. Incorrect assumptions have been made about the operation of the electric system and continue to be made based on the operation of telephone systems, gas systems, and other physical systems that are not applicable to electric power systems.

The purpose of this book is to help those in government, business, educational institutions, and the general public, have a better understanding of electric power systems, institutions, and the electric power business.

The first edition was used for instructional purposes in many courses for electrical engineers who were not power systems engineers, for lawyers, accountants, economists, government officials, and public interest groups. Since its publication, technological and institutional changes have occurred. A major change has been the drastic increase in the government's role in the electric power industry, changing from emphasis on price regulation to an emphasis on increased control of planning, operation, design, and control of the system and the new technologies being developed. This second edition reflects this and other changes.

In recent years, the U.S. Congress has enacted a series of omnibus energy acts in response to three national imperatives:

1. Establishing a wholesale market for electricity while maintaining a reliable electric supply system
2. Reducing the country's reliance on imported oil
3. Reducing the country's contribution to global warming by reducing reliance on carbon-based fuels

The following chapters lay the background for each of the three imperatives in order that the various initiatives might be more clearly seen. We then describe various aspects of these acts and discuss their impacts on the electric power industry, including its regulatory framework, the entities involved, and the technologies used and under development. The difficulty lies in bringing some focus to a moving target. For example, reliability and market issues are being addressed, whereas the underlying structure of the industry remains in flux. Many of the changes relating to the entities involved in the industry are also addressed, including:

- New roles for FERC, DOE, and NERC
- Consolidations of old-line utilities, the newer power marketing companies, RTOs/ISOs, and regional reliability councils
- New ownership interests including investment bankers, foreign investors, venture capitalists, and entrants seeking new business opportunities in generation, transmission, distribution, and customer service

- Trade organizations/lobbying arms that have been started to seek public support of the various entities

The book covers electric power systems, their components (generation, transmission, and distribution) electricity use, electric system operation, control and planning, power system reliability, government regulation, utility rate making, and financial considerations. It is based on the following "seven networks":

1. Physical
2. Fuel/energy
3. Money
4. Information,
5. Communication and control
6. Regulatory
7. Business

These are all interconnected in the provision of electric power. It provides the reader with an understanding of the equipment involved in providing electric power, the functioning of the electric power system, the factors determining the reliability of service, the factors involved in determining the costs of electric power, and many other technical subjects. It provides the engineer with background on the institutions under which power systems function. It can be used as a classroom text, as well as a reference for consultation. Although a book of this length cannot provide in-depth discussions of many key factors, it is hoped that it provides the broad understanding that is needed.

The Internet has made available many new and valuable publications and information sources that were used in the preparation of this edition. References are provided for those who wish to pursue important points further. The index facilitates the location of background material as needed. We welcome comments, suggestions, additional information, and corrections, and hope you, your company, and all consumers benefit from the book.

Jack Casazza
Frank Delea

Springfield, Virginia
Roswell, Georgia
September 2009

ACKNOWLEDGMENTS

WHEN REVISING A TEXT COVERING the wide range of topics as we have in this book, the assistance of a number of individuals cannot be overstated. We especially want to thank Tom Schneider for his valuable suggestions concerning the organization of this complex and varied material, and for his input relating to generation and storage. Helpful comments and suggestions were also provided on NERC matters by David Nevius of NERC, on FERC matters by Lynn Hargis, on fuel issues by Jim Francher, on T&D issues by Charles L. Rudasill, Jr. (retired from Dominion Virginia Power), and for comments on information technology by Stan Klein. Any errors that may have crept into the text in these areas are solely the responsibility of the authors. We also want to thank Irene Cunnane for her help in assembling the final manuscript.

Above all, we want to acknowledge our wives, Madeline and Irene. Their support, encouragement, and, yes, understanding as we locked ourselves away writing for hours on end was immeasurable.

J. C.
F. D.

CHAPTER 1

BENEFITS OF ELECTRIC POWER AND A HISTORY OF THE ELECTRIC POWER INDUSTRY

1.1 SOCIETAL BENEFITS OF ELECTRICITY

Electric power is one of the mainstays of our lives and the life of our nation. It differentiates advanced societies from third world nations. It touches almost every facet of our lives: our homes, our businesses, our schools, our transportation, and our leisure time. It is there when we are born, and it is there when we die. Think of the impact on our lives if we were not able to watch our favorite TV shows, use our home computers, heat and cool our homes, refrigerate our food, wash our clothes or our dishes, or read at night. Yet most people take it for granted, except during those relatively rare times when it is unavailable or when we receive our electric bills and note that the charges have suddenly and unexplainedly increased.

We know we have power outlets in our homes and businesses and we may notice the distribution wires running along our streets or if we pass high-voltage transmission towers, but many of us do not know how the whole system works. Some of us are affected because we live close to new or proposed electric power facilities, generating plants, or transmission lines and substations. Some may have concerns about the economic or environmental effects of producing electricity.

The National Academy of Engineering has described the development of the national electric power system as the greatest engineering achievement of the 20th century. It has involved legions of electrical, civil, mechanical, nuclear, software, and environmental engineers working for utilities and manufacturers. It also required individuals involved in everything from meter reading, to construction, operation, and maintenance of the power plants and the transmission and distribution lines, and to specialists in accounting, finance, customer relations, public affairs, and even law. Unfortunately, electric power is not a topic covered in our schools and is barely covered in our media. Even individuals who work for utilities may not know the "big picture" outside of their specialties. Decisions are often made about electric power issues with little or no input from the general public and little or no understanding of the technical and economic issues by lawmakers.

The electric industry is large and complex, involving technical, business, and governmental aspects. It cannot be viewed or understood unless one is also familiar with the regulatory environment in which it operates. This book attempts to inform its readers so that they may understand the continuing discussions and debates about the industry and its future and may be able to participate and have their own views heard.

1.2 ORIGIN OF THE INDUSTRY

The electric utility industry can trace its beginnings to the early 1880s. During that period, several companies were formed and installed water-power-driven generation for the operation of arc lights for street lighting, which was the first real application for electricity in the United States. In 1882, Thomas Edison placed into operation the historic Pearl Street steam-electric plant and the pioneer direct current distribution system by which electricity was supplied to the business offices of downtown New York. By the end of 1882, Edison's company was serving 500 customers that were using more than 10,000 electric lamps. The early Edison systems delivered the electricity by using low-voltage direct current (DC).

Satisfied with the financial and technical results of the New York City operation, licenses were issued by Edison to local businessmen in various communities to organize and operate electric lighting companies.[1] By 1884, twenty companies were scattered in communities in Massachusetts, Pennsylvania, and Ohio; in 1885, thirty-one; in 1886, forty-eight; and in 1887, sixty-two. These companies furnished energy for lighting incandescent lamps, and all operated under Edison patents.

Two other achievements occurred in 1882: a water-wheel-driven generator was installed in Appleton, Wisconsin; and the first transmission line was built in Germany to operate at 2400 volts direct current over a distance of 37 miles (59 km).[2] Motors were introduced and the use of incandescent lamps continued to increase. By 1886, the DC systems were experiencing limitations because they could deliver energy only a short distance from their stations since their voltage could not be increased or decreased as necessary. In the United States, the use of alternating current (AC) was championed by George Westinghouse and Nikola Tesla. In 1885, a commercially practical transformer was developed, which allowed the development of an AC system. A 4000 volt AC transmission line was installed between Oregon City and Portland, 13 miles away. A 112 mile, 12,000 volt, three-phase line went into operation in 1891 in Germany. The first three-phase line in the United States (2300 volts and 7.5 miles) was installed in 1893 in California.[3] In 1897, a 44,000-volt transmission line was built in Utah. In 1903, a 60,000-volt transmission line was energized in Mexico.[4]

In this early AC period, frequency had not been standardized. In 1891, the desirability of a standard frequency was recognized and 60 Hertz (Hz)[5] was proposed. For many years 25, 50, and 60 Hz were standard frequencies in the United States. Much of the 25 Hz was used for railway electrification and has been retired over the years. The City of Los Angeles Department of Water and Power and the Southern California Edison Company both operated at 50 Hz, but converted to 60 Hz at the time that Hoover Dam power became available, with conversion completed in 1949. The Salt River Project was originally a 25 Hz system; most of it was converted to 60 Hz by the end of 1954 and the balance by the end of 1973.[6]

[1]Homer M. Rustebakke, 1983, *Electric Utility Systems and Practices,* 4th ed., Wiley.
[2]Ibid.
[3]Ibid.
[4]Ibid.
[5]One hertz is equal to one cycle per second.
[6]Rustebakke, op. cit.

Over the first 90 years of its existence, until about 1970, electric consumption doubled about every ten years, a growth of about 7% per year. In the mid-1970s, due to increasing costs and serious national attention to energy conservation, the growth in the use of electricity dropped to almost zero. Today, growth is forecasted at about 1% per year until 2030.[7]

The growth in the utility industry has been related to technological improvements that have permitted larger generating units and larger transmission facilities to be built. In 1900, the largest turbine was rated at 1.5 MW. By 1930, the maximum size unit was 208 MW. This remained the largest size during the Depression and war years. By 1958, a unit as large as 335 MW was installed, and two years later in 1960, a unit of 450 MW was installed. In 1963, the maximum size unit was 650 MW and in 1965 the first 1000 MW unit was under construction. Unit sizes continued to grow, with generating units now as large as 1425 mW.[8]

Improved manufacturing techniques, better engineering, and improved materials allowed for an increase in transmission voltages in the United States to accompany the increases in generator size. The highest voltage operating in 1900 was 60 kV. In 1923, the first 220 kV facilities were installed. The industry started the construction of facilities at 345 kV in 1954, in 1964 500 kV was introduced, and 765 kV was put in operation in 1969 and remains as the highest transmission voltage in the United States.[9] Larger generator systems required higher transmission voltage; higher transmission voltage made possible larger generators.

These technological improvements increased transmission and generation capacity at decreasing unit costs, accelerating the high degree of use of electricity in the United States. At the same time, the concentration of more capacity in single generating units, plants, and transmission lines had considerably increased the total investment required for such large projects, even though the cost per unit of electricity had come down.

[7]Energy Information Agency (EIA), *Annual Energy Outlook,* 2009.

[8]The vast majority of the approximately 65 units larger than 1000 mW are nuclear units constructed in the 1970s and 1980s. Since then, the largest of the new capacity additions have been significantly smaller. For example, the Energy Information Agency's list of new capacity for the period September 2007–August 2008 indicates the largest unit was 558 mW.

[9]Work on UHV (voltages 1000 kV or higher) is underway in China, India, and Brazil. The State Grid Corporation of China is working on a 1000 kV UHV transmission project connecting North and Central China.

Not all of the pioneering units at the next level of size and efficiency were successful. Sometimes, modifications had to be made after they were placed in operation; units had to be derated because the technology was not adequate to provide reliable service at the level intended. Each of these steps involved a risk of considerable magnitude to the utility, first to install a facility of a new type or a larger size or a higher transmission voltage. Creating new technologies required the investment of considerable capital that in some cases ended up being a penalty to the utility involved. To diversify these risks, companies began to jointly own power plants and transmission lines so that each company would have a smaller share and, thus, a smaller risk, in any one project. The sizes of generators and transmission voltage levels evolved together, as shown in Figure 1-1.[10]

A need for improved technology continues. New materials are being sought in order that new facilities can be more reliable and less costly. New technologies are required in order to minimize land use, water use, and the impact of the industry on the environment. The manufacturers of electrical equipment continue to expend considerable sums to improve the quality and cost of their products. Unfortunately, funding for such research by electric utilities through the Electric Power Research Institute (EPRI)[11] continues to decline.

1.3 THE DEVELOPMENT OF THE NATIONAL ELECTRIC POWER GRID[12]

Electric power must be produced at the instant it is used. Needed supplies cannot be produced in advance and stored for future use. At an early date, those providing electric power recognized that peak use for one system often occurred at a different time from peak use in other systems. They also recognized that equipment failures occurred at different times in various systems. Analyses showed significant economic benefits from interconnecting systems to pro-

[10]J. A. Casazza, 1993, *The Development of Electric Power Transmission—The Role Played by Technology, Institutions, and People,* IEEE Case Histories of Achievement in Science and Technology, Institute of Electrical and Electronic Engineers.

[11]See Chapter 19 for a discussion of EPRI, the industry's research organization.

[12]Casazza, op. cit.

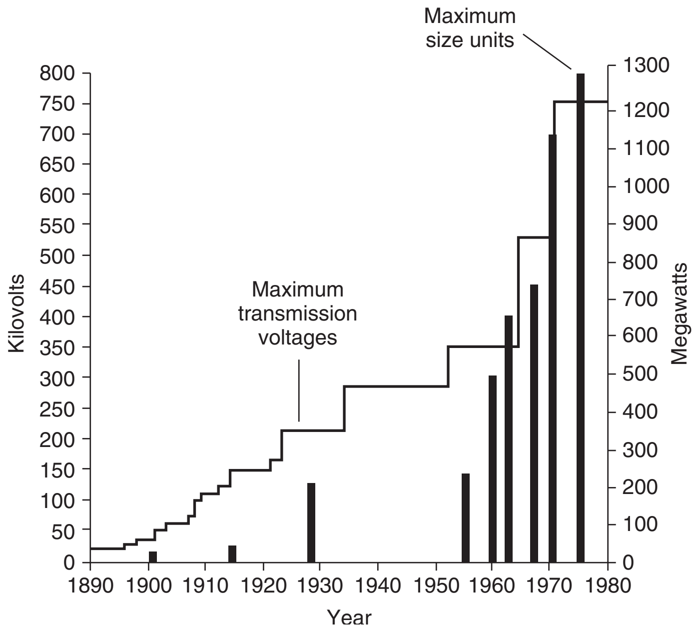

Figure 1-1. Evolution of generator sizes and transmission voltages.

vide mutual assistance; the investment required for generating capacity could be reduced and reliability could be improved. This lead to the development of local, then regional, and, subsequently, three transmission grids that covered the United States and parts of Canada. In addition, differences in the costs of producing electricity in the individual companies and regions often resulted in one company or geographic area producing some of the electric power sold by another company in another area. In such cases, the savings from the delivery of this "economy energy" were usually split equally among the participants. Figure 1-2 shows the key stages of the evolution of this grid. Figure 1-3 shows the five synchronous power supply areas currently existing in North America.

The development of these huge areas in each of which all generation is connected directly and indirectly by a network of transmission lines (the grid) that allows the generators to operate in synchronism presents some unique problems because of the special nature of electric power systems. Whatever any generator or transmission line in one area does or does not do affects all other generators and transmission lines in the same area, those nearby

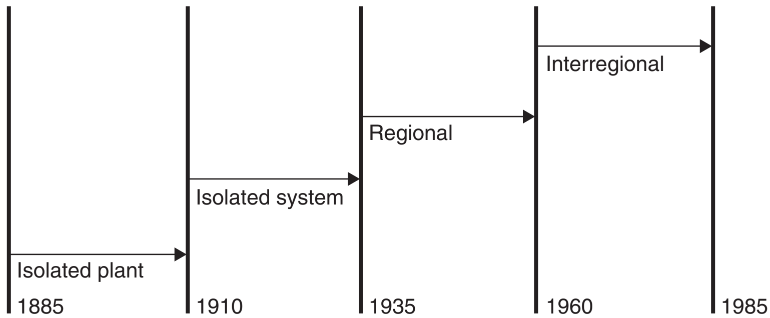

Figure 1-2. Key stages in the evolution of the grid in the United States.

more significantly and those distant to a lesser degree. In the Eastern Grid (or Interconnection), the loss of a large generator in Chicago can affect generators in Florida, Louisiana, and North Dakota. Decisions on transmission additions can affect other systems many hundreds of miles away. This has required the extensive coordination in planning and operation between participants in the past. New procedures will be needed in the future.

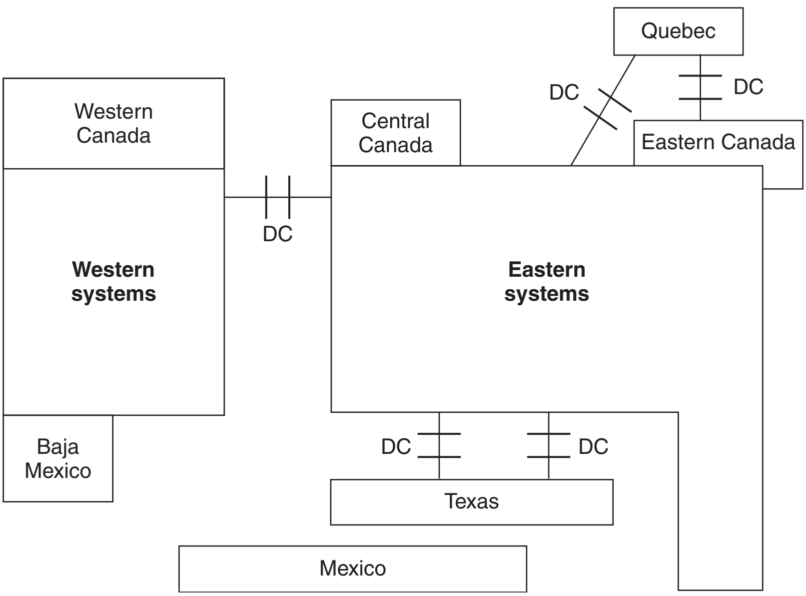

Figure 1-3. Synchronous power grids in North America.

As stated by Thomas P. Hughes of the University of Pennsylvania in the September 1986 issue of *CIGRE Electra*:[13]

> Modern systems are of many kinds. There are social systems, institutional systems, technical systems, and systems that combine components from these plus many more. . . . An example of such a technological system . . . is an electric power system consisting not only of power plants, transmission lines, and various loads, but also utility corporations, government agencies, and other institutions. . . . [P]roblems cannot be neatly categorized as financial, technical, or managerial; instead they constitute a seamless web. . . . [E]ngineering or technical improvements also require financial assistance to fund these improvement(s) and managerial competence to implement them.

1.4 "THE GOLDEN AGE"

The golden age of electric utilities was the period from 1945 to 1965. During this period, there was exponential load growth accompanied by continual cost reductions. New and larger plants were being installed at a continuously lower cost per kilowatt, reflecting economics of scale. Improvements in power plant efficiency were being obtained through higher temperatures and pressures for the steam cycle, which lowered the amount of fuel required to produce a kilowatt hour of electric energy. New generating plants were being located at the mine mouth, where coal was cheap, and power was transmitted to the load centers. This required new, higher voltage transmission lines since it had been found that transmitting electric energy, called "coal by wire," was cheaper than the existing railroad rates.

The coordination between utilities was at a maximum. The leaders of the industry involved in planning the power systems saw the great advantage of interconnecting utilities to reduce capital investments and fuel costs. Regional and interregional planning organizations were established. The utilities began to see the advantage of sharing risk by having jointly owned units.

On the analytical side, improved tools were rapidly being developed. Greatly improved tools for technical analysis, such as

[13] J. A. Casazza, 1993, *The Development of Electric Power Transmission—The Role Played by Technology, Institutions, and People,* IEEE Case Histories of Achievement in Science and Technology, Institute of Electrical and Electronic Engineers.

computers, began to appear, first as analog computers and then as digital computers. At the same time, the first corporate financial models were developed for analyzing future plans for possible business arrangements for joint projects, of costs to the customers, for the need for additional financing, and the impact on future rates.

All of these steps reduced capital and fuel costs, which resulted in lower rates to customers. Everyone was happy. The customers were happy because the price of electricity was going down. Investors were happy because their returns on investments and the value of their stock were increasing. System engineers were happy because they were working on interesting and challenging problems that were producing recognized benefits, and their value to the utility organizations was increasing. Finally, business managers were happy that they were running organizations that were functioning smoothly and were selling their product to satisfied customers.

Blackouts and the Reliability Crisis

The first blow to this "golden age" was the blackout of New York City and most of the Northeast in 1965, which was caused by events taking place hundreds of miles away at Niagara Falls. The government's reaction was immediate. Joseph C. Swidler was then Chairman of the Federal Power Commission. On order from President Johnson, he set up investigative teams to look into the prevention of future blackouts. As a result, they wrote an excellent report called *Prevention of Power Failures,* which is a classic to this day.[14] This report and a number of subsequent blackouts lead to increasing attention by Congress and the Federal regulatory agencies—the Federal Power Commission (FPC), now called the Federal Energy Regulatory Commission (FERC),[15] and the Department of Energy (DOE)[16]—to questions of reliability and increasing study. As an alternate to additional legislation, the industry recognized the need to govern itself and formed the National Reliability Council (NERC)[17] and the Electric Power Research Institute

[14]Federal Power Commission, *Prevention of Power Failures,* Volume I, Report to the Commission, Washington, D.C., July 1967.
[15]FERC, The Federal Energy Regulatory Commission, is the successor to the Federal Power Commission (FPC). See Chapter 14 for a discussion of FERC.
[16]After its formation in 1977. See Chapter 14 for a discussion of the DOE.
[17]See Chapter 10 for a discussion of NERC.

(EPRI). Formal regional reliability criteria were developed, reliability conditions monitored, and major funds contributed to develop new technology.

Notwithstanding these criteria, the start of the twenty-first century was marked by the largest blackout the United States has ever experienced. Influenced by the blackout, Congress passed the Energy Policy Act of 2005 (EPAct05), including a provision that adherence to nationwide planning and operating standards be mandatory and providing for an expanded role for FERC in oversight of the planning and operation of the industry's operation in the name of reliability.

The Environmental Crises—The Shift to Low-Sulfur Oil

Starting shortly after the reliability crisis, and overlapping it considerably, was the environmental crisis. Both the public and the government became concerned about air quality, water quality, and the effect of electricity production on the environment. New environmental legislation was passed. These concerns made the siting of new power plants very difficult. The power industry began installing nuclear units (which essentially have no exhaust), converting some of the existing coal-burning units to low-sulfur oil, providing electrostatic precipitators to filter out particulate emissions, installing scrubbers to remove sulfur combustion products, and installing cooling towers so rivers would not heat up. All of these steps helped meet new government environmental requirements but significantly increased capital costs and fuel costs.[18]

The Fuel Crisis—The Shift from Oil

While these changes and additions were still underway, the industry was overtaken by another crisis. In 1973, the OPEC organization stopped all delivery of oil to the United States. This raised serious questions about plans to reduce air pollution by converting existing coal-burning units to oil. Plans were cancelled to convert generation to oil (at a considerable financial penalty). Huge increases in the price of fuel occurred.

[18]In the early 2000s, concerns about perceived global warming and the effect of carbon-based fuels are driving measures to reduce carbon emissions.

The Financial Crisis

At the same time, the country found itself in an inflationary spiral; the cost of money rose to double-digits rates. All utility costs increased rapidly, requiring large rate increases. Because of the political impacts of such rate increases, many state regulatory commissions rejected these requests, thus exacerbating the financial problems of utilities. The depressed economy and rising costs of electricity dampened electric sales and load growth. The financial crisis resulted in a period of increasing costs, declining revenue, the lack of load growth, and large amounts of generating capacity under construction that would not be needed as soon as originally projected. Utilities were forced to cancel construction of projects already underway, resulting in large cancellation payments.

In 1979, a major accident occurred at the Three Mile Island Nuclear Plant in Pennsylvania. In response, the Nuclear Regulatory Commission issued orders greatly increasing the safety standards for nuclear power plants and requiring major design modifications. In combination with the high levels of inflation being experienced at the same time, massive overruns occurred in the cost of nuclear plants still under constructions. The service dates for many plants were delayed, in some cases for many years. These delays amplified the utilities' financial crisis even further because there was an appreciable investment in these partially completed plants on which earnings were required, even though the plants were not operating and producing any electricity. Ten-fold cost increases were experienced by many of these plants. Some units that were built were never run. As a result of the cost issues and the greatly increased public concern over the safety of nuclear plants, proposals to construct new nuclear generation plants were brought to a standstill. There have been no new nuclear power plants built in the United States for many years, although the nuclear industry continued to flourish overseas. Recent Federal legislation seeks to reinvigorate the nuclear option,[19] primarily as an alternative to imported oil and as a noncarbon-emitting source of electricity, although the issue of nuclear waste disposal remains to be solved.[20]

[19]See discussion in Chapter 6 of new nuclear technologies.

[20]"President Obama's proposed budget all but kills the Yucca Mountain project, the controversial Nevada site where the U.S. nuclear industry's spent fuel rods were to spend eternity. There are no other plans in the works, so for now the waste will remain next to Zion and 103 other reactors scattered across the country." See *Los Angeles Times,* March 11, 2009 article by Michael Hawthorne.

The Legislative and Regulatory Crisis

At about the same time, the Federal Government had become very chaotic and unpredictable in the regulations it issued. Some believed that paying to reduce peak power consumption was more economical than building new generating and transmission capacity. This concept has been called least-cost, demand-side, or integrated resource planning.

The Public Utility Regulatory Policies Act (PURPA) legislation, passed in 1978, prescribed the use of "avoided costs" for determining payments to independently owned cogenerators and qualifying facilities (QFs), such as low-head hydro and garbage burners. These "avoided costs" were the alternate utility costs for producing electricity based on the alternates available to the utility system. They were based on estimates of future costs, made by state regulators, which turned out to be much higher than the actual costs that occurred, primarily because of the significant overestimates of the future price of fuel. Unfortunately, many utilities were required to sign long-term contracts for purchased energy reflecting these cost estimates. The avoided-cost approach led to excessive payments to some cogenerators and other qualifying facilities. Subsequently, some utilities had to make very large payments to the plant owners to cancel such contracts or to purchase the plants.

The next step by some state regulatory commissions was the proposal and, in some cases, the adoption, of competitive bidding procedures for new generators.

The Energy Policy Act of 1992 (EPAct92), FERC Orders 888 and 889, and various other FERC orders and notices followed, all seeking to foster a competitive wholesale market for electricity. One of the approaches implemented in some areas called for competitive bidding for the provision of the electricity needed each hour. It required all bidders whose proposals were accepted to be paid the highest bid accepted for the hour even though their proposal was lower. Proponents of the industry restructuring claim that restructuring has reduced costs to consumers. This claim is not accepted by all observers. Additionally, the rapid development of expanded wholesale markets with many new participants resulted in an increased level of complexity in operations, not always matched by the development and deployment of the necessary hardware, software and operational control necessary to maintain reliability. Rapidly rising costs, declining reliability, and developing procedures for manipulating electricity prices, have all increased concern and scrutiny of the electric power industry.

The Energy Policy Act of 2005 (EPAct05) and subsequent orders by FERC greatly increased the role of the federal government in the oversight of the planning and operation of the industry.

1.5 GLOBAL WARMING CRISIS AND CONCERNS ABOUT CARBON EMISSIONS

Scientists and environmentalists have been sounding a warning that the earth is becoming warmer and that the potential effects on the world's population and ecosystems would be a disaster. Although recent data indicates that the earth has, on average, experienced a warming trend, the argument for the existence of long-term global warming is still contentious. Data on the earth's temperature can be found at the National Oceanic and Atmospheric Administration (NOAA) National Climatic Data Center.[21]

Irrespective of the validity of either the position of the global warming proponents or those who argue against global warming, a groundswell of political/environmental opinion is seeking to determine if the activities of mankind have contributed to or are causing the temperature increase and what steps could be taken to mitigate or eliminate any such causes. Proposals to reduce greenhouse gas emissions, including those of the utility industry, are being considered by Congress as this book goes to press.[22]

1.6 RESTRUCTURING, COMPETITION, AND THE INDUSTRY OWNERSHIP STRUCTURE

At the turn of the twentieth century, the United States was dotted with approximately 5000 isolated electric plants, each servicing a small area. Entrepreneurs bought these systems to form larger systems. It was easier to raise cash and savings could be obtained by coordinating generation, transmission, and the distribution system development over a wider region.

In the 1920s and early 1930s, large utility holding companies were formed. Practices in the electric power industry that lead to

[21]http://www.ncdc.noaa.gov/oa/climate/globalwarming.html#q3.
[22]See Chapter 5 for a discussion of this issue.

Table 1-1. Installed net summer generation capacity by producer type, Summer 2007

Producer type	Number of generators	Net summer capacity (mW)
Electric utilities	9,237	571,200
Independent power producers	5,138	357,278
Subtotal	14,375	928,478
Customer owned	646	37,254
Commercial	635	2,312
Industrial	1,686	26,844
Subtotal	2,967	66,410
Total all sectors	17,342	994,888

Source: EIA.

additional economies of scale often lead to opportunities for major financial abuses. The concentration of economic power in fewer and fewer organizations, through highly leveraged purchases of companies, led to Congress passing the Public Utility Holding Company Act of 1935 (PUHCA).[23]

Over more than 100 years, the ownership of generation plants and transmission and distribution systems has evolved. For many years, generation was owned by investor-owned companies; rural electric cooperatives; various nonfederal governments, such as municipals, states, irrigation districts, and so on; and a number of Federal Authorities. Since the early 1990s, private ownership of generation has greatly increased. Table 1-1[24] shows the ownership of U.S. generating facilities. In 2007, independent power producers owned 35.9% of the capacity, up from 25.8% in 2000.

Transmission systems are still owned by the same entities as above although operational control has been ceded to independent third parties such as ISOs and RTOs. A few merchant transmission lines have been built and others are proposed.

[23]PUHCA was repealed by the Energy Policy Act of 2005, discussed in Chapter 13.

[24]In the first edition of this text, additional information was provided in more detail on ownership interests. Unfortunately, the Energy Information Agency no longer publishes reports with the additional detail.

CHAPTER 2

THE ELECTRIC POWER SYSTEM

This chapter gives an overview of the electric power system. The electric power industry delivers electric energy to its customers that they, in turn, use for a variety of purposes. Although power and energy are related,[25] customers usually pay for the energy they receive, not for the power.

An electric power system is comprised of the following parts:

- The customers[26] who require the electric energy and the devices in which they use the electric energy: appliances, lights, motors, computers, industrial processes, and so on
- The sources of the electric energy: electric power plants and electric generation systems of various types and sizes
- The delivery system by which the electric energy is moved from the generators to the customers

Taken together, all of the parts that are electrically connected or intertied operate in an electric balance. The technical term used to describe the balance is that the generators operate in synchronism

[25]See Chapter 3 for explanation of power and energy.

[26]Some have questioned inclusion of customers as a part of the power system. The authors feel that the magnitude, location, and electrical characteristics of customer load are as important as those of generators. Additionally, demand-side management and distributed generation also impact both the electrical and commercial operation.

with one another. Later, we will discuss how this concept of being in synchronism applies in the United States and Canada.

2.1 THE CUSTOMERS

Customer usage is typically referred to as customer demand, customer load, or "the load." The peak usage, usually measured over an hour, a half hour, or 15 minutes (peak demand) is measured in either kilowatts or megawatts. The energy used by a typical residential or small commercial customer is measured in kilowatt-hours and that used by larger customers in megawatt-hours.

Industry practice has been to group customers by common usage patterns. Typically, these customer classes (or groups) are:

- Residential customers
- Commercial customers
- Industrial customers
- Governmental customers
- Traction/railroad customers

A reason for delineating customer types is to recognize the costs that each customer class causes in the provision of electric service since different customer classes have different usage patterns with differing impacts on the capital and operating costs. In a regulated environment, in which customers are charged for their usage of electricity based on the cost of that supply, these classifications allow different menus of charges (rates) to be developed for each customer class.

In order to establish schedules of charges (rates) for each class of customer, utilities perform studies of the contributions of the various classes to the utility's costs. These are called cost-of-service studies.

Analyzing different customer types also facilitates forecasting changes in customer's electric requirements. These forecasts are required for long-range planning and short-range operating purposes.[27]

Individual customer requirements vary by customer type and by hour during the day, by day during the week, and by season. For example, a residential customer's peak hour electricity con-

[27]See Chapter 4.

sumption will normally occur in the evening during a hot summer day when the customer is using both air conditioning, lighting, and perhaps a TV, computer, or other appliances. A commercial customer's peak hour consumption might also occur during the same day but during afternoon hours when workers are in their offices.

The time of day when a system, company, or geographic area peak occurs depends on the residential, commercial, and industrial customer mix in the area. The aggregate customer annual peak demand usually occurs during a hot summer day or a cold winter day, depending on the geographic location of the region and the degree of customer use of either air conditioning or electric heating. The electric system is built to meet the maximum aggregate system and local area peak customer demand for each season.

Diversity refers to differences in the time when peak load occurs. For example, if one company's area is heavily commercial and another's is heavily residential, their peaks may occur at different times during the day or even in different seasons. This timing difference gives the supplying company the ability to achieve savings by reducing the total amount of capacity required.

The types of electric devices customers use also have an important bearing on the performance of the electric system during times of normal operation and times when electrical disturbances occur, such as lightning strikes, the malfunctioning and loss of generating resources, or damage to parts of the delivery system. Some types of customer equipment, such as large motors, can require that devices be installed to provide extra support to maintain the power system's voltage.

The electric system has metering equipment to measure and record individual customer electric usage (except for street lighting) and systems to bill and collect appropriate revenues. For most customers, the meters measure an aggregate energy usage. For larger customers (usually commercial and industrial), meters also are used that record peak demand.

2.2 SOURCES OF THE ELECTRIC ENERGY—GENERATION

There are a number of ways to produce electricity, the most common commercial way being the use of a synchronous generator driven by a rotating turbine. The combination is called a turbine–generator.

The most common types of turbine–generators are those in which a fossil fuel is burned in a boiler to produce heat to convert water to steam, which drives a turbine. The turbine is attached (coupled) to the rotating shaft (armature or rotor) of a synchronous generator in which the rotational energy is transformed to electrical energy. In addition to the use of fossil fuels to produce the heat required to change the water to steam, there are turbine–generators that rely on the fission of nuclear fuel to produce the heat. Other types of synchronous generators are those in which the turbines are driven by moving water (hydro turbines) and gas turbines that are turned by the exhaust of a fuel burned in chamber containing compressed air.

For each type of system, there are many variations incorporated in the power plant in order to improve the efficiency of the process. Hybrid systems are also in use; an example is a combined-cycle generator in which the exhaust heat from a gas turbine is used to help provide heat for a steam-driven turbine. Typically, more than one of these generating facilities are built at the same site to take advantage of common infrastructure facilities such as fuel delivery systems, water sources, and convenient points to connect to the delivery system.

A small but not insignificant segment of the electric generation in the country includes technologies that are considered more environmentally benign than traditional sources, such as geothermal, wind, solar, and biomass. In many of these technologies, DC power is produced and use is made of inverters to change the DC to the alternating current needed for transmission and use.

Table 2-1 shows that in 2007 there were 994,888 mWs of capacity installed in the United States. Natural gas (39.5%), coal (31.4%), and nuclear (10.1%) comprised the largest sources of the energy for the production of electricity. A different picture is presented in Table 2-2. This table shows that the actual production of electricity relied most heavily on coal (48.5%), with natural gas (21.6%) and nuclear (19.4%) producing similar amounts.

Since the first edition of this book (2003), the vast majority of new capacity has used natural gas as its fuel. Continuing this trend, natural-gas-fired generators are planned as the largest source of new capacity, as shown in Table 2-3. There are significant changes from the forecast in the earlier text. In that text, there was no new coal or nuclear generation planned. The other major

Table 2-1. Installed summer capacity by energy source, Summer 2007

Energy source	Generator net summer capacity, MWs
Coal	312,738
Petroleum	56,068
Natural gas	392,876
Other gases	2,313
Nuclear	100, 266
Hydroelectric conventional	77,885
Other renewables*	30,069
Pumped storage	21,886
Other	788
Total	994,888

*Source: January 21, 2009 EIA Report "Electric Power Annual 2007."

change is the inclusion of a significant amounts of wind power in the present forecast.

Generators are selected, sized, and built to supply different parts of the daily customer load cycle. One type of generator might be designed to operate continuously at a fixed level for the entire day. This is a base-loaded generator. Another generator might be designed to run for a short period at times of peak customer demand. This is a peaking generator. Others might be designed for intermittent service.

Table 2-2. Fuel sources used to produce electricity, 2007

Energy source	
Coal	48.5%
Petroleum	1.6%
Natural gas	21.6%
Other gases	0.4%
Nuclear	19.4%
Hydroelectric	6.0%
Other renewables*	2.5%
Other	0.3%
Total	100%

*Source: January 21, 2009 EIA Report "Electric Power Annual 2007."

Table 2-3. Planned nameplate capacity additions from new generators, by energy source, 2008 through 2012

Energy source	Nameplate capacity (mWs)
Coal	23,347
Petroleum	1,910
Natural gas	48,100
Other gases	0
Nuclear	1,270
Hydroelectric conventional	236
Wind	14,617
Solar thermal and photovoltaic	2,395
Other renewables	1,098
Pumped storage	0
Other	22
Total	92,996

*Source: January 21, 2009 EIA Report "Electric Power Annual 2007."

One important aspect of the selection of a particular generator is the trade-off between its installed cost and its operating costs. Base-loaded generators have much higher installed costs per unit of capacity than peaking generators but much better efficiency and lower operating costs. Included in this decision is the availability and projected cost of fuel.

Prior utility practice has been to have enough generation available to meet the forecast customer seasonal peak demand plus an adequate reserve margin. Reserve margins were determined by conducting probability studies considering, among other things, the reliability of the existing generation and potential future loads. Systems that were mainly hydro-generation-based had lower reserve margins (~12%) than systems that had nuclear-, coal-, or oil-fired generation (~16–24%). The availability of aid from neighboring systems during shortages also had a large impact on the required reserve.

2.3 THE DELIVERY SYSTEM

A system of overhead wires, underground cables and submarine cables is used to deliver the electric energy from the generation sources to the customers. This delivery system, which electrically operates as a three-phase, alternating current system, has two major parts: transmission and distribution. Transmission is the facilities that deliver electricity from generators to substations which supply distribution facilities. Distribution facilities deliver the electricity to customers.

- Transmission
- Subtransmission
- Primary distribution
- Secondary distribution

The wires that make up the three phases are collectively called a line, circuit, or, when referring to the distribution system, a feeder.

The characteristic that differentiates the four parts of the delivery system from one another is the voltage at which they operate. In any one region of the country, transmission operates at the highest voltages, subtransmission at a lower voltage, then the primary distribution followed by the secondary distribution.

There is no uniformly agreed upon definition of what voltages constitute the transmission system. Some organizations consider voltage levels of 230 kV and above, whereas others consider voltage levels of 115 kV and above.[28] Table 2-4 shows the voltages that generally are considered for each grouping in the United States.

The transmission systems in the various parts of the United States have different characteristics because of differences in the locations of generating units and stations in relation to the load centers, differences in the sizes and types of generating units, differences in geography and environmental conditions, and differences in the time that the transmission systems were built. Due to these differences, we find different transmission voltages in various sections of the country; in some areas there is 765 kV, in others 500 kV and in others 345 kV.

As the industry developed, generation sites were usually located away from high-density customer load centers and the high-voltage transmission system was the most economic and reliable way to move the electricity over long distances. When new, large central station generating plants were built, they either were connected to the nearest point on the existing transmission system or they were the trigger to institute the construction of transmission

[28]Another way of classifying transmission is to refer to it as the bulk electric system. NERC, in its Glossary of Terms Used in Reliability Standards, defines the bulk electric system as generally those lines operating at 100 kV or above.

Table 2-4. Common HVAC transmission voltages in the United States

System	Voltages included
Transmission*	765 kV, 500 kV, 345 kV, 230 kV, 169 kV, 138 kV, 115 kV
Subtransmission	169 kV, 138 kV, 115 kV, 69 kV, 34.5 kV, 27 kV
Primary distribution	33 kV, 27 kV, 13.8 kV, 4 kV
Secondary distribution	120/240 volts, 120/208 volts, 277/480 volts

*In addition to the listed voltages, there are a number of high-voltage, direct current (HVDC) installations that are classified as transmission.

lines at a new higher transmission voltage.[29] The connection points are called substations or switching stations. These new higher voltage lines were connected to the existing system by means of transformers. This process is sometimes referred to as an overlay and resulted in older generation being connected to transmission at one voltage level and newer, larger generation connected at a new, higher voltage level. Over time, in some areas of the country, the lower voltage transmission facilities were called subtransmission systems.

The increase of transmission voltage levels in the United States in the twentieth century was shown in Figure 1-1. In 1999, there were almost 154,500 miles of HVAC transmission lines operating at a voltage of 230 kV or higher in the United States. This total had grown to over 200, 000 miles in 2007.

Transformers enable the wires and cables of different voltages to operate as a single system. A transformer is used to connect two (or more) voltage levels.[30]

Transformers are installed at the generating plant to allow the generators, whose terminal voltage is typically between 13 kV to 24 kV, to be connected to transmission. These are called generator step-up transformers. As the delivery system brings the electricity closer to the customers, transformers connect the higher voltage system to lower voltage facilities. Connections can be made to the local subtransmission system or directly to the primary distribution system. These are step-down transformers. Figure 2-1 shows a conceptual sketch of a power system.

[29]Remember that the electric system involves a large capital investment for facilities with service lives measured in decades. Changes to the system are incremental to that which already exists.
[30]Transformers are explained in Chapter 3.

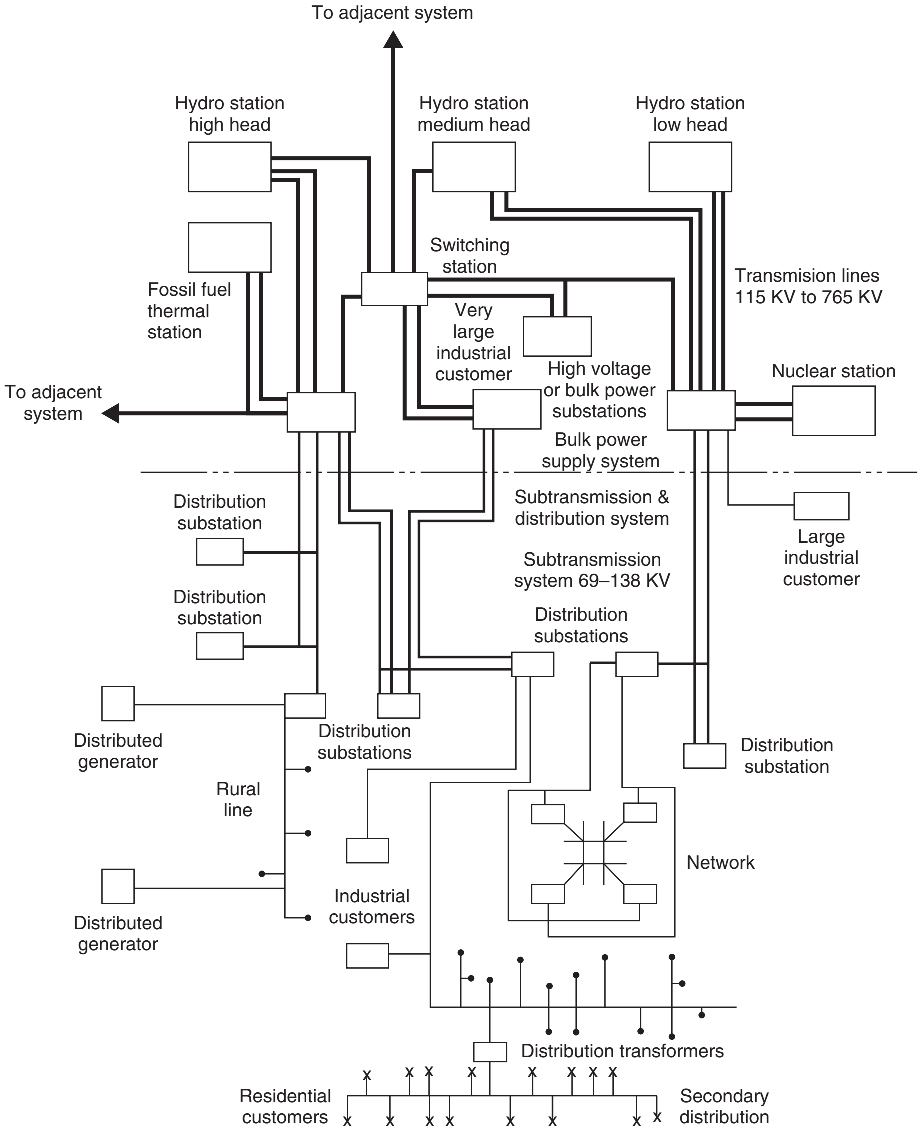

Figure 2-1. Conceptual diagram of a power system.

The connection point between the transmission system or the subtransmission system and the primary distribution system is called a distribution substation.[31] Depending on the size of the load supplied, there can be one or more transmission or subtransmission lines supplying the distribution substation. A distribution substation supplies a number of primary distribution feeders. These distribution feeders can supply larger customers directly or they connect to a secondary distribution system through a transformer affixed to the top of a local utility pole or in a small underground installation.

Depending on the magnitude of their peak demand, customers can be connected to any of the four systems. Typically, residential customers will be connected to the secondary distribution system. Commercial customers such as a supermarket or a commercial office building will normally be connected to the primary distribution system. Very large customers such as steel mills or aluminum plants can be connected to either the subtransmission or transmission system.

Interconnections

As individual companies built their own transmission systems, it became apparent that there were many reasons to built transmission lines connecting adjacent systems. These lines are usually called interconnections or interties. Among the reasons were:

- Sharing of generation reserves, thereby reducing the overall amount of generating capacity and capital investment needed
- Providing the ability to buy and sell electricity to take advantage of differences in production costs
- Facilitating operations by allowing more optimum maintenance scheduling
- Providing the ability to jointly construct and own power plants
- Providing local load support at or near the company boundaries

The Grid

The resulting transmission system is not a linear arrangement of lines fed from a single generating station and tied to a single pri-

[31]The substations are sometimes called switching stations. In addition, substations are also called high-voltage substations, bulk-power substations, and distribution substations.

mary distribution system but something much more complex. Generating units are located at a number of sites, as are the distribution substations. The generating sites are often electrically directly connected by transmission lines (some short and some long) to nearby substations where transmission lines also connect. Other transmission lines connect the substations together and also connect to distribution substations where there are connections to lower voltage facilities. From some of the substations, there are interconnections to other companies.

Taken together, this arrangement of transmission lines tied together at various substations provides a degree of redundancy in the delivery paths for the electric energy.

Power engineers have coined the terms "the grid," the "bulk power system," and "the interconnection" to describe the delivery system. There are five large grids in the United States, Canada, and Mexico: the Eastern Interconnection, the Western Interconnection, the Hydro Quebec system, and ERCOT (the Texas system and the Mexican system). The generators within each grid operate in synchronism with one another. The Canadian Province of Quebec is interconnected to the Eastern United States grid by nonsynchronous HVDC ties.

CHAPTER 3

BASIC ELECTRIC POWER CONCEPTS

This chapter describes as simply as possible the applicable physical laws and concepts needed to understand the physical operation of an electric power system. In Chapter 18, the commercial operation of a system is covered. An attempt has been made to present the material in a nontechnical (i.e., with as few equations as possible) manner.

It is important to remember that the operation of an electric power system is governed and described by the laws of physics, which are unchanging, whereas the commercial operations are subject to manmade rules that are subject to modification and change. There is an interrelationship between the two in that the rules established for commercial operations must recognize and respect the physical laws by which the power system operates and the commercial rules often determine the design and operation of the system.

A note on terminology is warranted. As the electric utility industry developed, an associated jargon evolved, some of which you have already been exposed to in Chapter 2. In some instances, the words used are simply contractions of longer terms; for example, the use of "amps" in place of "amperes" to describe electrical current. In other instances, a variety of terms are used to describe a single concept; for example, the use of the terms "grid," "the interconnection," and "the bulk power system" to describe the totality of all the electric transmission.[32]

[32]There are many glossaries defining the terms used in connection with electric power systems and businesses. One of the most useful is CIGRE Glossary of Terms Used in the Electricity Supply Industry, February 2002. This includes the definitions used by the IEEE, NERC, and EEI.

3.1 ELECTRIC ENERGY

Energy is defined as "the capacity for doing work." Electricity is but one of many forms of energy. Other familiar forms of, or descriptions of, energy are thermal or heat, light, mechanical, nuclear, and so on. Energy is also described as kinetic—that energy associated with a moving body—and potential energy—that energy associated with an object's position.

For centuries mankind has used energy in its various forms to enhance its standard of living. In many cases, ways have been devised to change energy from one form to another to increase its usefulness. An example, as old as mankind, is the burning of a fuel to produce heat and light.

Electrical energy possesses unique characteristics that make it an extremely valuable form of energy. It has unique properties:

- It can be produced at one location and transmitted to another instantaneously.
- It can be transformed to other energy forms and thereby be used in a variety of ways.
- It can be delivered by a system of wires and controlled.
- It cannot be stored.

Consistent terminology has always been an issue when discussing electricity and electric power. The convention is to use a system of measurement based on the MKS (meter, kilogram, second) system.

Table 3-1 summarizes the terms used to describe various aspects of electricity and shows some of the interrelationships between them. There is an electric charge associated with electrons. This charge is described by a quantity called a coulomb. The rate of flow of these charges is called the electric current and is described by a quantity called an ampere. One ampere is equal to the flow of one coulomb of charge during one second across a reference point. The capital letter, *I*, is used to indicate current and the quantity is sometimes referred to as amps. In many texts, electric current is described as a physical flow of electrons. It is not. The electrons do not flow.[33] Rather, electricity is a flow of energy as a result of electron vibrations. The mechanism is the transfer of energy from one electron to another as they collide with each other.

[33]"Amicus Brief to Supreme Court," August 2001, www.tca-us.com.

Table 3-1. Basic electric relationships

Quantity	Name or unit	Symbol	Relationships
Electric charge	coulomb	Q	
Time	seconds, hours	T	
Current	amperes	I	$I = q/t = V/R$
Resistance	ohms	R	$R = V/I$
Inductive reactance	ohms	X_L	$X_L = 2 \cdot \pi \cdot f \cdot L$
Capacitive reactance	ohms	X_C	$X_C = 1/(2 \cdot \pi \cdot f \cdot C)$
Impedance	ohms	Z	$Z = R + j(X_L + X_C)$
Voltage	Electromagnetic force (EMF), volts, kilovolts	E, V, kV	$V = I \cdot R$ $V = J/Q$
Power or real power	watts, kilowatts, megawatts,	P	$P = V \cdot I$ $P = I^2 \cdot R$ $P = V^2/R$
Reactive power	VArs, kiloVArs, megaVArs	Q	$Q = I^2 \cdot X_L$ $Q = I^2 \cdot X_C$
Apparent power		S	$S = P + jQ$
Energy	kilowatthours, megawatthours, joules	J	$J = V \cdot I \cdot t$ $J = I^2 \cdot R \cdot t$
Frequency	hertz, cycles per second	F	

Electric power systems thus provide a service, the availability of energy, not a product, to consumers.

Electromagnetic force (EMF), voltage, and difference in potential are different descriptions of the notion of what causes these charges to flow. A physics text would define voltage as the energy per unit of charge where energy is measured by a quantity called a watt-second.[34] An engineering text would say that a difference in potential (or of voltage) of one volt causes a current of one ampere to flow through a circuit that has a resistance of one ohm.

The letter *E* is used when referring to a voltage source such as a generator or a battery and is often called an electromagnetic force. The letter *V* is used in all other instances. In both cases, the quantity is measured by a quantity called a volt.[35] One volt is equal to one watt-second of energy per one coulomb of charge.

Voltage can be thought of as electric potential to deliver energy.[36] Differences in voltage measure the work that would have to

[34]In physics texts, the term joule is also used for energy. One joule = 1 watt-second.
[35]Named after Alessandro Volta, (1745–1827), an Italian who invented the battery.
[36]The voltage associated with an electric generator is called an electromagnetic force or EMF.

be done[37] to move a unit charge from a point of one voltage to that of another voltage.

When a source of voltage is applied to a wire connected to a device that uses the electric energy, a current will flow. A current will not flow if the wire is open. The material in the wire offers some resistance to the flow of current. This resistance is described by a quantity called an ohm.[38] One ohm is defined as the resistance of a circuit element when an applied voltage of one volt results in a current of one ampere. The resistance of wire depends on the material it is made of, the cross sectional area of the wire, and its length. For a given material, the larger the cross sectional area, the lower the resistance. The letter R is used to represent resistance in ohms.

The relationship between voltage, current, and resistance is known as Ohm's Law: voltage = current multiplied by resistance. This relationship is applicable for direct current conditions. Later in this chapter, we will introduce a version of this law when it is applied to alternating current circuits of the type used in power systems.

As mentioned earlier, electricity is a form of energy that is measured by a quantity called a watt-second. Electric utility customers usually see their bills keyed to their watt-hour usage. A related but different quantity is electric power. The unit of power is the watt. Power can be thought of as the instantaneous magnitude of the energy demand. It is discussed further in Chapter 4.

In an electric power system, the magnitudes of many quantities are such that larger units are needed to describe them. The larger increments usually encountered are described by the addition of the term kilo or the term mega to the base unit. For example, a kilovolt is 1000 volts, a kilowatt is 1000 watts, a megawatt is 1,000,000 watts or 1000 kilowatts, and a kilowatt-hour is 1000 watt hours.

3.2 CONCEPTS RELATING TO THE FLOW OF ELECTRICITY

The two laws that define the flow pattern of electricity through electric lines are known as Kirchhoff's Laws.[39] These laws reflect two basic physical concepts:

[37]This work would be done against the electric field.
[38]Named after George Simon Ohm (1787–1854), a German physicist.
[39]Named after Gustav Robert Kirchhoff (1824–1887), a German physicist.

1. The algebraic sum of the voltage drops around a closed loop is zero. The voltage across a source is considered positive, whereas the voltage drop across an element (i.e., a resistor) is considered negative.
2. The algebraic sum of currents entering any common point (a node) where three or more lines connect must equal the algebraic sum of the currents leaving that point.

In a complex network of lines such as one finds in a power system, the flow of power and current in any one line is determined by the line's electrical characteristics, the characteristics of the other lines in the network, the location of the power injections, and the locations of the power deliveries. All lines operating in a network participate to a greater or lesser extent whenever there is an increment in generation to supply an increment of load. Later in this chapter, we will discuss this notion in more detail.

Direct Current (DC)

The first utility systems installed by Edison used direct current technology. The electricity in a direct current system is the same as found when a battery is used. If one looked at a picture of the voltage and the current, one would see that both had a constant, nonvarying value. Not long after Edison installed his direct current system, others[40] realized that the use of an alternating current system had advantages over the direct current. The concepts discussed heretofore apply to direct current systems.

Alternating Current (AC)

The modern electric power system is an alternating current, three-phase system. Electricity is generated by synchronous generators, which are machines that convert the rotational energy of a shaft into electrical energy. The generator shaft or rotor is rotated by means of a turbine, as discussed in Chapter 5.

The energy conversion is based on a phenomenon associated with magnetism and electricity called induction. If a stationary wire loop is placed in the field of a rotating magnet, an electric current will be induced in the wire. The rotor of an electric generator is made to work like a magnet by energizing conductors

[40]George Westinghouse and Nicola Tesla.

imbedded in it with a source of direct current. The system that provides direct current to the rotor windings is called the excitation system. The energized windings on the rotor are conventionally called the field or field circuit. In modern generators, the direct current excitation is derived from an alternating current source that has been rectified to provide direct current.

The direct current excitation establishes a magnetic field in the metal of the rotor that extends across the air gap between the rotor and the stationary part of the generator (stator or armature). Electricity is induced in coils that are placed in slots in the stator. The voltage induced in any one coil reflects the time-varying characteristic of the magnetic field, as viewed by a stationary observer, caused by the rotation of the rotor. The magnitude of the induced voltage can be adjusted up or down by changing the magnitude of the direct current flowing in the rotor. This is done by an automatic voltage regulator in the excitation system, which monitors the voltage at the terminal of the electric generator and adjusts the field voltage up or down as required to maintain the desired generator terminal voltage.

The induced voltage and current have a sinusoidal shape; in each cycle of 360 degrees, they start at a zero value at zero degrees, rise to a positive maximum at 90 degrees, fall to zero at 180 degrees, continue to fall to a negative maximum at 270 degrees, and return to zero at 360 degrees, where the process repeats. Figure 3-1 shows one cycle. This sinusoidal shape reflects the rotating pattern of the magnetic field produced on the rotor. If the stator coil is connected to an external load, current will flow. The current will also be oscillatory in nature, hence the name alternating current. The number of full cycles that occur in a set time defines the frequency of the electricity. In the United States and many other areas of the world, the frequency is 60 hertz[41] or cycles per second. In other areas, a frequency of 50 cycles is used. The frequency is set by the number of magnetic circuits that are established on the rotor. The frequency of the electricity produced by a particular generator is defined as

$$f = (n \cdot p)/60$$

where n is the speed in revolutions per minute (rpm) and p is the number of pairs of magnetic poles.[42] Steam turbines rotate at high

[41]Named after Heinrich R. Hertz (1857–1894), a German physicist.
[42]In this text, centered dot (·) is used to indicate multiplication.

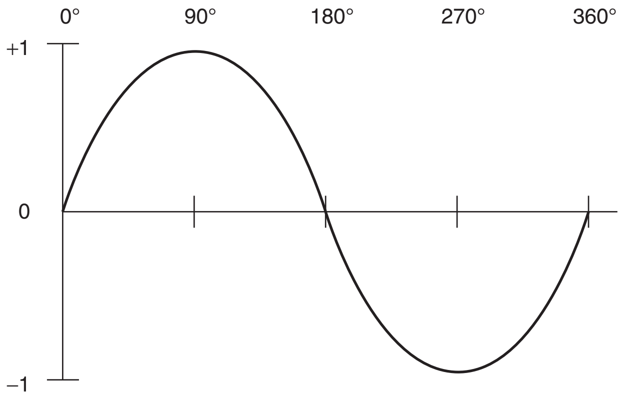

Figure 3-1. Sinusoidal shape of voltage or current.

speeds. For example, if a single magnetic circuit is established, it will contain two magnetic poles (a single pair consisting of a north and a south pole), and a speed of 3600 rpm will result in a frequency of 60 hertz. Alternately, if two magnetic circuits are established using two pairs of poles, a speed of only 1800 rpm is needed to produce a frequency of 60 hertz. Hydraulic turbines rotate at relatively low speeds and will have many poles to produce the required frequency.

Because of the oscillatory nature of the voltage and current, an "effective" voltage[43] and current value is defined. These effective values are considered to be equivalent to the direct current voltage and currents that would produce the same power dissipation (as heat) in a resistance. The effective value for a sine wave is equal to 0.707 times the peak value. In the United States, for example, the household voltage of 120 volts is an effective value and corresponds to a peak value of 169.7 volts.

Three Phases

The efficiency of the energy transformation and delivery process improves as the number of independent coils located on the stator is increased. The electrical conductors on the stator are physically arranged so that three separate but equal voltages are produced. The three conductors are connected together at a common point, resulting in a configuration called a wye or a delta. The rotating

[43]The term root mean squared (RMS) is also used.

patterns of these voltages are displaced from one another by 120 degrees. Taken together, the voltages and currents in the three coils become the three phases of a single circuit.

In a wye connection, two voltage measurements are defined: the phase voltage of the phase with respect to the neutral point, V_{LN}; and the voltage between phases or between lines, V_{LL}. Often, the neutral point is grounded. When the system is balanced, generators and customer load are connected in such a way as to result in voltages and currents on each phase of a circuit equal in magnitude but displaced by 120 degrees. These two voltages are related as follows:

$$V_{LL} = \sqrt{3} \cdot V_{LN} = 1.732 \cdot V_{LN}$$

In a delta connection, the three wires are in connected a way similar to an equilateral triangle. When balanced, the voltages across each phase (the line-to-line voltages) are equal but displaced in time by 120 degrees.

The use of delta or wye connections is especially important in the distribution system, where many variations are used. For example, the primary distribution may be wye connected and the secondary may be delta connected. There is no single standard nationwide.

The convention used when referring to power system voltages is to use the effective or RMS value of the line-to-line voltage.

Synchronism

When a number of generators are connected to the same electric grid, they are said to be in synchronism because they operate at the same frequency and the angular differences between the voltage angles of each generator are stable and less than 90 degrees. Units operating in synchronism are magnetically coupled by their connections through the power system. If any one changes its angle of operation, all the others are affected.

3.3 CHARACTERISTICS OF AC SYSTEMS

Resistance

In an AC system, the voltage across a resistor and the current flowing through it are said to be in phase when their zero values and their maximum values occur at the same times.

There are two types of fields associated with an AC electric system: electric fields and magnetic fields. Electric fields relate to the voltage and magnetic fields relate to the current.[44] The waveforms of the voltage and current associated with both of these characteristics are not in phase, that is, the times of the maximum and zero values are not identical.

Induction and Inductive Reactance

When we discussed the operation of a generator, we noted that an electric voltage is induced in a wire when a moving magnetic field "cuts" that wire. Similarly, a current varying with time (an alternating current) will produce a magnetic field around the wire carrying the current. Since the current is varying, so will be the magnetic field. This varying magnetic field "cuts" the conductor and a voltage is induced in the wire that acts to impede the originating current.

The relationship between the current and the induced voltage is defined by a quantity called the inductance. One henry is the amount of inductance required to induce one volt when the current is changing at the rate of one ampere per second. The letter L is used to represent the inductance in henrys.

The inductance, L, of one phase of a transmission or distribution line is calculated by considering the self-inductance of the individual phase conductor and the mutual inductance between that phase and all other nearby phases, both of the same circuit/feeder and other nearby circuits/feeders. These quantities are calculated based on the physical dimensions of the wires and the distances between them.

The induced voltage across an inductor will be maximum when the rate of change of current is greatest. Because of the sinusoidal shape of the current, this occurs when the actual current is zero. Thus, the induced voltage reaches its maximum value a quarter-cycle before the current does; the voltage across an inductor is said to lead the current by 90 degrees or, conversely, the current lags the voltage by 90 degrees.

[44]Since they operate at high voltage, transmission lines generate strong electric fields. If they are heavily loaded, that is, carrying large amounts of power, they also will have strong magnetic fields. Distribution lines, which operate at lower voltages, generate weak electric fields, but can generate strong magnetic fields depending on the local customer load levels.

The inductive reactance, X_L is a term defined to enable us to calculate the magnitude of the voltage drop across an inductor. The inductive reactance is measured in ohms and it is equal to $2 \cdot \pi \cdot f \cdot L$, where $2\pi f$ is the rotational speed in radians per second; π is called pi and its value is 3.1416, f = frequency in hertz, and L = inductance in henrys. Inductances consume reactive power or VARs equal to I^2X_L.

Capacitance and Capacitive Reactance

An electric field around a charged conductor results from a potential difference between the conductor and ground. There is also a potential difference between each conductor in a three-phase circuit and with any other nearby transmission lines. The relationship between the charge and the potential difference is defined by a quantity called the capacitance. One farad is the amount of capacitance present when a charge of one coulomb produces a potential difference of one volt. The letter F is used to represent the capacitance in farads.

The capacitance, C, depends on the dimensions of the conductor and the spacing between it and the adjacent lines and ground. The flow of charge (or current) will be greatest when the rate of change of voltage is at a maximum. This occurs when the voltage wave crosses the zero point. Thus, in an alternating current system, the current across a capacitor reaches its maximum value a quarter-cycle before the voltage does; the voltage is said to lag the current by 90 degrees, or conversely, the current leads the voltage by 90 degrees.

The capacitive reactance, X_C, is a term defined equal to $½ \cdot \pi \cdot f \cdot C$, where C = capacitance in farads. The unit of the capacitive reactance is ohms. In a power system, the capacitive reactance is viewed as a shunt connecting the conductor to ground. Capacitors supply reactive power or VARs equal to I^2X_C. Figure 3-2 demonstrates the current and voltage relationships for a resistor, an inductor, and a capacitor.

Both inductive reactance and capacitive reactance have an impact on the relationship between voltage and current in electric circuits. Although they are both measured in ohms, they cannot be added to the resistance of the circuit since their impacts are quite different from that of resistance. In fact, their impacts differ one from each other. The current through an inductor leads the voltage

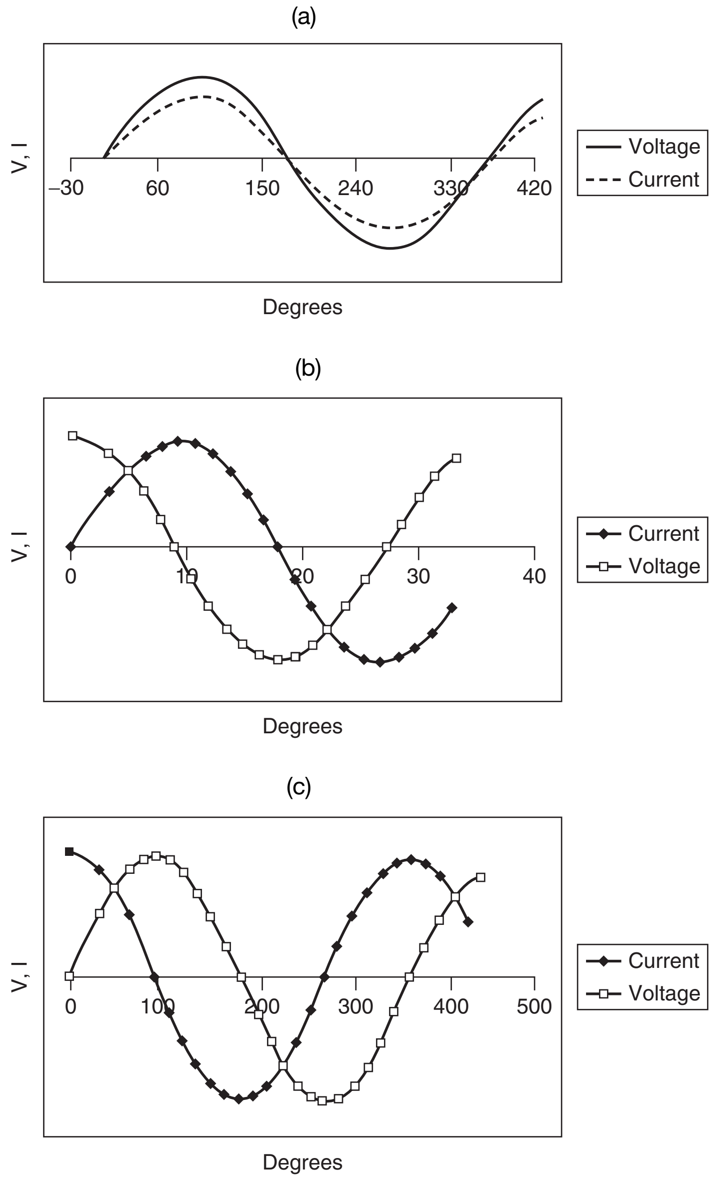

Figure 3-2. Current and voltage relationships in a resistor (a), inductor (b), and a capacitor (c).

by 90 degrees, whereas current through a capacitor lags the voltage by 90 degrees. Because of this difference, their effects will cancel one another. The convention is to consider the effect associated with the inductive reactance as a positive value and that with the capacitive reactance a negative value. A general term, reactance, is defined as the net effect of the capacitive reactance and inductive reactance. It is denoted by the capital letter *X*.

Impedance

Once determined, the reactance is combined with the resistance of a circuit to form a new quantity called impedance, which is denoted by the capital letter *Z*. To determine a single-number representation of the impedance, the concept known as complex numbers is employed. Simply speaking, resistance and reactance are treated as both legs of a right triangle separated by 90 degrees. A common way of representing the impedance term is

$$Z = R + j\,(X_L - X_C)$$

where the letter *j* is used as a convention to indicate that the reactance is not to be directly added to the resistance. The magnitude of the impedance is determined by Pythagoras' Theorem—the square of the impedance is equal to the sum of the squares of the resistance and the reactance:

$$Z^2 = R^2 + X^2$$

or

$$Z = (R^2 + X^2)^{0.5}$$

where

$$X = X_L - X_C$$

3.4 OHM'S LAW FOR ALTERNATING CURRENT

Ohm's Law, as discussed for DC circuits, cannot be applied to AC circuits since it recognizes only resistance and not the inductive and capacitive reactance effects. The law can be modified to take into consideration the effect of reactance by simply replacing the term for the resistance with a term for the circuit's impedance and treating the voltage and the current as time-varying quantities rather than as constants as in a direct current circuit. In engineering textbooks, the AC quantities are indicated by letters with lines drawn over them or by bold letters. We shall follow this latter convention:

$$\mathbf{V} = \mathbf{I} \cdot \mathbf{Z}$$

3.5 POWER IN ALTERNATING CURRENT CIRCUITS

In a DC circuit, the power is equal to the voltage times the current, or $P = V \cdot I$. This is also true in an AC circuit when the current and voltage are in phase, that is, when the circuit is resistive. But, if the AC circuit contains reactance, there is a power component associated with the magnetic and/or electric fields. The power associated with these fields is not consumed as it is in a resistance but, rather, stored and then discharged as the alternating electric current/voltage goes through its cycle. This leads to another definition:

Apparent power = real or true power (associated with a resistance) + reactive power[45] (associated with an inductance or capacitance)

Using symbols:

$$\mathbf{S} = \mathbf{P} + j\mathbf{Q}$$

A related concept is that of power factor, which is defined as a magnitude of P divided by a magnitude of S. If the power factor is too low (typically under 0.85) because of the magnitude of the reactive component Q, voltages will be low, requiring corrective actions to be taken.

[45]Another name that has been used for this quality is imaginary power. The name is derived from the application of the complex number convention to calculate Z.

Real Power

Real power is available to do work and is equal to the value of the resistance multiplied by the square of the current through the resistance. It is measured by quantities called megawatts (mW) or kilowatts (kW).

$$P = I^2 \cdot R$$

Reactive Power

Reactance neither consumes nor supplies power and energy. Instead, power and energy are stored in the electric and magnetic fields associated with inductance and capacitance.

The inductive reactive power, Q_L, relates to the magnetic field formed as current flows through a line. This value is calculated by multiplying the square of the current through the line by the inductive reactance. The reactive power is measured by a quantity called volt-ampere reactive or VAR and is calculated as follows:

$$Q_L = I^2 \cdot X_L$$

As the length of a line increases, its inductive reactance (X_L) increases, and there is an increase in Q_L. However, as Q_L increases, the voltage drop across the line also increases and the voltage at the far or receiving end of the line drops. To reduce the voltage drop and support the voltage at the receiving end, more capacitive reactive power is needed to offset the inductive effect.

The capacitive reactive power, Q_C, relates to the establishment of the electric field around a line. There are a number of ways to calculate this value, but the following offers insight into its effects on the transmission system:

$$Q_C = 3 \cdot V_{LN}^2 / X_C \qquad \text{or} \qquad = \sqrt{3} \cdot V_{LL} \cdot I_C$$

Capacitive reactive power can come from the line itself or from other sources such as generators or from a capacitor bank.

Unfortunately, the capacitive reactive power associated with a line is not a constant value. In a power system, under normal operations, the voltage level on any one line is kept more or less constant, so the reactive power associated with the capacitance of the line is also relatively constant. There can be problems at peak load times, if there is not enough of it, and likewise during low load times, if there is too much of it. Too little is associated with low voltages. Too much is associated with high voltages.

A way of looking at this effect is by considering a quantity called a charging current, I_C. It is defined as the line-to-neutral voltage divided by the capacitive reactance:

$$I_C = V_{LN}/X_C$$

If the charging current becomes too large because of the line length and there is insufficient inductive reactive power to offset the capacitive effect (i.e., a condition experienced at light loads and low load currents), much of the line's current carrying capacity may be eaten up by charging current. This situation sets limits on the length of an overhead line or of a cable that can be operated without installing some intermediate measures to offset the capacitive current, especially during light load periods. It is useful to visualize the impact of various devices on the reactive power of a power system as follows:

- Sources of reactive power that raise voltage:
  - Generators
  - Capacitors
  - Lightly loaded transmission lines due to the capacitive charging effect
- Sinks of reactive power that lower voltage:
  - Inductors
  - Transformers
  - Most heavily loaded transmission lines due to the $I^2 \cdot X_L$ effect.
  - Most customer load (due to the presence of induction motors and the supply to other electric fields)
  - Generators

A synchronous generator can be made to be either a source or a sink of reactive power by using the generator excitation system to vary the level of its DC field voltage. During peak load conditions, generators are usually operated to supply reactive power to the grid to help maintain adequate voltage levels. During light load conditions, generators may be used to absorb excess reactive power from the grid to prevent voltages from becoming too high, especially where there are long transmission lines or cables nearby.[46]

[46]See the generator capacity curve in Chapter 5.

Transformers

The device that allows the use of a multivoltage level energy delivery system is a transformer. A transformer makes use of the principle of electromagnetic induction that we have discussed previously. Figure 3-3 contains a simplified example showing two independent circuits wound about a common core. A magnetic path, B, is established in the core by the AC in one of the circuits.

It can be shown that because of the time-varying nature of the magnetic field created by the current in coil 1, an AC voltage is induced in the second coil (coil 2). The induced voltage is related to the AC voltage impressed on the first coil (coil 1) multiplied by the ratio of the number of turns (N_2/N_1) that the respective circuits make around the core. Symbolically,

$$V_2 = V_1 \cdot (N_2/N_1)$$

Depending on the number of turns of wire constructed into the transformer, the voltage level on the secondary side can be increased or can be decreased from that on the primary side. This capability offers significant flexibility in the design of a power system.

In an ideal situation (no losses associated with the transformer), the power entering the transformer is equal to the power exiting it:

$$V_1 \cdot I_1 = V_2 \cdot I_2$$

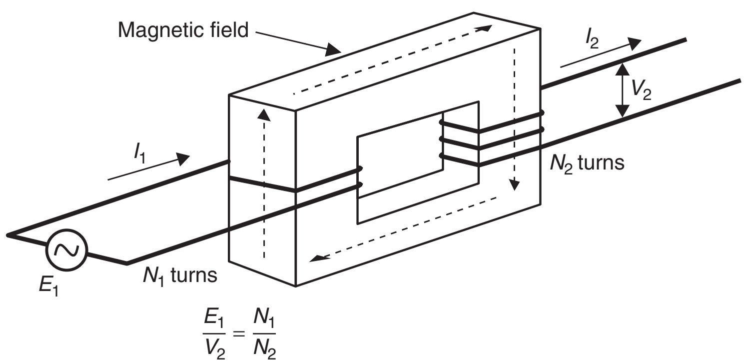

Figure 3-3. Idealized transformer windings.

A significant reduction of real power line losses can be achieved by using a transformer to raise the transmission voltage and thereby lowering current, resulting in lower I^2R losses.

3.6 POWER FLOW

By using Kirchhoff's Laws and the concepts of impedance, calculations can be made to determine the currents, real and reactive powers flowing in transmission lines, and the voltages at all terminals (buses and nodes) in an AC system. Textbooks are written to educate students in the techniques of performing the required calculations. For our purposes, we will summarize the insights that one gets from doing those analyses.[47]

The magnitude and direction of power flow on a transmission line is dependent predominately on the phase angle difference (θ_{12}) between the voltages at its terminals, since the line reactance is constant and the terminal voltages V_1 and V_2 are essentially constant:

$$P_{12} = (V_1 \cdot V_2/X_{12}) \cdot \text{sine } \theta_{12}$$

Division of Power Flow

Power flows on all possible transmission paths between a source of generation and a load approximately in proportion to the relative impedances of all the paths, not only of the most direct path.[48] It will not flow just on a path for which a commercial arrangement has been made (contract path), nor only on the facilities of the owner or purchaser of the electricity.

For a vertically integrated utility, electricity from its generating plants will use all parallel paths to reach its load, including transmission facilities of neighboring utilities. When interregional power transfers are scheduled, the facilities of many utilities, not only those involved in the transaction, may carry some of the

[47]In many instances, the resistance of elements can be ignored because they are typically an order of magnitude smaller than the reactance of the same element.
[48]Development is underway on devices that can be inserted in series with transmission lines to change their effective series impedance. Some of these devices are undergoing field testing. If successful, these devices will provide some level of control of the paths on which power will flow.

power. This phenomenon will always occur, no matter who owns the power plants.

Voltage Drop and Reactive Power Flow

The magnitude of the voltage drop across a transmission line will depend predominately on the amount of reactive power (*Q*) that flows through the reactance of the line.[49] This means that to minimize a voltage drop, reactive power sources should be located as close as possible to the load. This relationship is summarized in the following formula:

$$(V_1 - V_2) = X_L \cdot Q/V_2$$

3.7 STABILITY

Stability refers to the ability of the generators in a power system to operate in synchronism both under normal conditions and following disturbances. Four categories of instability are:

1. Steady-state instability
2. Voltage instability
3. Transient instability
4. Dynamic instability

Steady-state instability refers to the condition in which the equilibrium of the generators connected to the power system cannot accommodate increases in power requirements that occur relatively slowly or when a transmission line is removed from service for maintenance.

Since the power flow from one point to another is proportional to the sine of the angular difference between the voltages at the two points and inversely proportional to the total impedance of the circuits connecting the two points, there is a maximum level of power flow, that is, the delivery level at which the angular difference is 90 degrees and the sine is equal to one.

The fact that the power flow is dependent on the sine of the angular difference between the voltages has an important significance in that it defines the maximum amount of power that can be moved

[49]"VARs don't travel well"—G. C. Loehr.

across the facilities connected by the impedance X_{12}. If the power required by the customers at bus 2 is greater than the amount that can be delivered at a 90 degrees separation in the voltages, the system is unworkable. A technical term to describe a situation in which the customer load at bus 2 slowly increases and the angular spread responds until it reaches the 90 degree point and then goes beyond 90 degrees is that the system becomes unstable and will collapse.

If the net impedance is increased by removing a line, less power can be transmitted. If there are a number of lines connecting bus 1 with bus 2, the loss or outage of any one of them will increase the impedance between the two buses and the system can again become unstable. Conversely, if the net impedance is reduced, more power can be transmitted. The value of the net impedance can be reduced by:

- Building an additional line(s) in parallel
- Raising the design voltage of one or more of the existing lines
- Decreasing the impedance of any of the existing lines by inserting a capacitor in series (remember X_C cancels out X_L).

Voltage instability refers to a condition in which there are inadequate resources to maintain voltages on the transmission system. This phenomenon can occur in response to slow changes in the reactive demands on the system such as increasing customer demand during the day or as transmission power flows increase reactive line losses. It has been a factor in a number of blackouts including France in 1978, Tokyo in 1987, and the Northeast United States in 2003.

Transient instability refers to the condition in which there is a disturbance on the system that causes a disruption in the synchronism or balance of the system. The disturbance can be a number of types of varying degrees of severity:

- The opening of a transmission line increasing the X_L of the system
- The occurrence of a fault decreasing voltage on the system. (The voltage at the fault location is depressed or goes to zero, decreasing all system voltages in the area.)
- The loss of a generator disturbing the energy balance and requiring an increase in the angular separation as other generators adjust to make up the lost energy
- The loss of a large block of load in an exporting area

When there is a disturbance on the system, the energy balance of generators is disturbed. Under normal conditions, the mechanical energy input to the generator equals the net electrical energy output plus losses in the conversion process within the turbine generator and the power consumed in the power plant.

If a generator sees the electric demand at its terminal in excess of its mechanical energy input, it will tend to slow down as rotational energy is removed from its rotor to supply the new increased demand. If a generator sees an electric demand at its terminal less than its mechanical energy input, it will tend to speed up due to the sudden energy imbalance. This initial reaction is called the inertial response. Generators are equipment with systems called speed governors, which measure the speed of the generator and which will cause the valves controlling the steam flowing into the turbine to increase or decrease flow to restore the generator speed to its desired point.

Automatic Generation Controls (AGC)

Disturbances may also change the voltage at the generator's terminals. In response, the generator's automatic voltage regulating system will sense the change and adjust the generator's field excitation, either up or down, to compensate.

Transient stability or instability considers that period immediately after a disturbance, usually before the generator's governor and other control systems have a chance to operate. In all cases, the disturbance causes the generator angles to change automatically as they adjust to find a new stable operating point with respect to one another. In an unstable case, the angular separation between one generator or group of generators and another group keeps increasing. This type of instability happens so quickly, in a few seconds, that operator corrective action is impossible.

If stable conditions exist, the generator's speed governor system, sensing the beginning of change in speed, will then react to either admit more mechanical energy into the rotor to regain its speed or to reduce the energy input to reduce the speed. Directives may also be received by the generator from the company or balancing area control center to adjust its scheduled output.

In addition to the measures noted to improve steady-state stability, other design measures available for selected disturbances to mitigate this type instability are:

- Increasing the speed by which relays detect the fault and the speed by which circuit breakers operate to disconnect the faulted equipment sooner
- Using dynamic braking resistors which, in the event of a fault, are automatically connected to the system near generators to reduce export from the generators
- Fast valving systems on turbines allowing rapid reduction in the mechanical energy input to the turbine generator
- Automatic generator tripping
- Automatic load disconnection using underfrequency or undervoltage protective systems
- Special transmission line tripping schemes

Dynamic instability refers to a condition in which the control systems of generators interact in such a way as to produce oscillations between generators or groups of generators that increase in magnitude and result in instability, that is, there is insufficient damping of the oscillations. These conditions can occur either in normal operation or after a disturbance.

Results of Instability

In cases of instability, as the generator angles separate, the voltage and current angular relationships at points on the system change drastically. Some of the protective line relays will detect these changes and react as if they were due to fault conditions causing the opening of many transmission lines.

The resulting transmission system is usually segmented into two or more electrically isolated islands, some of which will have excess generation and some will be generation deficient. In excess generation pockets, the frequency will rise. In generation deficient pockets, the frequency will fall. If the frequency falls too far, generator auxiliary systems (motors and fans) will fail, causing generators to be automatically disconnected by their protective devices. Industry practice is to provide for situations in which there is insufficient generation by installing underfrequency load-shedding relays. These relays, keyed to various levels of low frequency, will actuate the disconnection of blocks of customer load in an effort to restore the load–generation balance. Since the size and extent of any electrical islands formed are not predictable, the application of underfrequency load-shedding relays is often more art than science.

In situations where the frequency rises, generators will be automatically removed from service by protective devices detecting a potentially damaging overspeed condition. If studies indicate electrical islands with excess generation, selective generation disconnection controls can be installed.

CHAPTER 4

ELECTRIC ENERGY CONSUMPTION

This chapter discusses customer electric energy requirements. Industry practice is to refer to these requirements as "customer load." To supply customer load, the power system must also supply the losses in the system that delivers the energy. These losses are typically between 7% and 12% of the power delivered to consumers, larger than any single consumer. The power system planner must forecast and provide capacity to meet these needs.

4.1 END USES FOR ELECTRICITY

Electricity serves a wide variety of end uses. Each customer served by an electric utility has his own unique set of electric use requirements. Individual customer requirements for electric energy vary in magnitude and timing and reflect an almost endless array of devices employed individually or in combination with other devices. Among the principal categories of electric end-use equipment are:

- Electric motors
- Electric furnaces
- Lighting
- Space conditioning systems
- Electric communications, television, and computing devices
- Machine tools
- Electrolytic devices

Within each of these principal categories, a wide variety of specific applications can be found. For example, electric motors include such subcategories as compressors, pumps, fans, and conveyors. Furthermore, even within such subcategories specific types of equipment may differ substantially in size, efficiency, and time pattern of electricity requirements.

4.2 CUSTOMER CLASSES

Customers of electric utilities also differ widely in their requirements for electricity. Such differences are reflected in both the timing and magnitude of requirements. Although each electric utility customer tends to have a somewhat unique pattern of electricity use requirements, customers are frequently segregated into classes of use for technical, administrative, and regulatory purposes. The primary classes of electric customers separate users into residential, commercial, industrial, and agricultural sectors. Some specific utilities, however, may identify other primary classes of customers. For example, generating utilities may have wholesale power customers. Customers in this class generally include other generating and nongenerating utilities which generally resell the purchased power to their own retail customers.

Other retail classes of customers may include street lighting systems, electric rail systems, churches, and governmental users of electricity. Still other customers are considered preference customers. These are typically found on federal- or state-owned utilities (Bonneville Power Administration, Southwest Power Administration, Tennessee Valley Authority, and Power Authority of the State of New York). These utility systems were developed specifically to provide electric service to these customers, who, therefore, must receive all of their electrical requirements at the lowest costs before power can be sold to other customers inside or outside the service areas of these systems.

Within these broad classes of service, customers may be further segregated on the basis of other technical and administrative parameters. Common distinctions of this type include:

- Phase and/or voltage level of service
- Whether service is from underground or overhead facilities
- The magnitude and/or timing of requirements
- Type of specific end use or major end-use requirement

- Physical location of the end use activity
- Quality or reliability of service provided

4.3 RATE CLASSES

Such distinctions in the character of service provided are frequently the basis for the establishment of rate classes for regulatory and rate setting purposes. For example, within the residential sector separate rate classes are often established for customers with electric space heating or electric water heat requirements. Some electric utilities have special rate classes for all-electric homes. Commercial and industrial customers may constitute separate rate classes or may be grouped together in general service rate classes. Also, within the broad category of general service customers, separate rate schedules may be established on the basis of the magnitude of customer requirements, type of customer end use, and the quality of service provided.

Definitions of rate classes may vary substantially among utilities and between service jurisdictions within the same utility. A single utility that provides service in more than one regulatory jurisdiction (e.g., more than one state) is likely to have a different set of rate class definitions in each jurisdiction.

Some states require that major electric systems provide "daily kilowatt demand load curves for each electric consumer class for which there is a separate rate." This means that major electric consuming devices (such as air conditioners, water heaters, and space heating systems in residential dwellings) must be submetered for a sample of customers. For other load research activities, utilities will occasionally measure the consumption patterns of customers on a single transmission or distribution circuit from substation or transformer locations. These and other aggregate measures of consumption may also be used in the planning and operation of an individual utility's system, power pools, or reliability councils.

4.4 DEMAND AND ENERGY

The metering of electric utility service typically involves measurement of the amount of electricity used over a period of time and/or measurement of the rate (or rates) of use during the same period. Measures of the rate of use are measures of "demand" and they are usually stated in terms of watts or kilowatts (i.e., 1000 watts). A customer who turns on a 100-watt light bulb creates an instantaneous demand of 100 watts on the electric system. If that light bulb were to operate continuously for one hour, 100 watt-hours of electricity would be consumed. The watt-hours of consumption represent the "energy" measure of the customer requirements. If ten 100-watt light bulbs were operated continuously for one hour, the customer would consume one thousand watt-hours, or one kilowatt-hour, of electric energy.

Customer demand (i.e., the rate at which customers consume electricity) is not generally measured on an instantaneous basis. Instead, measures of customer's demands generally compute an average level of usage over a relatively short period of time. The most common periods for measuring customer demands are 15-minute, 30-minute, and one-hour intervals. However, in special circumstances, demand measures as short as one minute or as long as three hours have been employed.

Energy

For billing purposes, electricity consumption by smaller customers (e.g., residential and small general service customers) is typically measured only in terms of the kilowatt-hours consumed. Only rarely are the maximum demands of smaller users of electricity directly metered. As the magnitude of customer requirement increases, the importance of measuring the maximum rate of consumption by the customer also increases. Most utilities install meters that measure both kilowatt-hour consumption and maximum monthly demands for all customers that have a preestablished consumption level. For example, a utility may require demand metering for all customers whose monthly demands are expected to exceed 25 kilowatts and/or for all customers whose monthly consumption exceeds 6000 kilowatt-hours. For certain very large customers or classes of customers, demands may be measured on a continuous basis (as opposed to just monthly maximum) for every 15-minute, 30-minute, or hourly period throughout a month.

The use of time-of-use rates (i.e., the cost per kilowatt-hour varies at various times of the day) has also required the metering of energy consumption and/or maximum demand by time-of-use periods. These rates require metering of consumption for discontinuous periods within each billing month. For example, one utility defines its peak period for large general service customers to include all weekday hours between 12 noon and 8:00 p.m.

In the United States, retail sales to the three major customer classifications for the years 1995–2008 as shown in Table 4-1. While residential sales have grown 32% over the period, the commercial sector has grown 57% and industrial electric sales have remained constant. However, this does not capture any self-generation by the industrial sector.

Effects of Load Diversity

There are two types of load diversity: that of different peak loads between customer classes, and that of different peak loads at different hours of the day and days of the year. From continuously recorded demand data, a number of different demand measures may be derived. The most commonly metered measure of customer demand is individual customer maximum demand. This measure indicates the highest demand level incurred by the customer during any metering interval in a billing period. Due to varying types and uses of electrical equipment across customers, there are broad differences in the times at which customers achieve their individual maximum demands. For example, one customer whose major use of electricity is outdoor light may regu-

Table 4-1. Customer electric consumption by sector 2008, gWhrs

	Sales					
Period	Residential	Commercial	Industrial	Transportation	Other	Total
1995	1,042,501	862,684	1,012,693	NA	95,406	3,013,286
1996	1,082,511	887,445	1,033,631	NA	97,538	3,101,127
1997	1,075,880	928,632	1,038,196	NA	102,900	3,145,610
1998	1,130,109	979,400	1,051,203	NA	103,517	3,264,230
1999	1,144,923	1,001,995	1,058,216	NA	106,951	3,312,087
2000	1,192,446	1,055,232	1,064,239	NA	109,496	3,421,414
2001	1,201,606	1,083,068	996,609	NA	113,173	3,394,458
2002	1,265,179	1,104,496	990,237	NA	105,551	3,465,466
2003	1,275,823	1,198,727	1,012,373	6,809	NA	3,493,734
2004	1,291,981	1,230,424	1,017,849	7,223	NA	3,547,479
2005	1,359,227	1,275,079	1,019,156	7,506	NA	3,660,968
2006	1,351,520	1,299,743	1,011,297	7,357	NA	3,669,918
2007	1,392,241	1,336,315	1,027,832	8,173	NA	3,764,561
2008	1,379,307	1,352,453	982,150	7,652	NA	3,721,562

Source: EIA October 15, 2009 Report “Retail Sales to Ultimate Customers: Total by End-Use Sector.”

larly experience maximum demand in the late evening hours of the day, whereas a second customer, whose major requirement for electricity is for air conditioning, is more likely to experience a maximum demand during afternoon hours in the summer months. Furthermore, the electrical load requirements of an industrial process may be closely tied to work shift hours, or may be nearly flat throughout the 24-hour day if the process operates on a continuous basis.

These differences in the timing of individual maximum demands are referred to as diversity. Diversity in load requirements not only exists among individual customers, but also can be observed among rate classes, customer classes, jurisdictional divisions, utility systems, and power pools.

The inverse of diversity is coincidence. Coincident demand measures the maximum amount of load that occurs within a given measurement interval. If a customer has two or more electricity consuming devices at its facility or residence, the customer's individual maximum demand will occur at the time at which the requirements of the individual devices are most highly coincident (i.e., demonstrate the least diversity). The sum of the maximum requirements of the individual devices will always be greater than, or equal to, the customer's individual maximum demand.

Other measures of individual customer demands tend to relate the individual customer's requirements to rate class, customer class, jurisdictional, or system requirements. Due to diversity among customers, each individual customer's contribution to class, jurisdictional, or system maximum requirements, cannot be greater than, and tends to be less than, the customer's individual maximum demand.

System, jurisdictional, class, or customer demand are typically measured on an annual, monthly, or daily basis. However, billing data, for both demand and energy, typically do not correspond directly to calendar month or calendar year measures. Usage reported on a bill in January, for example, may include substantial amounts of consumption that occurred in December of the previous year. This occurs because cost-effective meter reading and bill processing schedules generally require that not all meters be read on the same day but rather some are read on each working day of each month. Each customer is billed based on his metered consumption in the prior billing cycle. Measures of actual requirements on a calendar month basis are not available for individual customers except where expensive continuously recording demand meters are installed.

At the system level, monthly aggregate requirements are usually determined by adding net electricity interchange into and out of an area to the net generation within the area from continuously recorded data typically maintained by utilities at the generation and transmission levels.

4.5 SYSTEM LOAD

The sum of each customer's coincident demand contributes to the "native" load of a utility system. This is the requirement for electric power placed on the utility's physical system by customers located within its franchised service area. It includes the actual customer requirements plus any electrical losses on the transmission and distribution system that are incurred when supplying these customer requirements. These losses are typically from 7% to 12% of customer energy consumption and as much as 50% of total system reactive requirements.

In addition to customer requirements and electrical losses, the electric utility's generating equipment must also provide electric power for the utility to operate its equipment. This includes the electricity needed to run various auxiliary devices within the generating stations (pumps, heaters, motors, etc.) and is known as "station service." This is typically about 5% of the energy produced in steam generating plants, and less for gas turbines and hydro plants.

Net peak system demand is the load used for planning purposes. This includes customer loads and system losses, but not the station service. Figure 4-1 shows a typical daily summer load pattern and Figure 4-2 shows an annual load duration curve. Both show that the peak load occurs for only a few hours on a hot summer day and for a small percentage of hours over the course of a year. In many areas, because of the weather sensitivity of customer demand, there are usually only a few percent of the hours in a year when the system load is at or greater than 95% of the peak load.

The net generation on a utility system includes net system load, plus or minus purchases or sales to other utilities. This load is sometimes called total load. When load data is obtained from utilities, it is essential that it be clearly delineated whether native

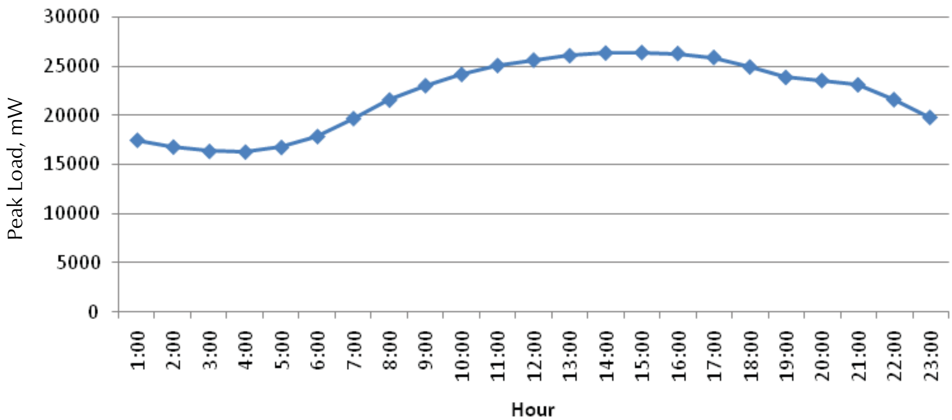

Figure 4-1. NYISO forecast peak load for August 4, 2009.

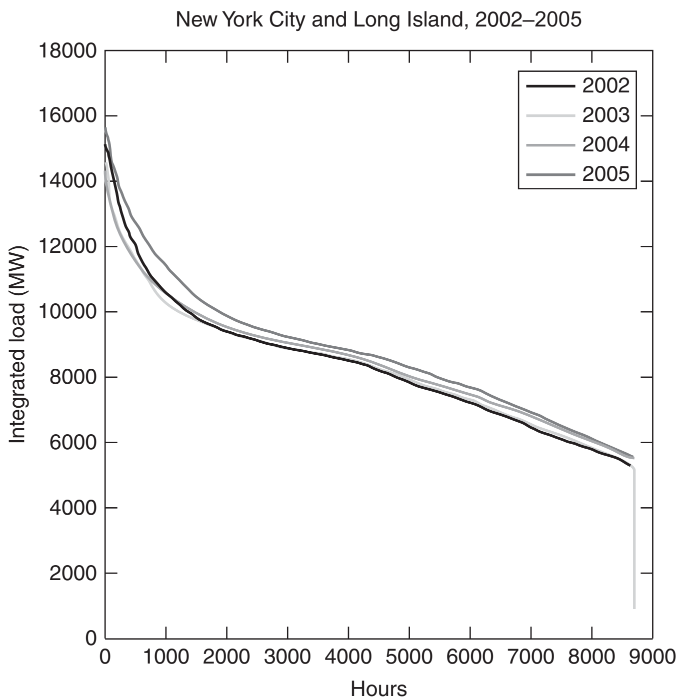

Figure 4-2. Yearly load duration curves for New York City and Long Island. Source: Presentation by Tim Mount, Cornell University, AAPA, Feb. 2007.

load or total load is desired. It is also important that net loads be obtained since this is the industry norm.

The load experienced in any one area varies daily, weekly, and seasonally. This variation is measured by a quantity called a load factor. A load factor is defined as the ratio of average load to peak load during a specific period of time, expressed as a percent. Residential loads tend to have poorer load factors than industrial loads. The lower the load factor, the lower the full utilization of installed generating and distribution capacity.

The diversity in customer peak loads can result in situations in which the time of the peak load in a specific geographic area may differ from the time of the system peak; that is, a residential area may peak in the evening whereas the system may peak during the late afternoon.

Load Management

Until the 1970s, emphasis was placed on ensuring that sufficient generating capacity was available to meet the peak load. That emphasis, however, was extremely expensive because of the rising cost of building generation plants, some of which only were needed for a few hours each year. Utilities instituted programs to manage demand so that the peak load could be reduced to obviate the need for the additional generating capacity.

Customer load can be reduced by charging more for power at certain times of the day or year, or it can be controlled directly by the electric utility (load management).[50] In load management, the electric company connects a control device to one or more appliances on the customer's premises. During periods of high demand, the electric company turns off the appliance for a period of time, thereby making it less necessary for the utility to keep generating reserves. In a sense, the utility has created additional interruptible customers. Tests indicate that, for many systems, the cost of load management equipment per kilowatt of demand reduction is far less than that of capacity added to meet each kilowatt of additional demand. However, the reduction in tariff required for customer acceptance may be quite large.

Although the exact definitions vary considerably, utility load management techniques are usually divided into two major classes: direct control, in which the utility controls end-use devices by

[50]Over the longer range, electric load can be reduced by replacing existing end-use devices with newer, more efficient ones.

means of supervisory control, and indirect control, for which load shifting is left to the discretion of the customer by provision of price incentives. It is not immediately clear how interruptible service contracts would be classified in such a partitioning. Some define two slightly different classes: active load management, which permits the utility to control, interrupt, or displace a fairly precise quantity of load for a fairly precise time interval, to accommodate a fairly specific need; and passive load management, which is subject to customer whim, and may or may not result in an optimum benefit to the utility. In this case, the former class clearly includes interruptible service as an active load management technique.

For the purposes of this discussion, the two classes will be designated utility-controlled load management and customer-controlled load management. Utility-controlled load management includes all load modification (or displacement) measures over which the utility retains complete control over whether to implement or not, as the need arises. Customer-controlled measures, on the other hand, not only include measures over which the customer maintains complete control, but also fixed-load control agreements (such as a preset, timed switch on a water heater) that, from the moment to moment, are not under the direct control of either party.

A classification of various utility-controlled and customer-controlled load management practices is presented in Table 4-2. As the table shows, utility-controlled measures are divided into those such as storage and pooling, which tend to increase the amount of capacity during peak systems, and those, such as interruptible service or remote load control, which attempt to reduce the load at these times. In either case, the net effect is to increase the difference between available generating capacity and system load during peak periods. All of the utility-controlled techniques

Table 4-2. A classification of utility load management techniques

Utility controlled		Customer controlled	
Supply side	Demand side	Backup or storage	End-use modification
Energy storage	Interruptible power	On-peak self-generation	Load deferral
Power pooling	Remote control of customer load	Customer energy storage for use during peak periods	Load curtailment: under contract or voluntary in response to incentives

listed may be used to reduce either daily or seasonal variations in system load.

Table 4-2 also shows two classes of customer-controlled load management. The first of these includes all those measures taken by customers to meet their own end-use requirements for energy during utility peak periods. Such measures include self-generation and energy storage. The second class includes any customer-initiated actions to either deter or curtail specific end-use loads during utility-defined peak demand intervals. These actions may be based either on some negotiated contract or agreement between the customer and utility or on the customer's voluntary response to other incentives, such as time-of-day rates.

4.6 REACTIVE LOAD

So far in this chapter we have addressed real power loads. As we saw in Chapter 3, there is another aspect of power—reactive power—which is needed by equipment that involves the use of coils or motors, and requires a magnetic field for proper operation. These devices look like an inductive load to the system and engineers refer to this effect as resulting in a lagging power factor on the system.

This reactive power can be provided from a number of sources, one of which is the generators on the electric power system. Other sources are capacitors connected between lines and the ground (called "shunt capacitors") and the capacitance effect of high-voltage cables and long-distance overhead transmission lines.

A power system will not function properly and will not remain in operation unless sufficient reactive power is available equal to the reactive loads plus the large reactive losses on the system.

Many utilities impose separate charges if the reactive load of a customer, usually one with a large motor load, exceeds certain limits.

4.7 LOSSES AND UNACCOUNTED-FOR ENERGY IN THE DELIVERY SYSTEM

All the energy that leaves the generating stations is not reflected in the bills sent to customers. In the United States, total losses vary with the electrical characteristics of the particular utility system. A reasonable estimate is that losses for all causes average about 7.5%. The difference is attributable to two issues. The first is called unaccounted-for energy. This energy is not metered by the local utility and is usually due to theft of service. In some underdeveloped countries, this category can be as much as 50% of the energy generated. The second is the electric losses in the system directly related to the electric characteristics of the delivery system. They are an important consideration when selecting new electric power policies, when locating new generating plants, when deciding what generator to run to supply the next increment of load, when deciding on the voltage level and conductor sizes for new transmission, and when deciding on the amount of voltage support to provide.

Losses occur in both lines and transformers. Line losses are directly related to the square of the value of the current (I^2R). The greater the amount of electricity the delivery system carries and the greater the distance, the greater the amount of energy lost as heat. Transformer losses are of two types: no-load loss and load loss. No-load losses are related to hysteresis and eddy-current loss in the transformer core and are independent of the current. Transformer load loss is related to I^2R. The no-load losses vary as the third to fifth power of the voltage and increase significantly when voltages are outside of the design range.

Transformer manufacturers consider the amount of losses as one element of the requirements when designing a transformer. Typically, the cost of anticipated losses is a trade-off with the capital cost to purchase the transformer. Losses can be reduced by increasing the size and, hence, the cost of a transformer. Rustebakke[51] reports that the total losses at rated transformer output amount to approximately 0.3–0.6% of the rated kilovolt-amperes of the unit. On most power systems, load losses are 60% to 70% of total losses and transformer no-load losses are from 30%–40%.

In recent years, as the wholesale electric power market has been deregulated, new dispatch procedures and the increased flow of electricity on the bulk transmission system over longer distances without a commensurate increase in transmission capacity has caused an increase in transmission losses.

[51]Homer M. Rustebakke, 1983, *Electric Utility Systems and Practices,* 4th ed., Wiley.

Recent Federal legislation has addressed various aspects of energy losses and transmission and distribution efficiencies. New appliance efficiency standards have been mandated and research is being directed at so-called smart-grid technologies.[52]

4.8 FORECASTS

To a large extent, the business of the electric power industry is driven by forecasts. Forecasts of peak electric demand are used as the basis for long-range decisions on generation, transmission, and distribution additions. Although an aggregate forecast is usually suitable for generation planning purposes, the forecast has to be disaggregated for transmission and distribution planning purposes.

Forecasts of energy requirements are also used. These forecasts can be on a sendout basis or on a sales basis. The accounting difference between sendout and sales is that sendout is the quantity measured at the output of the generators and is, in essence, in "real time." Sales data, on the other hand, is that information obtained from the meters at customer's premises and is usually the total electricity used by the customer in the prior month (or billing cycle—the period since the customer's meter was last read).

Sendout forecasts are used in the planning of generation resources since customer energy requirements determine the amount of fuel needed for generation. Sales forecasts are usually the basis of the revenue forecast needed for financial planning and rate-setting purposes.

Forecasts are usually prepared annually by taking into consideration the most recent experience. Many participants base their forecasts on presumed weather conditions, that is, a temperature and humidity standard, based, perhaps, on the weather experience in a previous number of years. The experienced peak loads and energy sendout and sales are statistically "weather normalized" and these values are used as the starting point for the forecasts.

The time horizon for peak load forecasts is driven by the planning cycle. There is no industry-wide magic horizon year for the forecast, since the planning cycle differs from area to area, driven

[52]See discussion in Chapter 8.

in large part by the time it takes to obtain state regulatory approval for new generation and transmission facilities. Generally speaking, in recent years, the lead time to construct new generation has decreased and the forecast horizon has also decreased. FERC, in its July 31, 2001, Notice of Proposed Rulemaking on Standard Market Design indicates that independent transmission service providers will be required to forecast demand for a planning horizon of 3 to 5 years. Many consider these periods to be insufficient. It is fairly common for planning organizations to use forecasts looking 10 years into the future.

Energy and revenue forecasts tend to be driven by individual system and regulatory needs. In some states rate cases are based on forecast test years, requiring sales and revenue forecasts as inputs to a projected revenue requirement analysis.

Every forecast, since it depends on assumptions, has a degree of uncertainty. The longer the period the forecast covers, the greater the uncertainty. From a planning perspective, this creates a two-edged sword—if the forecast is too low, there may not be enough generation, transmission, or distribution facilities to supply customer load; if the forecast is too high, there will be unused capacity and revenue will be less than expected, creating economic problems.

There are a number of approaches used to forecast peak demand. The most elementary being extrapolation of experienced loads. This technique assumes that the underlying customer usage pattern remains the same. This technique has applicability in short-term, day-to-day and week-to-week forecasts for operating purposes.

Forecasts can be either “top down” or “bottom up.” A top-down forecast, called an econometric model, relates the future total system load to a set of macroeconomic assumptions. A variety of statistical modeling techniques are used to relate prior load to one or more explanatory variables. Various measures of employment, gross domestic product (GDP) values, and energy prices are among the more commonly used variables. Forecasts of these variables are made and used to drive the forecast. The forecasts can be based on a single model for an entire service area or there can be a number of models for different customer classifications—residential, commercial, and so on—each with its own explanatory variables.

A weakness of this approach is that, since it assumes that the underlying electrical uses remain the same as in the past, it does not capture the impact of new technologies or of significant changes in the underlying customer usage patterns. For example, a model based on 1970 and 1980 load data would not have captured the effect on aggregate load of the large influx of personal computers experienced in the 1990s. Models based on data from even the early 1990s would not capture the trend for employees to work at home instead of in large office buildings. Going forward, the impact of charging batteries of hybrid and electric cars could potentially have a significant impact on sales and, perhaps, on peak demand.

A solution is to define the particular equipment of each customer class and its energy usage, a so-called end-use approach. The forecast relates the future load to known or assumed changes in the stock of individual energy consuming devices. A residential customer might be identified by the number and type of its appliances, its cooling and heating systems, its lighting, and so on. An aggregate consumption is developed for each customer and then for all the customers of the same type. This approach requires information on the types of appliances customers have; the electrical requirements for each, including information about its age and efficiency (to factor into the forecast the effects of appliance turnover with newer, higher efficiency devices); the types of equipment they are buying; the average time period each is used; and the coincidence factor of usage patterns between customers.

Commercial end-use modeling is more complicated than residential end-use modeling because of the complexity of the systems employed by these customers and the attendant problem of acquiring the necessary data about them. The Commend Program developed by EPRI defines twelve building types, ten end uses, and four fuel types (to allow for evaluation of the potential of substitution of alternate energy sources for electricity). The squared footage for each building type must be provided as well as an energy use per square foot. Changes in the customer base, for example, new office space coming into service, can be factored into the model.

Industrial customer end-use models are generally not used because of the variety of individual industries that comprise the sector, each one requiring its own model. For these customers, often it is best to start with prior consumption patterns and adjust them partly by reflecting the impact of future economic conditions and partly by simply asking the customers what their plans are.

Using an end-use model, the forecaster can explicitly address issues of turnover of appliances, appliance efficiencies, DSM impacts, new technology impacts, and so on. This flexibility comes at a cost: the large volume of information that is required.

Forecasts for various local regions can also be accumulated to reach total system forecasts. This bottom-up approach has the advantage of diversity of assumptions. Some forecasts may be high and some low with errors compensating. With the top-down forecasts, if a major assumption is in error the entire forecast is in error.

In some instances, a combination of techniques is used: an end-use model for residential load, an econometric model for commercial load, and an extrapolation of prior load adjusted for known changes (plant openings or closings) for industrial load. The modeling techniques selected are determined to a large extent by the size and types of the electric load, the availability of data, and the resources available to the forecaster.

CHAPTER 5

ELECTRIC POWER GENERATION AND CONCERNS ABOUT GREENHOUSE GASES

5.1 GENERATION'S ROLE

Generation is the process of conversion of energy resources to electric energy in order to be able to reliably supply customer requirements at all times. The electric power system in North America uses a wide array of energy resources and different methods or processes to convert the energy resource into electric power and electricity.

In describing the function of electric generating units, it is useful to view each unit as a complete system with input (fuel or other energy resource) and output (electrical energy).

Between the input and output are various energy conversion devices. For thermal plants, boilers, turbines, and generators convert energy contained in fuel to thermal energy (heat), thermal energy to mechanical energy, and, finally, mechanical energy to electricity. For energy sources such as water power and wind power, energy is converted into mechanical energy directly and then into electricity. For photoelectric solar energy and fuel cells, energies are converted directly to electricity.

Typically, the generation of electric power is accomplished through the coordinated operation of several hundred physical components. The specific process depends on the types and sizes of plants. Some of the more general elements of electric power generation are best understood by reviewing the various types of plants and their characteristics.

In order to operate and plan generating systems, certain types of data are usually required for analysis: capital costs; operation and maintenance expenditures; efficiency data, such as heat rates; the amount of fuel required to produce a kilowatt hour of electricity; and the cost and the availability of the energy source, such as the amount of water. Historically, when scheduling the division of load among the various generators on the system, incremental heat rates and the costs of fuel were used. For more than 80 years, this was done to minimize total production costs. Since restructuring, this information is used by the plant owners to determine their prices and maximize their profits in the selling of bulk electric power.

The assurance of sufficient capacity is another requirement for a generating system. For this purpose, knowledge of equipment breakdown data, outage data, and maintenance requirements are essential. Through the availability of such data, reliability analyses can be made to determine the adequacy of the total amount of generating capacity needed to meet the maximum demand that will be put on the system at a given time.

It is also important that generating systems have sufficient diversity in the fuels they use for generation and that each fuel type be available in storage amounts to enable the system to operate in the event of short-term fuel supply interruptions.

5.2 TYPES OF GENERATION

Generating units may be classified into four broad categories based on their mode of operation and the extent to which they are used in system operations. These are:

1. Base load
2. Intermediate
3. Peaking
4. Intermittent or unschedulable

Base load units tend to be large units with low operating costs. They are designed to operate for long periods of time at or near their maximum dependable capability. Their low operating costs result from their use of low-cost water, nuclear, and coal fuels, and/or lower heat rates (higher efficiencies) than other units in the system. For a typical region, base load generation supplies 40% to 60% of the annual maximum or annual hourly load and perhaps 60% to 70% of the annual energy requirements of the region.

Base load units are usually only shut down for forced outages or maintenance. Because of their size and complexity, these units may require from 24 hours to several days to be restarted from a cold condition. Once the decision has been made to shut down one of these units, periods of up to 24 hours may be required before another start-up may be attempted. When operating a power system, decisions on the time of restarting units play an important role in hour-by-hour schedules for generation.

Intermediate units are those generating units that are used to respond to the variations in customer demand that occur during the day. They are designed to withstand repeated heating and cooling cycles caused by changes in output levels. Intermediate units usually have lower capital costs and somewhat higher heat rates (lower efficiencies) than base load units. The intermediate load may be on the order of 30–50% of the maximum hourly load for a typical system and represents perhaps 20–30% of the annual energy requirements for the utility.

Peaking units are those generating units that are called upon to supply customer demand for electricity only during the peak load hours of a given period (day, month, and year). Combustion turbines, reciprocating engines, and small hydroelectric units comprise the majority of peaking units. These are ordinarily units with a low maximum capability (usually less than 150 MW) that are capable of achieving full load operation from a cold condition within ten minutes. Peaking units usually have the highest heat rates and lowest capital costs of the four categories of units. In addition to supplying system needs during peak load hours, they may be called upon to replace the capability of other base load or cycling units that have been suddenly removed from service due to forced outages. They generally supply about 5% of the total energy requirements of a system.

As generating units age, their efficiency and performance generally decrease. In addition, newer, more efficient, lower-operating-cost units are continuously added to a power system. These two occurrences tend to cause most generating units to be operated for fewer hours as they age.

Intermittent or unschedulable units are those whose output depends on the vagaries of nature such as wind, sunlight, water flows, or tides.[53]

Many types of generating plants are in use and possible for the future, including steam plants fueled by coal, oil, or natural gas; nuclear plants; hydro plants; and plants that use renewable energy (wind, sun, waves, geothermal, etc.). Traditionally, electric generating units are grouped by prime mover—the type of device that drives the electric generator. The major prime movers in use in the United States today are steam turbines, combustion turbines (essentially jet engines or their industrial equivalent), hydro turbines, and reciprocating or internal combustion engines (primarily in use for standby or emergency use). Looking to the future, there is a potential for a far wider range of generation types. A more general approach to classifying the various types of generation might be into classes based on the energy resources used, as illustrated in Table 5-1a, or based on the type of energy conversion process, as illustrated in Table 5-1b.

Generating units are built in sizes from a few kilowatts to over a thousand megawatts. The units driven by internal combustion engines and combustion turbines are generally at the lower end of the size scale. Gas-driven microturbines are the smallest. Steam units have been built as small as several hundred kilowatts. Present-day technologies and competitive economics are determining the best size for steam units. Refer to Table 1-1 for the number of units and the total capacity installed in the United States.

Different fuels may be used for the various types of energy conversion schemes. The source of heat can be from the burning of coal, oil, natural gas, wastes, wood, and other biologically produced combustibles, or the heat given off in a nuclear reaction. Heat can also be from a geological source or even the sun, with the solar energy concentrated with mirrors or other optical systems sufficient to create a temperature high enough to efficiently convert the solar energy into electricity through a thermal cycle. Electricity can also be generated from the mechanical energy in flowing or falling water, from wind, or through direct conversion of the energy in sunlight in a semiconductor device. Direct ener-

[53]The terminology here is not yet well established. Some intermittent resources and generators will be very predictable, whereas others will be less so. In general, these generators are intermittent, with variable output and differing degrees of predictability, and, as a consequence, may not be reliably scheduled.

Table 5-1a. Energy resources

Fossil fuel	Nuclear	Renewables
Coal	Fission	Geothermal
Natural gas	Fusion	Wind
Petroleum		Sunlight
		Photosynthesis
		Biofuels
		Photovoltaic
		Solar thermal
		Water
		Hydroelectric
		Tidal
		Hydrokinetic
		Wave

Table 5-1b. Energy conversion methods

Thermal	Direct	Alternating current—AC
Steam	Mechanical	Direct current—DC
Brayton	Electrochemical	
Otto	Photovoltaic	
Diesel	Magnetohydro-dynamic (MHD)	
Binary or combined cycle	Thermoelectric	
Other working fluids		
Combined heat and power or cogeneration		

gy conversion is also possible from a fuel in an electrochemical fuel cell.

5.3 THERMAL CONVERSION: USING FUEL AS THE ENERGY RESOURCE

Steam Cycle—Steam Turbines

The most common thermal energy conversion scheme is the steam cycle and steam turbine, whereby water and/or steam are used as the working fluid to convert energy from a heat source to mechanical work and electric power. In a steam turbine generating plant, fossil fuels (coal, oil, and natural gas) are burned in a furnace. (In a nuclear plant, heat is produced as a result of a nuclear reaction.) The heat given off by this combustion is used to heat water in a boiler to a temperature at which steam is produced. This steam (which may be as hot as 1000°F and at pressures as high as 3600 pounds per square inch) is then passed through one or more turbines.[54] Energy contained in the steam is extracted by allowing the steam to expand and cool as it passes through the turbine(s). This energy turns the blades of the turbine, which are connected to a shaft. This shaft is connected to the electric generator and rotates the coils of the magnetic field of the generator, thus producing electricity. After passing through the turbine, the steam passes through a condenser where it is cooled and becomes water for reintroduction to the boiler. To use as much of the heat energy as possible, after leaving the turbine, additional heat is extracted from the steam in feed-water heaters, heating water going to the boiler.

The functioning of a steam plant requires many pumps, fans, and auxiliary devices; particularly important are the feed-water pumps, which force water through the boilers; the forced and induced draft fans which provide sufficient air for the combustion in the boiler; and the system that injects the fuel into the boiler. Most steam turbines are limited to a maximum operating temperature of around a 1000°F, although units have been designed and operated at 1200°F.[55] Differences in the fuel used to produce heat and details of the thermodynamic cycle used result in design and equipment differences for each generating station. Figure 5-1 is a schematic of a coal-fired steam turbine power plant.

Combustion (Gas) Turbines

Combustion turbines are most often fueled by natural gas but can be fueled with some liquids. In a combustion turbine, hot gasses (an ignited fuel–air mixture) burn, are expanded through a turbine, driving a generator. Thus, the working fluid used to convert the heat into mechanical energy is a gas, in this specific case, a mixture of combustion gases.

An additional component of a combustion turbine is a compressor. This device increases the pressure of the air used in the combustion section by a factor of approximately 10. When the air is compressed in this manner, its temperature is raised and the densi-

[54]Large coal burning power plants typically have either a subcritical or a supercritical boiler. Supercritical units operate at higher temperatures and pressures than subcritical units, resulting in increased turbine efficiencies. See "Supercritical Plants to Come Online in 2009," by Nancy Spring, in the July 2009 issue of *Power Engineering* for a discussion of the advantages of supercritical boilers.
[55]Eddystone Unit 1.

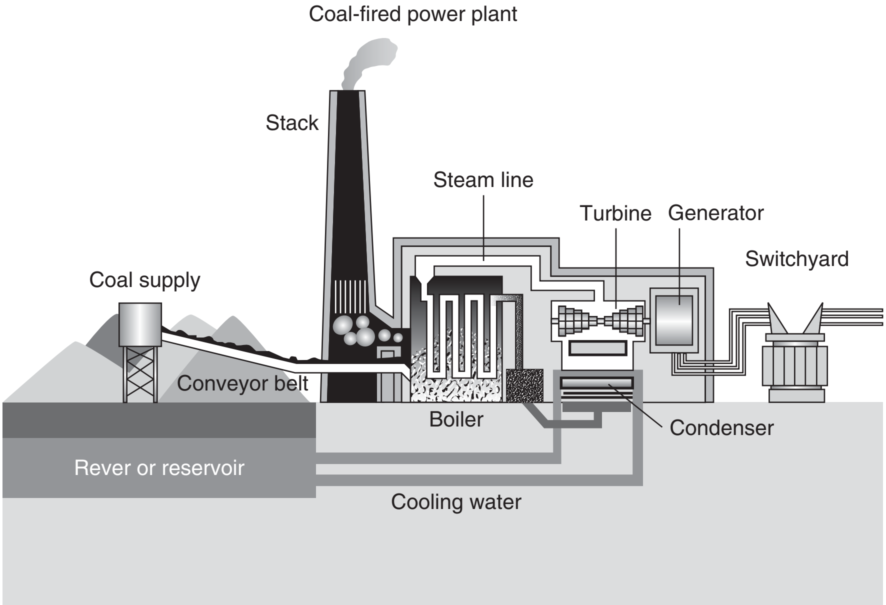

Figure 5-1. Schematic of a conventional fossil steam power plant. Source: Tennessee Valley Authority.

ty increased. The resulting combustion of the heated air and fuel mixture raises the temperature of the gas to as much as 2000°F or higher, even approaching 2400°F. This gas is then passed through a turbine where it expands and cools. The dissipated energy turns the turbine, which turns an electrical generator.

The most modern gas turbines are as efficient as steam plants and are considerably lower in capital costs. For this reason, they are often used as "peaking" plants to supply peak electricity needs. There are several variations on this basic design, each attempting to make maximum use of the energy input to the system. In some cases, the exhaust gases from the combustion turbine are used to preheat air prior to combustion. Figure 5-2 is a schematic of a combustion turbine. A plant may consist of several gas turbines and several boilers supplying steam to two or more steam turbines that drive two or more electric generators.

Combined Cycle

In other cases, the exhaust from a combustion turbine is used to heat steam in a boiler to operate with a steam turbine generator.

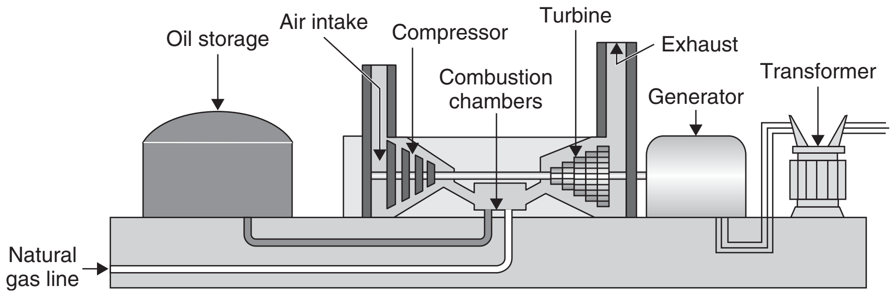

Figure 5-2. Schematic of combustion turbine power plant. Source: Tennessee Valley Authority.

This is known as a combined cycle plant. The most modern combined cycle plants have excellent efficiency, some as high as 60%, since a considerable amount of the energy in the gas turbine exhaust is recovered. Natural-gas-fired combined cycle generation plants are generally designed to operate as base load and when natural gas is lower in price are very competitive with coal fueled steam plants. Figure 5-3 is a schematic of a combined cycle power plant.

Nuclear

Nuclear units utilize a nuclear (fission) reaction as a source of heat for what is otherwise a conventional steam cycle. There are two primary designs used for nuclear reactors: boiling water reactors and pressurized water reactors. At the time of this writing, 104 nuclear power units are operating in the United States. As nuclear units age, some owners are requesting extensions of their operation licenses and it is expected that many, if not most, of the existing nuclear plants will receive extensions of the licenses to permit operation for 60 years.

No new nuclear units have been built in the United States for many years because of public opposition and concern over their capital costs and safety. As the public has become more concerned about emissions of carbon dioxide from burning of fossil fuels, nuclear is again being considered as a viable option and public attitudes have been improving. For many years, the nuclear industry has been working with the Nuclear Regulatory Commission (NRC) to develop new nuclear reactor designs and new licensing procedures to improve safety, reduce capital costs, and streamline and

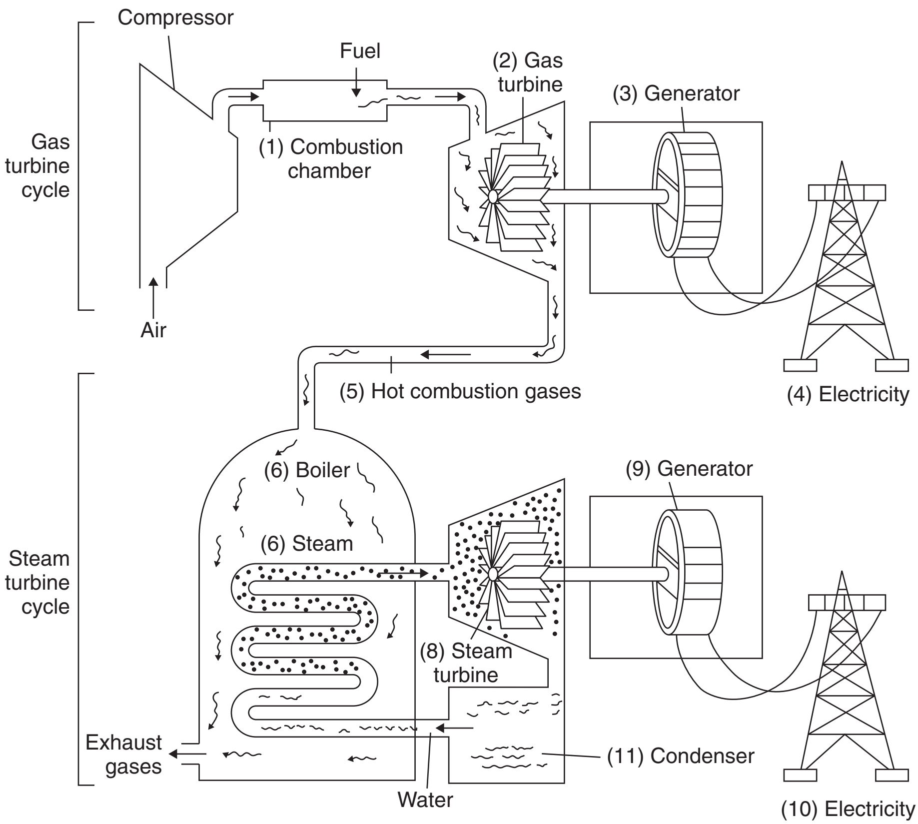

Figure 5-3. Schematic of a combined-cycle power plant. Source: Texas Utilities.

make more certain the licensing process. Licensing procedures have been streamlined and the EPAct05 included provisions encouraging the construction of new generation nuclear units. Some thirty new nuclear plants have been proposed.[56]

Reciprocating Engines

This type of generation usually consists of a large diesel engine which uses #2 diesel fuel as a source of energy, although natural gas can also be used. Electricity is produced by connecting the output shaft of the engine to an electrical generator. Diesel engine

[56]NRC website http://www.nrc.gov/. See Chapter 8 for further information on new nuclear plants.

improvements have resulted in considerable reductions in weight and improvement in efficiency. Gasoline or Otto cycle[57] internal combustion engines can also be used but these are typically seen only as emergency generators.

Microturbines

In the late 1990s, several manufacturers embarked on programs to develop and market very small versions of the gas turbine, as small as 25 kW. These small turbines, like small reciprocating internal combustion engines, can be located at or near the customers. They can be installed on the customer's side of the meter or on the distribution and subtransmission system, depending on their size. They are usually fueled from the natural gas supply available.

Combined Heat and Power (CHP) or Cogeneration

There are situations in which an industrial process can integrate the generation of electricity into its process and achieve overall higher system efficiency. These installations can be comparable in size to some fossil power plants. Typical examples include large petroleum refineries and chemical processing plants. In some cases, a waste by-product of an industrial process can be used as a fuel for electric power generation and in other cases the industrial process needs a relatively low-temperature-process heat source and this can effectively be produced as a by-product of a thermal power plant. All of these are referred to as combined heat and power or cogeneration. In some cases, it is also practical to combine electric power generation with the delivery of heat for buildings or groups of buildings, and these systems are sometimes referred to as total energy systems or district heating systems.

5.4 THERMAL CONVERSION: NONFUEL HEAT SOURCES

Geothermal

The earth itself is a valuable energy resource as natural processes within the planet generate heat; however, on average, the tem-

[57]In layman's terms, the Otto cycle describes one of the processes by which heat is converted to work. The process involves four steps: compression of a working fluid; heating at constant pressure by burning a fuel; expansion, in which the working fluid expands onto a piston; and, finally, cooling. The piston drives a shaft producing a torque.

peratures available close to the surface are too low for practical generation of electric power.[58] There are local geological conditions that make site-specific generation of electricity feasible in some regions. Of interest as an example of this resource is the Geysers fumarole area in northern California, which is a dry steam resource and has been in successful operation for many years.[59]

Solar Thermal Generation

Solar thermal generation[60] uses the direct light of the sun to produce heat in a working fluid or gas through the use of concentrating reflectors, mirrors, or other solar radiation collecting and concentrating optical derives. This solar heat source is then used in a thermal energy conversion process to produce electricity much the way electricity is generated in a fuel-driven power plant. There are then two major subsystems and the option to incorporate a thermal storage medium, perhaps simply an insulated tank of the working fluid, to provide some ability of the system to generate electricity when the direct sun is interrupted or even after sundown. The major approaches to design of the solar collector system are either a large array of concentrating mirrors directed at a collector system on a tower to achieve a high concentration of sunlight and very high temperatures, or parabolic trough collectors, which achieve a more modest temperature.

5.5 MECHANICAL ENERGY CONVERSION

Hydroturbines and Hydropumped Storage

Electric power is produced from water by directing a column of falling water past the blades of a hydraulic turbine or hydroturbine.[61] In a typical hydroelectric power plant, the water is contained behind a dam. This dam causes the level of the water to rise to large heights. As a result, potential energy is stored in the water. To produce electricity, the water is made to flow through a turbine to a lower level. The difference in elevations between the two

[58]Geothermal Energy Associates (www.geo-energy.org).
[59]Some countries, such as El Salvador, receive a substantial portion of its electricity from geothermal sources.
[60]Solar Energy Industries Association (www.seia.org).
[61]National Hydropower Association (www.hydro.org).

water levels is called the "head." In hydroelectric generation, the amount of electric energy that a given column of water is capable of producing varies directly with the head. Other approaches are in development and in recent years the term *hydrokinetic* has been adopted to refer to a broad array of devices to extract mechanical work from the motion of water.

There are several types of hydroelectric plants in use today. In the simplest form, a stream or river is diverted to pass through a hydraulic turbine. However, daily and seasonal variations in stream flow will cause the output of the hydro project to change. To deal with this situation, a dam may be constructed across the river and a reservoir created or a separate storage pond built. A portion of the stream flow is diverted into the storage facility during normal or high-flow conditions. Then, at low stream flow times, the water from the storage pond is released, thus maintaining the electric output of the project. Figure 5-4 is as schematic of a hydro turbine power plant.

In the most common configuration, the hydraulic turbines and electrical generators are located at the site of the dam. However, it is not uncommon to have the turbines and generators located several miles downstream from the dam. Under this arrangement, water flows through a large pipe or "penstock" from the dam to the turbines.

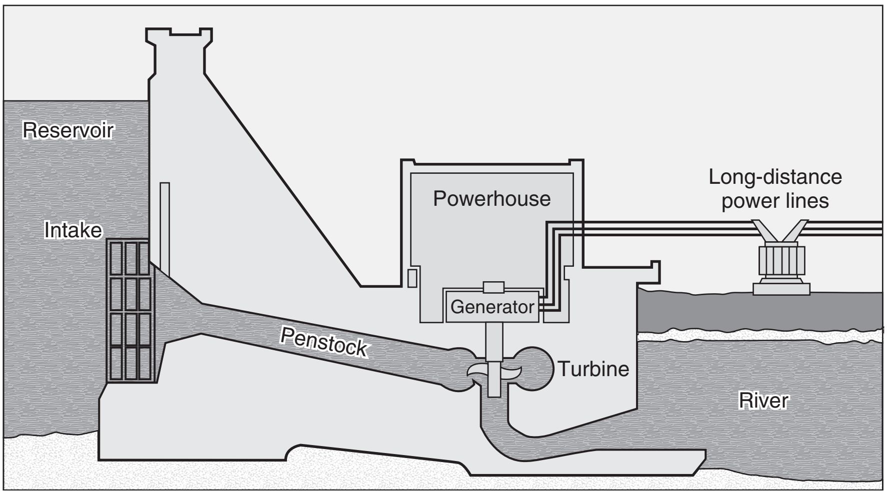

Figure 5-4. Schematic of a hydroturbine power plant. Source: Tennessee Valley Authority.

In another configuration, water in a lower reservoir is pumped to a higher elevation reservoir at night or possibly even on weekends by using low-cost electrical energy produced by the utility's thermal plants at off-peak times. During the peak-load hours, the water is released from the upper reservoir and passed through a hydroturbine or turbines, which drive electric generators. Often, these turbine generators are reversible and used to pump the water in the lower reservoir to the upper reservoir. This type of hydroelectric station is known as pumped storage.

Pumped storage plants do produce electric energy when they are generating, but, in fact, also consume energy when the water is pumped to the reservoir at the higher elevation. Only about two-thirds of the energy needed to pump the water to the higher elevation is recovered when the water is returned to the lower elevation through the hydroturbine. They also perform a relay function. They receive low-cost energy produced at one time and place, hold it for a while, and then pass it on for use at another time in other places when alternate energy sources would be more expensive. The topic of energy storage is treated later in this chapter.

Wind Turbines

Wind turbines have resurfaced in the years since the first edition of this book and while still a very small portion of the generation mix, it is expected that their use will grow significantly in the coming decades.[62] Numerous states have enacted targets for the share of electricity generated from renewable energy resources and it is expected that there will be a Federal goal or requirement of perhaps as much as 25% electricity from renewable resources by 2025. This is referred to as a Renewable Portfolio Standard (RPS). Although what passes may actually be a requirement that allows treatment of energy efficiency in end-use toward the goal, it is still a remarkable requirement and it will be a challenge to meet this goal.

Wind turbines, or more generally wind power systems, convert wind into electricity by means of a rotating turbine and a generator.[63] The technology is both old, as the use of wind turbines to provide mechanical energy goes back many centuries, and new in that the development of modern technologies emerged in the

[62]American Wind Energy Association (www.awea.org).
[63]See Chapter 8 for additional information on wind power.

1970s. Today, both onshore and offshore wind energy projects are being built worldwide, with the development of very large wind projects of hundreds or even thousands of megawatts. Individual wind turbines are typically one to two megawatts with designs that go up to as much as five megawatts. Due to the variable nature of the energy source, the speed of the wind turbine is not constant and machines other than synchronous generators have been applied. These include induction generators, DC generators, and variable reluctance generators. The further development of power electronic controls will undoubtedly result in new configurations for wind power generating systems. The effective generating capacity from wind power is considerably less than the capacity of the generators because supplemental sources are needed during periods when wind is not available.

Distributed Generation and Other Sources

There are many methods of producing electric power that presently contribute only small amounts to the total electric power production and others that have yet to prove to be of practical value. There has been a renaissance, however, in the development of many new small technologies as fuel costs have increased and the importance of energy efficiency and conservation has been recognized. These technologies use many different approaches and combinations of approaches to produce electricity.

One approach that may serve as an example is the fuel cell. The fuel cell is an electrochemical device that in its simplest configuration combines hydrogen[64] and oxygen to produce electricity, with water as the by-product. Since the conversion of the fuel (hydrogen) to electricity takes place via an electrochemical process, not through a thermal-energy-to-mechanical-energy process, the efficiencies are different than for thermal energy conversion and advocates have long argued that the fuel cell is inherently more efficient than thermal plants. However, today the most efficient combined cycle plants match the high efficiencies claimed for fuel cells. As with many of the new technologies, the capital installation costs are a significant barrier to market entry. As noted by the DOE: ". . . the most widely deployed fuel cells cost about $4500 per kilowatt; by contrast, a diesel generator costs $800 to $1500 per kilowatt, and a natural gas turbine can be $400 per kilowatt or

[64]National Hydrogen Association (www.hydrogenassociation.org).

even less"[65] A comparison of some of these small technologies is shown in Table 5-2.

5.6 RENEWABLE TECHNOLOGIES AND GREENHOUSE GAS EMISSIONS

Numerous studies have been made of the issue of global warming and the contribution that the utility industry may be making. Attention has focused on the so-called greenhouse gases (GHG): methane (CH_4), fluorinated gases, nitrous oxide (N_2O), and carbon dioxide (CO_2). Data reported by IPCC[66] indicates the airborne concentration of CH_4, CO_2, and N_2O have increased since 1750 and the level of CO_2 in 2005, 379 parts per million (ppm), is well above a natural range of 180–300 ppm. The increases in CH_4 and N_2O concentration are primarily attributed to agriculture. IPCC attributes the warming effect to these greenhouse gases.

There have been many recommendations for a variety of responses[67] to global warming including proposals for dealing with the emission of the greenhouse gases from utility boilers. Depending on the advocacy group, some can be thought of as complementary and some are not.

Supply-Side Options to Reduce Greenhouse Gas Emissions

These are:

1. Eliminate all fossil fuel generation, especially coal, and replace it with environmentally friendly generation,[68] primarily solar and wind power, and new nuclear generation.[69]

[65]Source, U.S. DOE.
[66]The International Panel on Climate Change, a scientific intergovernmental body set up by the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP): http://www.ipcc.ch/about/index.htm.
[67]See Pew Center on Global Climate Change, http://www.pewtrusts.org/our_work_category.aspx?id=112l; Environmental Defense Fund, http://www.edf.org/home.cfm; Carnegie Mellon, http://www.carnegiemellontoday.com/article.asp?aid=412&page=1.
[68]Environmentally friendly generation is often, but not always, synonymous with renewable generation.
[69]See discussion in Chapter 8.

Table 5-2. Comparison of small dispersed power production technologies*

Dispersed technology	Typical size	Cost compared to conventional plants			Environmental impact	Probable date into power systems	Comments
		Capital	Operating	Maintenance			
Small wind systems	100 W–750 kW	L	L	L	L	Now	An intermittent power source
Small-scale hydro	1 kW–15 mW	L	L	L	L	Now	Output varies seasonally; seasonal pattern may vary from year to year
Solar							
Thermal	1–10 mW	G	L	G	L	5–10 yrs	Truly intermittent; operates only during daylight; output varies with weather
Photovoltaic	1–500 kW	G	L	L	L	5–10 yrs	Same as above, also requires very large surface area
Fuel cells	5 kW–30 mW	E	L	G	L	5–15 yrs	Modular and expandable, no moving parts

Cogeneration	20–100 mW	G	L	L	Depends on fuel	Now	Electrical output typically depends on demand for thermal output
Waste-derived fuels	1–20 mW	G	L	G	Depends on emission controls	Now	Economics may require fuel cost to be “negative”
Storage							
Batteries	0–5 mW	E	L	L	L	Depends on technology	Battery life a concern
Compressed air	0–100 mW	G	E	E	E	Now	Limited site availability
Microturbines	0–5 mW	G	E	G	L	Now	Limited site availability
Diesels	0–10mW	E	E	E	G	Now	Limited site availability

*Some of the comparative data are derived from CIGRE Paper # 41-01. L = lower than, G = greater than, E = equal to.

2. Continue to use coal fired generation but use modern coal burning technology in conjunction with technology to capture and store the CO_2 (carbon sequestration).[70]

Renewables have become a major topic of discussion and a focus of many government programs as the world seeks to shift from greenhouse gas emitting energy resources to carbon-neutral and carbon-free energy sources. Yet the evaluation of renewables that are variable and intermittent in output is a difficult problem. When you build a coal or nuclear plant, you can expect it to produce electricity at its design operating point continuously, interrupted only by planned or unexpected outages, for instance, for repair. Well-engineered and constructed plants can often successfully operate more than 80% of the time, indeed, even 90%.

Such is not the case for intermittent renewables such as wind or solar photovoltaics. In addition to necessary downtime for maintenance and repair, these facilities can only generate electricity when the wind is blowing or the sun is shining. For wind, this may only be 30% of the time and for photovoltaics less than 20%, and although there is some ability to predict when the wind will be blowing and the sun shining, it is not under control of the plant operator.

Fundamental to the decision to build a new power plant is an evaluation of the value of that facility. A comparison of a conventional power plant and a renewable plant needs to take into account the intermittent nature of the wind or sun and seek to compare comparable facilities. In simple terms, the comparison can be a calculation of the total cost of electricity produced, but all the costs need to be considered, including the cost of the necessary backup generation needed when the intermittent resource is not available. This is a nontrivial task.

Preliminary analysis of the economics of wind energy as compared to other alternatives is not simple. In 2008, the U.S. Department of Energy published a report that indicated that 20% of energy requirements produced by wind on a national basis was feasible by 2030 at a reasonable cost. Other studies have indicated that the expected returns on wind power facilities will not be sufficient to encourage private capital to fi-

[70]See discussion Chapter 8.

nance such installations without significant government subsidies.[71,72]

Both wind power and solar power will need to be complemented with energy storage of some type to increase their effectiveness in meeting the reliability requirements. It will be necessary to have available reserve generation capable of rapidly responding to meet system needs when the sun or wind is not available.[73]

Each of the technologies has its own trade association that can supply additional information on the various technologies. Appropriate websites have been provided in the footnotes.

Financial Options to Reduce Carbon Emissions

There are two financial options being discussed to reduce carbon emissions:

1. Cap and trade[74]
2. Carbon tax

A cap and trade approach mirrors the approach implemented to reduce sulfur emissions which are a major cause of acid rain. The goal of reducing carbon emissions is an assumption that by doing so, global warming can be mitigated. An important difference between the reduction of sulfur and carbon emissions is that the sulfur emission issue was primarily to reduce the effects of acid rain on the Eastern United States and Canada, whereas the carbon reduction issue has a global dimension.

These financial approaches do not specify what technological approaches should be used but rely instead on a market solution to achieve a reduction of carbon emissions. The assumption is that industry, to avoid financial penalties or to earn money by selling emissions credits, will develop the necessary technologies. For the cap and trade approach, targeted emission levels are

[71]*New York Times,* February 4, 2009, "Dark Days for Green Energy," by Kate Galbraith.

[72]Fernando L. Alvarado, "Subsidies and Reserves for Renewable Energy Projects," XI SEPOPE," 17–20 March 2009, Brussels.

[73]See discussion in Chapter 8.

[74]See discussion in Chapter 16.

set for all sources such as power plants. If a plant emits less carbon than its targeted level, it can earn an emission credit that it can sell to a plant that cannot meet its targeted level. If emissions exceed a target and if a credit is not purchased to offset the overage, a cost penalty is levied. Over time, the targeted level becomes more and more restrictive. The potential financial impact on utilities and their customers under these financial approaches has given rise to significant concern, especially in areas of the country where electricity is produced by coal burning power plants.

The cap and trade approach is used in Europe and is the preferred method of the Obama administration in the United States.[75] Concerns over the approach are summarized in the Carnegie Mellon Electricity Industry Center, "Cap and Trade is Not Enough: Improving U.S. Climate Policy," which indicates that "for at least the next decade, a market-based approach alone will not induce the investments in long-lived technology needed to put the nation on a track to achieve a 50 to 80% reduction in emissions of carbon dioxide by mid-century. The range of prices for CO_2 being discussed will be too low to make this happen."[76]

5.7 CHARACTERISTICS OF GENERATING PLANTS

Some of the more common characteristics used to describe electric generating facilities are size, energy source, efficiency, type of use, and availability. These elements are certainly not all-inclusive of the information available to describe this equipment. In practice, hundreds, if not thousands, of measurements dealing with unit operation are made and/or recorded on a daily, hourly, or continuous basis. Many of these measurements describe the operation of the individual components of the generating facilities rather than the entire unit or plant.

Of overriding interest, however, are the characteristics of the overall generating plant, consisting of a collection of fuel feeders, heat producers, energy converters, exciters, and electrical genera-

[75]In late 2009, a draft energy bill containing legislation establishing a cap and trade system had been passed by the U.S. House of Representatives, but action had yet to be taken by the U.S. Senate.

[76]http://www.cmu.edu/electricity.

tors, which must be operated in order for electricity to be produced.

Size

The size of a generating unit is measured by the number of megawatts it can produce for the electric power system. The capability of the unit may be limited by any of its components, for example, by the boiler, turbine, condenser, generator, or step-up transformer. Every generating unit comes from the manufacturer with a nameplate attached to it. This "plate" gives the designed capability of the electric generator and the steam turbine. This information is not usually used in determining a generating unit's actual capability. This capability usually assumes that the generator will operate at a particular power factor, that is, in addition to real power it will also provide a certain level of reactive power to support system voltage.

At higher levels of generation, there is often a trade-off between the amount of real power and reactive power that a generator can produce. This trade-off has financial implications in the restructured industry when a generator is requested to reduce real power output in order to generate reactive power to support voltages. The relationship between the mW and mVAvar capability of generation is given in a generator capability curve, such as that shown in Figure 5-5.

Actual capability is determined by tests conducted on a regular basis, by which the output of a unit is demonstrated over a set time period. The results of these tests provide an indication of the maximum capability of the unit under normal and emergency conditions, that is, the ratings of the unit. Generator ratings also depend on ambient temperatures and temperatures of the cooling water used in the condensers of steam plants.

Depending on system conditions, such as ambient air and water temperatures, the duration of the production period, and the need for maximum capability, even at the expense of efficiency, generating units are given a number of different capability ratings, which are usually different from the generator manufacturer's nameplate rating. Normal practice provides for the establishment of net dependable capabilities and emergency capabilities for generating units. Sometimes, ratings are established for various seasons such as summer and winter, because of the effect of differ-

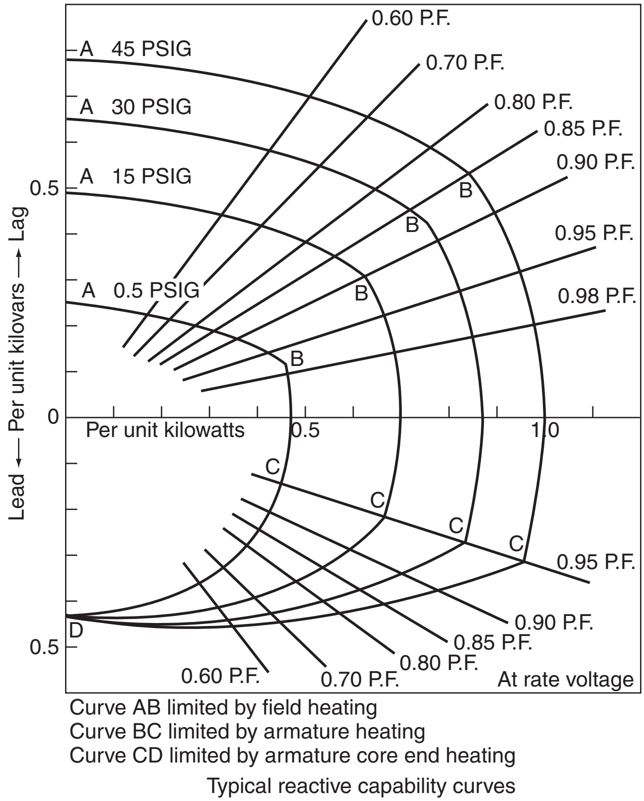

Figure 5-5. Generator capability curve. Source: Rustebakke, H. M., *Electric Utility Systems and Practices,* 4th Edition, Wiley, 1983.

ences in ambient and cooling water temperatures. Net dependable capabilities are used for normal operation and are the basis for most production costing and fuel use studies. Under emergency conditions, when extra capability is required to meet customer demand for electricity, various auxiliary devices such as feedwater heaters may be bypassed, thereby decreasing unit efficiency but increasing capability. Emergency capabilities are sometimes used for reliability calculations covering relatively infrequent occurrences of short duration.

Gross and net values may be referred to when discussing the size or capability of generating units. Gross capability is the output of a unit as measured at the terminals of the electric generator.

However, many of the pieces of equipment used to operate the generating unit, such as coal crushers and pulverizers, pumps, and building heaters, are themselves users of electric energy, typically about 5% of the unit's output in a steam plant. This electric energy is supplied by the generating unit through a special auxiliary transformer and reduces the amount of the unit's capability that can be delivered to the transmission system. This internal use of electric power is referred to as "station service" and the resulting capability that can be delivered by the plant is known as the net capability.

The net dependable capability can change with changes in cooling water temperature, ambient air temperature, atmospheric pressure, or the malfunction of a noncritical component. For example, a coal-fired generating unit has a number of pulverizers that grind the coal prior to combustion. The malfunction of one or more pulverizers could reduce the maximum fuel input and lead to a reduction in the capability of the unit. This is called a "partial outage."

The capability of a hydroelectric generating unit is determined by the size of the hydraulic turbine, the electric generator, and the height of the water (head). The volume of water does not directly affect the maximum capability of the unit or plant, but instead affects the maximum amount of energy that may be generated in a given period of time. In practice, hydro units are generally scheduled to operate when they can replace the highest cost thermal generation. If the volume of available water is limited, the amount discharged per hour must be limited in order to permit the unit to operate for a desired period of time. Thus, the capability of the unit can be effectively reduced for the period of low water conditions since the head will be reduced. When specifying the capability of hydro units, it is important to know the assumed water flow conditions on which the capability was based.

Efficiency

The thermal efficiency of a generating unit is a measure of the amount of electrical energy produced per unit of energy input and is commonly expressed as a percentage. It is important to understand that no power plant can be 100% efficient. There are physical laws that limit the efficiency of energy conversion from a fuel to electricity in a thermal power plant to be less than that of an ideal or Carnot cycle.

In the case of the British Thermal Units (BTUs) that are typically used in the United States to measure heat, the means of measuring efficiency is called the heat rate, defined as the ratio of the amount of energy in the fuel in BTUs input to a generating unit to the amount of electrical energy obtained (in kilowatt-hours).[77] The resulting value is in units of Btu/kWh. For thermal units, this ratio will change as the output level of the unit is changed. In general, the efficiency of the unit will increase (i.e., the heat rate will decrease) as the output level of the unit is increased up to the normal rating of the unit.

A generating unit that is 100% efficient would use 3412 BTUs of fuel to produce 1 kilowatt-hour of electric energy. Modern day steam units have heat rates in the 9000–10,000 Btu/kWh range. Newer combined cycles units have lower heat rates, some down to less than 7000 Btu/kWh. Dividing 3412 by the unit's actual heat rate and then multiplying by 100 will give the overall percentage efficiency of a unit. When the heat rate is multiplied by the unit cost of BTUs in the fuel, the unit cost of the energy production cost ($/kilowatt hour) can be determined.

Two kinds of heat rates are used: average and incremental. The average heat rate simply defines the amount of fuel actually consumed for each hour that the generating unit is operating at a given level of electrical output. The incremental heat rate gives the increase in thermal input required to produce an additional increment of electrical energy, also in Btu/kWh. Changes as output decreases are sometimes called the decremental heat rates. Both the incremental heat rate and the average heat rate are given in units of Btu/kWh. Therefore, it is essential that the type of heat rate be defined when requesting or providing heat rate data.

Availability

Unit availability is a characteristic that affects decisions as to the amount of generation reserve needed from both a planning and from an operating perspective. With the growth in the use of renewable energy generation, there is also a need to address the ex-

[77]A BTU is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

tent to which the availability is under the control of its owner and the extent to which its operation is schedulable or not (unschedulable).

The operation of a generating unit requires the coordinated operation of hundreds of individual components. Each component has a different level of importance to the overall operation of the generating unit. Failure of some pieces of equipment might cause little or no impairment to the operation of the unit. Still others might cause immediate and total shutdown of the unit if they fail. The failure rates of all the various components of a generating unit contribute to the overall unavailability of the unit. The unavailability of a generating unit due to component failure is known as its *forced outage rate.* It is expressed as a percentage of time and is a measure of the amount of time the unit has been or might be unavailable to supply customer demand. The nature of forced outages is that they are random occurrences over which the plant owner has little or no control. The usual definition of forced outage rate is the number of hours that the unit is forced out of service divided by the sum of the number of hours the unit is connected to the power system, plus the total number of hours that the unit is forced out of service.

There are two types of forced outages: partial and full. Partial forced outages are reductions in the capability of the unit due to failure of a component. Full forced outages occur when a critical component of the unit fails and the unit can no longer operate. This can happen in two ways: protective devices can "trip out" the unit, removing it from service; or the plant operators can shut the unit down to protect equipment or personnel. Equivalent forced outage rate (EFOR) is the term used to indicate the combination of full and prorated partial forced outage rates.

Another factor that contributes to unit availability is maintenance. Various components of generating units must be removed from service on a regular basis for preventive maintenance or to replace components before a forced outage results. Major maintenance would include turbine overhauls, rewinding of the generator, and replacing tubes in boilers (retubing), for which complete unit shutdowns are required. Any condition requiring repair that can be postponed is called a maintenance outage. If the unit must be removed from service during weekdays to repair a component problem, this is usually called a *forced outage.* Forced outages are probabilistic events whose specific occurrence cannot be predicted. Maintenance outages are deterministic events that can be scheduled in advance. This difference is important in making analyses of total generator requirements for a system.

In the real world, there are major areas of judgment and discretion involved in classifying availability data. They are often influenced by economic and reliability considerations. For this reason, compilation and analysis of availability data requires extensive judgment and experience.

Schedulable and Unschedulable Units

Fossil fuel, nuclear, and hydro (units with reservoirs) can be relied upon to provide both energy and capacity on an as-needed basis at times of peak load. A "load-serving capability" for those units is determined by multiplying their actual capacity by a factor based on their availability.

Some other types of generation cannot be scheduled at specific times, such as wind power, solar power, and run-of-river hydro units that provide energy when the primary resource is available. Although such energy is useful on the system to replace more costly energy sources and save fossil fuel, it may not be available when needed, and additional schedulable generating capacity must be provided as a backup to assure reliability. This requirement is recognized by derating such unschedulable capacity from its physical value or "nameplate" rating to the capacity that can be relied on to meet system needs. For example, the reliable capability of a wind power source may be as low as 10% of its designed nameplate rating. The resulting number is the "load-serving capability" for such sources. The use and to some extent the value of these energy resources then becomes linked to the extent to which their availability is predictable. As more experience is gained with each new resource, models are developed that can predict their availability and correlate it with load (load is also uncertain and needs to be predicted).

5.8 CAPITAL COST OF GENERATION

A key factor in selecting new generating facilities to be installed is their capital cost. The capital cost is the amount invested in the construction of the plant or any major improvements that might be made. During construction, payments for equipment and contractors must be made. Those expenditures involve interest costs[78] that must subsequently be recovered along with direct capital costs after the plant begins operating.

The combination of capital costs with those of fuel and operations and maintenance determine the total cost of producing electricity at a plant. As previously discussed, this can be determined on an average basis or an incremental basis from either a short-term or long-term perspective. Short-term incremental costs would include fuel and labor. Long-term incremental costs would include fuel, labor, and maintenance. Both the return of capital and the return on capital also must be considered in determining long-term costs.

5.9 GENERATOR LIFE EXTENSION

Most generating units are designed to have lives of 25–30 years. As units built in the past are retired, new capacity must be built to replace the capacity lost. In some cases, the cost of performing major overhauls and modifications to older units is more economic than building new capacity. The plant owners evaluate these options as part of their normal planning process. A critical issue in this regard is the environmental standards a refurbished unit must meet, either the original or new, more stringent standards. These latter standards are referred to as "new source performance standards."

5.10 THE TECHNOLOGY OF GENERATION

Synchronous Generators

Essentially all of the world's electric power is generated by synchronous generators, which have proven to be reliable and efficient devices for converting mechanical power to electric power.

[78]Recovery of some of the investment costs while a generating unit is under construction is often a contentious issue with state regulators. The terms used are allowance for funds used during construction (AFUDC) and construction work in progress (CWIP).

Since the typical power system uses alternating current (60 Hz in the United States), the chief requirement of such a device is that it produce power at a controllable voltage at a constant frequency. A typical synchronous machine consists of a rotor with a field winding and a stator with a three-phase AC winding. The rotor has a DC power supply and the stator is connected to the power system through a generator step-up transformer. The turbine rotates the field at a constant speed, often as high as 3600 RPM.

If the stator windings are connected to a load, current flows through the windings and the load. As the electrical load increases, the prime mover (turbine) must expend more mechanical energy to keep the rotor turning at a constant speed. Thus mechanical energy input by the turbine is being transformed into electrical energy. Generators in hydro plants are also synchronous machines, but rotate at lower speeds than steam units or gas turbines.

The electrical power produced by a synchronous generator is almost equal to the mechanical power input, the efficiency being in the range of 98%. The division of electric load among a number of generators is determined by a number of factors, including economics. At a given operating point, that is, at every level of generation, each turbine generator has an incremental cost, which is the cost per kilowatt-hour to generate an additional small amount of power. Maximum system economy results when all generators are operating at the same incremental cost.

The control of the real power and regulation of the speed (which must be held constant to provide a constant frequency) is done with the speed governor and automatic generator controls (AGC), and interaction with the system control center, which allocates the incremental or decremental need for generation among the generation under its control.

Variable Frequency and Direct Current Generation

New generation technologies may produce direct current or variable frequency alternating current, both of which will need to be converted to synchronous sixty cycle alternating current. Wind turbines may use variable frequency generators to effectively capture the variable power from the wind, whereas photovoltaic conversion of sunlight to electricity fundamentally produces direct current, as do fuel cells. Many different configurations of electronic devices for conversion of both variable frequency and direct current to alternating current are feasible today.

5.11 SYSTEM NEEDS AND EVALUATION OF INTERMITTENT RESOURCES

An electric power system needs to be planned, designed, and operated to meet the varying needs of its customers under varying use patterns and system outage conditions. To meet these needs reliably, the system must be able to provide its energy requirements from the available energy sources, including fuel, water, solar, and all other sources. It must also have sufficient generating capacity available to meet peak use requirements. In brief, the system must be able to meet the energy needed by its customers and the capacity required to provide power during heavy and maximum load periods.

For this reason, the various sources of electric power are rated based on the energy they can provide and the effective capacity they can provide. Both sufficient total energy resources and capacity sources are required. Additionally, there are many specific needs of the system that need to be met in the aggregate.

The introduction of large percentages of variable, unschedulable generation is a challenge to designing the system and is a matter of considerable study at this moment. NERC is currently undertaking a major study of the system needs as more intermittent resources are incorporated into electric power systems. Their efforts point to a clear need to develop a far greater understanding of these issues, in particular the need for performance standards. According to NERC, "From a bulk power system reliability perspective, a set of performance standards applying equally to all generation to interconnect resources to the utility grid is vital. In other countries, these standards are commonly referred to as 'grid codes'."[79] However, considerable work still is required to standardize basic requirements, such as:

- Power factor range (and, thus, reactive power capability)
- Voltage regulation

[79]NERC Special Report, *Accommodating High Levels of Variable Generation,* Embargoed draft, November 17, 2008.

- Fault ride-through (low voltage and high voltage)
- Inertial response (the effective inertia of the generation as seen from the grid is often zero)
- The ability to control the MW ramp rates on wind turbines and/or curtail MW output
- The ability to participate in primary frequency control (governor action, automatic generation control, etc.)

The ability and extent to which variable generation with its unique characteristics, variable nature, and technology (e.g., wind turbine technology does not use traditional synchronous generation) can provide the above functions affects the way in which they can be integrated into the power system. Grid codes should

Table 5-3. Important characteristics of electric generation

Characteristic	Comment
Efficiency Carnot cycle limitations Direct conversion	Major driver of economics for fuel-based generation resources
Location Central Distributed	Affects siting challenges, fuel delivery, and T&D requirements, as well as losses associated with transmission from generation to load
Operating Dispatchable—schedulable or not Part load characteristics Ramp rate—rate of change of output Intermittent and variable Outage rate Availability	
Economic characteristics Capital costs Operating costs Capacity factor Life expectancy	Major characteristics affecting details in cost analysis
Environmental characteristics Land Water Air Waste or byproducts Safety	

recognize the unique characteristics of all generation and be focused on the overall bulk power system performance rather than from the perspective of an individual generator. A single set of grid codes, phased in over a reasonable time frame, will provide clarity to equipment vendors regarding product design requirements and ensure efficient and economic implementation.

In summary, there are various measures to characterize generation, as shown in Table 5.3.

CHAPTER 6

THE TECHNOLOGY OF THE ELECTRIC TRANSMISSION SYSTEM

This chapter discusses the elements of the transmission system. Included in the material are descriptions of overhead and underground transmission lines and substations.

Transmission is the means by which large amounts of power are moved from generating stations, where this power is produced, to substations from which distribution facilities transport the power to customers. Transmission lines are also used to provide connections to neighboring systems. Depending on the voltage at which they operate, some transmission lines are referred to as subtransmission (see Chapter 2).

6.1 COMPONENTS

The transmission system primarily consists of three-phase alternating current transmission lines and their terminals, called *substations* or *switching stations.* Transmission lines can be either overhead, underground cable, or submarine cable. In addition to high-voltage alternating current (HVAC) lines, there are also high-voltage direct current lines (HVDC).

Transmission, subtransmission, and primary distribution lines are usually strung overhead between towers or poles. In urban settings, underground cables are used primarily because of the impracticality of running overhead lines along city streets. Although underground cables are more reliable than overhead lines

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(because they have less exposure to climatological conditions such as hurricanes, ice storms, tornadoes, etc.), they are also much more expensive than overhead lines to construct per unit of capacity and take much longer to repair because of the difficulty in finding the location of a cable failure and repairing it.

6.2 HVAC

Overhead Lines

The primary components of an overhead transmission line are:

- Conductors
- Ground or shield wires
- Insulators
- Support structures
- Land or right-of-way (R-O-W)

Conductors are the wires through which the electricity passes. Transmission wires are usually of the aluminum conductor, steel-reinforced (ACSR) type, made of stranded aluminum woven around a core of stranded steel that provides structural strength. When there are two or more of these wires per phase, they are called bundled conductors.

Ground or shield wires are wires strung from the top of one transmission tower to the next, over the transmission line. Their function is to shield the transmission line from lightning strikes.

Insulators are made of materials which do not permit the flow of electricity. They are used to attach the energized conductors to the supporting structures, which are grounded. The higher the voltage at which the line operates, the longer the insulator strings. In recent years, polymer insulators have become popular in place of the older, porcelain variety. They have the advantage of not shattering if struck by a projectile.

The most common form of support structure for transmission lines is a steel lattice tower, although wood H frames (so named because of their shape) and steel poles are also used. In recent years, as concern about the visual impact of these structures has increased, tubular steel towers also have come into use. The primary purpose of the support structure is to maintain the electricity-carrying conductors at a safe distance from the ground and from each other. Higher voltage transmission lines require greater distances between phases and from the conductors to ground than lower voltage lines and, therefore, they require bigger towers. The clearance from ground of the transmission line is usually determined at the midpoint between two successive towers, at the low point of the catenary formed by the line.

Figure 6-1 shows two transmission lines on a common right of way. The lattice tower on the left carries a single transmission line with a bundle of four conductors per phase. The tubular tower on the right carries two transmission lines with a single conductor per phase.

Overhead Line Capability—Ratings

The capability of an individual overhead transmission line (its rating) is usually determined by the requirement that the line does not exceed code clearances with the ground.[80] As power flows through the transmission line, heat is produced because of the I^2R effect. This heat will cause an expansion of the metal in the conductor and a resultant increase in the amount of its sag. The amount of sag will also be impacted by the ambient temperature, wind speed, and sunlight conditions. Ratings are usually of two types—normal and emergency—and are determined for both summer and winter conditions. Some companies average the summer and winter ratings for the fall and spring. In recent years, there has been a trend to calculating ratings for critical transmission lines on a real-time basis, reflecting actual ambient temperatures as well as the recent loading (and, therefore, heating) pattern.

Ratings are also specified for various time periods. A normal rating is that level of power flow that the line can carry continuously. An emergency rating is that level of power flow the line can carry for various periods of time: 15 minutes, 30 minutes, 2 hours, 4 hours, 24 hours, and so on.

The land that the tower line transverses is called the right-of-way (R-O-W). To maintain adequate clearances,[81] as the transmis-

[80]ANSI A300, Tree Care Operations—Tree, Shrub, and Other Woody Plant Maintenance—Standard Practices.

[81]Two considerations that impact the width of the R-O-W are the need to maintain physical separation from adjacent structures and trees and the need to minimize the impact of the transmission line's electric field on adjacent structures.

Figure 6-1. Transmission line right-of-way with two tower lines: single circuit lattice (left) and double-circuit tubular (right).

sion voltage increases, R-O-W widths also increase. In areas where it is difficult to obtain R-O-Ws, utilities design their towers to carry multiple circuits. In many areas of the country, it is not uncommon to see a structure supporting two transmission lines and one or more subtransmission or distribution lines.

There are different philosophies on the selection of R-O-Ws. One philosophy is to try to site the corridor where there is little if any visual impact to most people. The other is that the R-O-W should be adjacent to existing infrastructure such as a railroad, highways, or natural gas pipelines to minimize the overall number of corridors dedicated to infrastructure needs. Reliability concerns argue for as much separation as possible between transmission lines and between R-O-Ws to minimize exposure to incidents that might damage all lines on a R-O-W, so-called common mode failures, such as ice storms, hurricanes, tornadoes, forest fires, airplane crashes, and so on. An ongoing issue with R-O-Ws is that they must be maintained to avoid excessive vegetation growth that reduces the clearances between the line and ground.[82]

Transmission Cable

The majority of the transmission cable systems in the United States are high-pressure, fluid-filled (HPFF) or high-pressure, liquid-filled (HPLF) pipe-type cable systems. Each phase of a high-voltage power cable usually consists of stranded copper wire with oil-impregnated paper insulation. All three phases are enclosed in a steel pipe. The insulation is maintained by constantly applying a hydraulic pressure through an external oil adjustment tank to compensate for any expansion or shrinkage of the cable caused by temperature variations.

In recent years, laminated paper–polypropylene insulation has been introduced. Also, cross-linked polyethylene insulated cable (XLPE) has come into use at lower transmission voltages. Since it has no metallic sheath, it has greater flexibility and lower weight as compared with conventional paper insulated cable. Both oil-filled and XLPE cables are available today for operation at voltages up to 500 kV AC, although there is limited experience with XLPE cables operating above 220 kV.

Cable Capacity

Cable capacity is determined by concerns over the effect of heat on the cable insulation. Since the cable is in a pipe that is buried in a trench, dissipation of the I^2R heat is a major issue in cable design and operation. Cable capacity can be increased by surrounding the pipe with thermal sand that helps dissipate heat. To maintain integrity of the insulation, the splicing of cable sections is done under controlled environmental conditions. To increase the HPLF cable's capacity, the dielectric fluid can be circulated to mitigate local hot spots and to remove generated heat; air-cooled heat exchangers can be added to improve the dissipation of the generated heat from the circulated oil. At least one utility has employed a refrigeration-cooled heat exchanger.

A limitation on the application of HPLF AC cables is their high level of capacitance, causing high charging currents, which

[82]Inadequate R-O-W maintenance was a factor in the Northeast U.S. blackout of 2003.

limits the length of cable that can be used without some intermediate location where shunt reactor compensation can be installed. XLPE cables, since they do not have a metal sheath, have lower levels of capacitance.

Submarine Cables

Submarine cables are usually laid underwater in trenches with the distance between each phase measured in feet. The charging current effect limits the practical length of HVAC submarine cables. A major consideration is to have the trench deep enough and wide enough so that the cables are not damaged by anchors or fishing trawlers. The environmental impacts of dielectric fluid leaks from damaged cables are a concern. Also of concern is the need for long lengths of spare cable to facilitate repairs in the event of damage or failure. In any case, repair times will be long, possibly a month or months.

Superconducting Cables

Research and development is underway on high-temperature superconducting (HTS) cables.[83] The primary advantage of this technology is that when operated at or below a critical temperature, the cable exhibits zero resistance, resulting in zero electrical losses. Offsetting the elimination of electrical losses is the energy required to maintain the liquid nitrogen cooling environment. These cables can conduct significantly more power than conventional cables of the same dimensions.[84]

6.3 SUBSTATIONS

Substations are locations where transmission lines, transformers, and generators are connected. They fulfill a number of functions:

- Allow power from different generating stations to be fed into the main transmission corridors
- Provide a terminus for interconnections with other systems

[83]See Chapter 8.
[84]In April 2008, a 2000 foot section of HTS cable was energized as part of a 138 kV feeder on the LIPA system in Long Island, NY. www.doe.energy.gov.

- Provide a location where transformers can be connected to feed power into the subtransmission or distribution systems
- Allow transmission lines to be segmented to provide a degree of redundancy in the transmission paths
- Provide a location where compensation devices such as shunt or series reactors or capacitors can be connected to the transmission system
- Provide a location where transmission lines can be deenergized, either for maintenance or because of an electrical malfunction involving the line
- Provide protection, control, and metering equipment

Substation Equipment

There are a number of designs used for substations. However, there are elements common to all:

- A bus is the physical structure to which all lines and transformers are connected. Buses are of two generic types: open air and enclosed. Enclosed buses are used when substations are located in buildings or outdoors where space is at a premium. They involve the use of an insulating gas such as sulfur hexafluoride (SF_6) to allow reduced spacing between energized phases. Bus structures are designed to withstand the large mechanical forces that can result from fields produced by high short-circuit currents. These forces vary with the third power of the current. A bus section is the part of a bus to which a single line or transformer is connected.
- Protective relays are devices that continuously monitor the voltages and currents associated with the line and its terminals to detect failures or malfunctions in the line or equipment. Such failures are called faults and involve contact between phases or between one or more phases and ground.[85] The relays actuate circuit breakers.
- Circuit breakers are devices that are capable of interrupting the flow of electricity to isolate either a line or a transformer. They do so by opening the circuit and extinguishing the arc that forms, using a variety of technologies such as oil, vacuum, air blast, or sulfur hexafluoride (SF_6). Breakers may be in series

[85]A malfunction can also be a situation in which one phase is open without contacting ground.

with the line or transformer or may be installed on both sides of the bus section where the line connects. They allow individual lines or transformers to be removed from service (deenergized) automatically when equipment (protective relays) detects operating conditions outside a safe range. They must be capable of interrupting the very high currents that occur during fault conditions and are rated by the amount of current they can interrupt. These fault current levels can be 20 or 30 times larger than the current flow under normal operating conditions, that is, thousands of amperes.

To minimize the impact of electrical shocks to the transmission system, minimizing the total time for the relay to detect the condition and the circuit breaker to open the circuit is a critical design issue. Circuit breakers also allow lines or transformers to be removed from service for maintenance. Circuit breakers normally interrupt all three phases simultaneously, although in certain special applications, single-phase circuit breakers can be employed that will open only the phase with a problem.

- Transformers are devices that are used to connect facilities operating at two different voltage levels. For example, a transformer would be used to connect a 138 kV bus to a 13 kV bus. The transformer connects to all three phases of the bus. Physically, the transformers can include all three phases within one tank or there can be three separate tanks, one per phase. Larger capacity units may have three separate tanks because their size and weight may be a limiting factor because of transportation issues.

Transformers can be designed with two mechanisms to adjust the voltage ratio. One mechanism is the provision of more than one fixed tap position on one side of the transformer. For example, a transformer might have a nominal turns ratio of 345/138, with fixed taps on the 345 kV winding of 327.8, 336.7, 345, 353.6, and 362.3. The transformer must be deenergized to adjust the fixed tap ratio. Another mechanism is called tap changing under load (TCUL). In this mechanism, the ratio can be adjusted while the transformer is energized, providing greater operating flexibility. Some transformers have both types of mechanisms, with a fixed tap adjustment in the high voltage winding and the TCUL adjustment in the low voltage winding.

Another type transformer is an autotransformer, which is used when facilities at nearly the same voltage are to be connected, such as 138 kV to 115 kV. Rather than having two separate paths for the electricity, connected only by the magnetic flux through the transformer as in a conventional unit, the winding of autotransformer involves a tap on the higher voltage winding which supplies the lower voltage.

All larger transformers have mechanisms to remove the heat generated within the tank, involving some manner of circulating the transformer insulating/cooling oil through an external heat exchanger with fins mounted on the side of the transformer and fans to circulate air across the fins to maximize heat dissipation.

- Disconnect switches are used to open a circuit when only charging current is present. These would be used primarily to connect or disconnect circuit breakers or transformers which are not carrying load current. They are also used in conjunction with circuit breakers to provide another level of safety for workers by inserting a second opening between station equipment out of service for work and the still energized section of line or bus.
- Lightning arresters are used to protect transformers and switchgear from the effects of high voltage due to lightning strikes or switching operations. They are designed to flashover when the voltage at the transformer exceeds a preselected level that is chosen by the station design engineers to coordinate with the basic insulation level of the transformer (BIL).
- Metering equipment is provided to measure line and transformer loadings and bus voltages so operating personnel can ensure that these facilities are within acceptable limits. Metering equipment also is provided at some locations to measure the flow of energy for the billing that is required for sales and purchases of energy between various participants in the electric energy market.
- SCADA is an acronym for system control and data acquisition. It covers the measurement, telecommunications, and computing technologies that allow more and more automation of substation operations.

Depending on the electrical characteristics of a particular part of the transmission system, other types of equipment that may be located at a substation are:

- Shunt reactors (reactors connected from the energized bus to ground) are installed to control high voltages that occur especially at night due to the capacitive effect of lightly loaded transmission lines. These reactors can be energized always or they can be energized only at specific times. Shunt reactors are also used to reduce or control the high voltages that can occur when a sudden loss of a block of customer load occurs. The windings, insulation, and the external tank are similar to those used for transformers.

- Series reactors are installed in a transmission line to increase the impedance of the line, to decrease current levels in the event of short circuits, or to reduce its loading under various operating conditions.
- Shunt capacitors are installed to provide mVArs to the system to help support voltage levels.
- Series capacitors are installed to reduce the effective impedance of a transmission line. These would be installed in very long transmission lines to effectively reduce the electrical angle between the sending and the receiving parts of the system, enabling more power to flow over the line and increasing stability limits.
- Phase angle regulating transformers are installed to control power flow through a transmission line, causing more or less power to flow over desired lines. They use a variant on the design of a normal transformer, in which, due to the specialized way they are wound, they electrically inject an angular phase shift into the line. The angle can be made to either increase or decrease power flow on the line. Since they are expensive, they are usually used only on cable systems where, because of the cost and limited capacity of cables, maximum utilization of all parallel cable capacity is essential. In recent years, many of them are being installed in transmission lines to control parallel path flow, when power flows over paths in other systems not involved in transactions or which do not have adequate capacity.
- FACTS (flexible AC transmission systems) is a generic name used for a variety of devices intended to dynamically control voltage, impedance, or phase angle of HVAC lines. The development of such devices was first patented in 1975 by J. A. Casazza.[86] The development of such devices was encouraged in

[86]Casazza, J. A., March 2, 1976, Power Injector Control Means for Transmission Service, U.S. Patent No. 3,942,032.

the 1980s by a program of the Electric Power Research Institute (EPRI).[87]

These devices mirror and extend the benefits of the fixed series and shunt inductors and capacitors previously discussed in that the FACTS devices allow rapid and precise adjustments. Depending on the device, they provide a number of benefits: increased power transfer capability, rapid voltage control, improved system stability, and mitigation of subsynchronous resonance (a condition experienced in a number of regions in the United States where oscillations occur that are caused by interaction of generator control systems and the capacitance of long transmission distances). There are many devices made by many manufacturers, some of which are in the development stage and a few of which are in service. The names of the devices vary somewhat, depending on the manufacturer. The following lists some of the devices:

- Static VAr Compensators (SVCs). These devices employ fixed banks of capacitors, controlled with thyristors, which can switch them on and off rapidly. In many instances, there are also thyristor-switched inductors to prevent system resonance.
- Thyristor Controlled Series Compensators (or Series Capacitors) (TCSCs). A thyristor controlled reactor is placed in parallel with a series capacitor, allowing for a continuous and rapidly variable series compensation system.
- Static Compensators (STATCOMs). These are gate turn-off type thyristor (GTO)-based SVCs. They are solid-state synchronous voltage generators that consist of a multipulsed, voltage-sourced inverter connected in shunt with a transmission line. They do not require capacitor banks and shunt reactors but rely on electronic processing of voltage and current waveforms to provide inductive or capacitive reactive power. They have the added advantage of output that is not seriously impacted by low system voltage.
- Unified Power Flow Controller (UPFC). This device has a shunt-connected STATCOM with an additional series branch

[87] *FACTS—Flexible Alternating Transmission Systems for Cost Effective and Reliable Transmission of Electric Energy,* K. Habur, Siemens AG, and D. O'Leary, 2005, World Bank; also derived from Westinghouse Flexible AC Transmission Systems (FACTS), www.ece.umr.edu; and ABB FACTS—Flexible AC Transmission Systems, www.abb.com.

in the transmission line supplied by the STATCOM's DC circuit. The device is comparable to a phase shifting transformer. It can control all three basic power transfer parameters: voltage, impedance, and phase angle.

- SVC Light[88] STATCOM. This is based on voltage source converter technology equipped with insulated gate bipolar transistors (IGBTs), which are power switching components. It provides reactive power as well as absorption purely by means of electronic processing of voltage and current waveforms.

Substation Circuit Breaker Arrangements

Figure 6-2 shows the most commonly used bus and circuit breaker arrangements. The breaker-and-a-half design is the one most usually used in newer transmission substations since it provides excellent reliability and operating flexibility.

Transmission System Aging

Transmission systems are aging, with a large portion of the lines, cables, and substation equipment reaching average ages in excess of 30 years, and some in excess of 75 years. This has increased future failure rates and maintenance requirements,[89] causing reliability problems.

6.4 HVDC

An alternate means of transmitting electricity is to use high-voltage direct current (HVDC) technology. As the name implies, HVDC uses direct current to transmit power. Direct current facilities are connected to HVAC systems by means of rectifiers, which convert alternating current to direct current, and inverters, which convert direct current to alternating current. Early applications used mercury arc valves for the rectifiers and inverters but, starting in the 1970s, thyristors became the valve type of choice.

Thyristors, also called silicon-controlled rectifier (SCRs), are controllable semiconductors that conduct when their gates receive

[88]The ABB brand name.
[89]See Chapter 9 on Reliability.

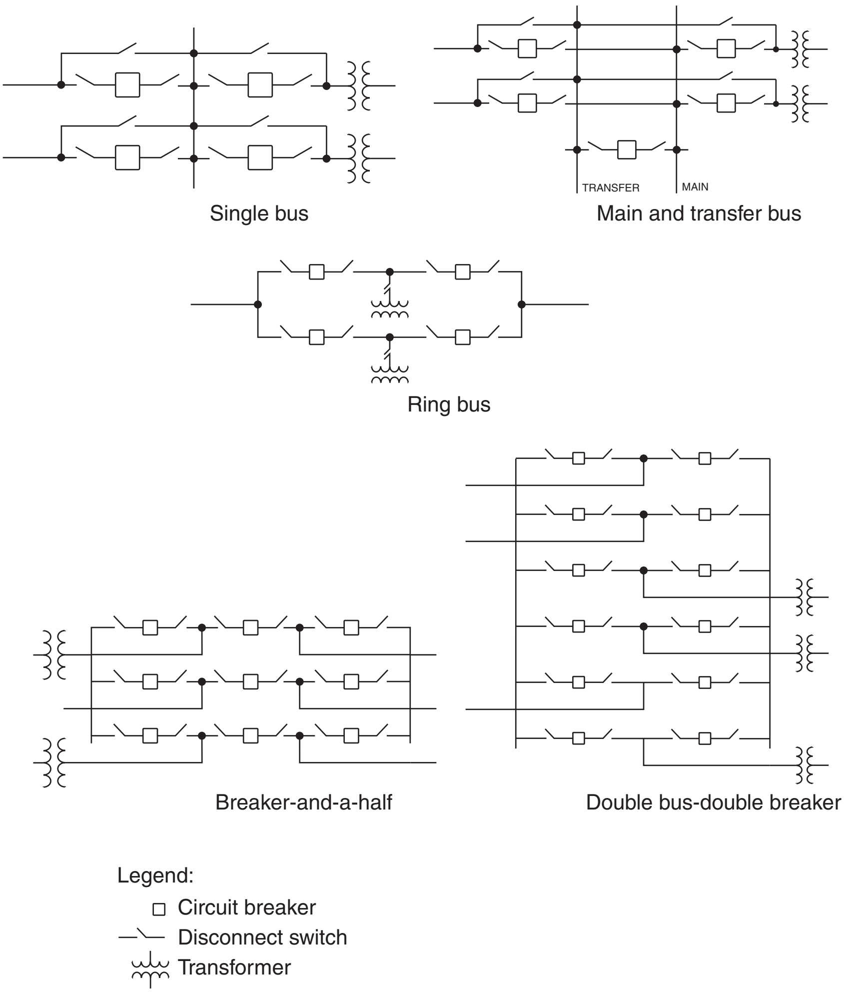


Figure 6-2. Typical substation circuit breaker arrangements. (From H. M. Rustebakke, *Electric Utility Systems and Practices,* 4th Edition, Wiley, 1984.

a current pulse. They can carry very high currents and can block very high voltages. They are connected is in series to form a thyristor valve, which allows electricity to flow during the positive half of the alternating current voltage cycle but not during the negative half. Since all three phases of the HVAC system are connected to the valves, the resultant voltage is unidirectional but with some residual oscillation. Smoothing reactors are provided to dampen this oscillation.

Recently, insulated gate bipolar transistors (IGBTs), using pulse-width modulation (PWM), have been used as valves.[90] This technology was initially developed to be used with underwater HVDC cable installations when one of the terminals is connected to a weak electrical source such as an offshore wind farm.

An IGBT is basically a bipolar junction transistor (BJT) with a semiconductor gate structure in which the gate is controlled using voltage instead of current.

HVDC transmission lines can either be single pole or bipolar, although most are bipolar, that is, they use two conductors operating at different polarities such as ± 500 kV. HVDC submarine cables are either of the solid type with oil-impregnated paper insulation or of the self-contained oil-filled type. New applications also use cables with extruded insulation made of cross-linked polyethylene.

6.5 ADVANTAGES OF AC OVER DC OPERATION

The use of AC provides a greater degree of flexibility in the design of transmission and distribution systems since it allows the use of a multivoltage-level energy delivery system. High voltages are used for the transport of large blocks of power; lower voltages are used as smaller blocks of power are delivered to local areas; and the familiar 120/240 V system is used for deliveries to individual customers. If the transmission of large amounts of electricity (or large blocks of power) were to take place using DC at the voltage levels normally found at the terminals of modern generators (13 kV to 30 kV), real power losses associated with the resistance of the transmission system would become prohibitive. Use of DC for this purpose also would require that the supply voltage be the same, or close to the same, as that required by the equipment connected to the system. Considering the variety of types and sizes of electrical equipment—motors, lights, computers, and so on—this is an impractical requirement.

Although synchronous HVAC transmission is normally preferred because of its flexibility, historically there have been a number of applications in which HVDC technology has advantages.

[90]ABB (HVDC Light) and Siemans (HVDC Plus).

Advantages of HVDC

As the technology has developed, the breakeven distance for HVDC versus HVAC point-to-point transmission lines has decreased. Some studies indicate a breakeven distance of 60 km using modern HVDC technology. Some of the advantages identified are:

- No technical limits in transmitted distance; increasing losses provide an economic limit
- Provides a means to control the magnitude and direction of the electric power flow. The power flow over an HVDC line can be controlled by adjusting the AC system voltages at the converter terminals. This provides very fast control of power flow, which allows improvements in system stability. Also, the direction of power flow can be changed very quickly (bidirectionality).
- An HVDC link does not increase the short-circuit currents at the connecting points. This means that it will not be necessary to change the circuit breakers in the existing network.
- HVDC can carry more power than HVAC for a given size of conductor.
- The need for ROW is much smaller for HVDC than for HVAC, for the same transmitted power.

Applications of HVDC technology are:

- When there is the need to transmit large amounts of power (>500 mW) over very long distances (>500 km) where the large electrical angle across long HVAC transmission lines (due to their impedances) would result in an unstable system. Examples of this application are the 1800 mW Nelson River Project where the transmission delivers the power to Winnipeg, Canada, approximately 930 km away; the 3000 mW system from the Three Gorges project to Shanghai, China, approximately 1000 km distant; and the 1456 km long, 1920 mW line from the Cahora Bassa project in Mozambique to Apollo, in South Africa. In the United States, the 3100 mW Pacific HVDC Intertie (PDCI) connects the Pacific Northwest (Celilo Converter Station) with the Los Angeles area (Sylmar Converter Station) by a 1361 km line.
- When there is the need to transmit power across long distances of water where there is no method of providing the intermedi-

ate voltage compensation that HVAC requires. An example is the 64 km Moyle interconnector from Northern Ireland to Scotland.

- When HVAC interties would not have enough capacity to withstand the electrical swings that would occur between two systems. An example is the ties between Hydro Quebec and the United States.
- When there is the need to connect two existing systems in an asynchronous manner to prevent losses of a block of generation in one system from causing transmission overloads in the other system if connected with HVAC. An example is the HVDC ties between Texas and the other regional systems.
- To connect electrical systems that operate at different frequencies. These applications are referred to as back-to-back installations. Examples are the HVDC ties within Japan connecting the 50 Hz system in Eastern Japan (including Tokyo, Yokohama, Tohoku, Hokkaido) and the 60 Hz in Western Japan (including Osaka, Kyoto, Nagoya, and Hiroshima).
- When there is a need to limit short-circuit contributors from adjacent systems since DC does not transmit short-circuit currents from one system to another.

Disadvantages of HVDC

The primary disadvantages of HVDC are its higher costs and that it remains a technology that can only be applied in point-to-point applications because of the lack of an economic and reliable HVDC circuit breaker. The lack of an HVDC circuit breaker reflects the technological problem that a direct current system does not have a point where its voltage is zero as in an alternating current system. An HVAC circuit breaker utilizes this characteristic when it opens an HVAC circuit.

With the deregulation of the wholesale power market in the United States, there is increasing interest in the use of HVDC technology to facilitate the new markets. HVDC provides much better control of the power flow and is, therefore, a better way for providing contractual transmission services. Some have suggested that dividing the large synchronous areas in the United States into smaller areas interconnected by HVDC will eliminate coordination problems between regions, will provide better local control, and will reduce short-circuit duties, significantly reducing costs.

6.6 KNOWLEDGE REQUIRED OF TRANSMISSION SYSTEMS

Those familiar with transmission system problems and policies have developed the following list, sometimes called the "ten commandments" of transmission knowledge. Thou shall understand and consider:

1. How systems are planned and operated
2. Effect of generation on transmission and vice versa
3. Causes of circulating power, parallel-path flow, and loop flow
4. Differences between individual circuit capacities and transmission/grid capacities
5. Synchronous AC connection advantages and disadvantages
6. Reactive power and its role
7. Causes and consequences of blackouts
8 Need for new technology
9. Disincentives to building new transmission
10. Need for special training and education

CHAPTER 7

DISTRIBUTION

7.1 FUNCTION OF DISTRIBUTION

The primary function of the distribution system is to connect the electric bulk power system to customers requiring service at voltages below that of the transmission system. The distribution system is the portion of the electric power system most readily seen by the customer and which contributes most directly to providing electric service.

Of the three primary functions of the electric utility—generation, transmission, and distribution—the distribution system plays the largest role in the quality of service received by the consumers. Figure 2-1 shows the relationship of the distribution system to the total system.[91] The primary components of a distribution system are:

- Distribution substation
- Primary distribution feeders
- Distribution transformers
- Secondaries and services

Transformers at the distribution substation receive electric power directly from the transmission or subtransmission system and convert it to a lower voltage for use on a primary distribution feeder. In a common configuration, a distribution substation may have several transformers and a number of primary distribution feeders emanating from it. These feeders are most commonly seen being supported by wooden utility poles on residential streets.

[91]*Wiley Encyclopedia of Energy and the Environment,* p. 459, A. Bisio and S. Boots (Eds.), Wiley, 1995.

The distribution transformer, usually on a pole, is supplied by the primary distribution feeder (primaries) and transforms the voltage of the primary feeder (2400 V through 34,500 V) to a lower voltage most commonly used by consumers. The secondary lines and service connections provide electric service directly to the ultimate consumer at the lower voltages produced at the output terminals of the distribution transformers.

7.2 PRIMARY DISTRIBUTION FEEDERS

Primary distribution voltages in the 13 kV class are the most common among U.S. utilities. The 4 kV class primary systems are older and are gradually being replaced. In some cases, 34 kV class voltages are being used in new, high-density-load areas.

Primary distribution systems use mostly a three-phase, four-wire, Y-connected arrangement for the distribution line (feeders or primaries). Under balanced operating conditions, the voltages of each phase are equal in magnitude and 120° out of phase with each of the other two phases. The fourth wire in these Y-connected systems is used as a neutral for the primary feeder, or as a common neutral when both primary and secondary feeders are present. The common neutral is also grounded at frequent intervals along the primary feeder, at distribution transformers, and at customers' service entrances.

Rural and suburban areas are usually served by overhead primary lines, with distribution transformers, fuses, switches, and other equipment mounted on poles. Urban areas with high-density loads are served by underground cable systems, with distribution transformers and switchgear installed in underground vaults or in ground-level cabinets. There is also an increasing trend toward underground single-phase primaries serving residential areas. Underground cable systems are highly reliable and unaffected by weather, but can have longer repair times. The costs of underground distribution are significantly higher than overhead.

There are three line configurations used in primary distribution systems: radial, loop, and network.

Radial Systems

The radial system is a widely used, economical system often found in low-load density areas. To reduce the duration of interruptions, overhead feeders can be protected by automatic reclosing devices located at the substation or at various locations on the feeder. These devices reenergize the feeder if the fault is temporary. To further reduce the duration and extent of customer interruptions, sectionalizing fuses are installed on branches of radial feeders, allowing unaffected portions of a feeder to remain in service.

Loop Systems

The loop system is used where a higher level of service reliability is desired. Two primary feeders form a closed loop, open at one point, so that load can be transferred from one feeder to another in the event of an outage of one circuit by closing the open point and opening at another location. One or more additional feeders along separate routes may be provided for critical loads, such as hospitals that cannot tolerate long interruptions. Switching from the normal feeder to an alternate feeder can be done manually or automatically with circuit breakers and electrical interlocks to prevent the connection of a good feeder to a faulted feeder.

Primary Network Systems

The primary network system consists of a grid of interconnected primary feeders supplied from a number of substations. It provides higher service reliability and quality than a radial or loop system. Only a few primary networks are in operation today. They are typically found in downtown areas of large cities with high load densities.

Secondary Systems

Secondary distribution is supplied by transformers from primary distribution feeders. The secondary distribution system delivers energy to customers at their utilization voltages. Table 7-1 shows typical secondary voltages and applications in the United States. There are a number of types of secondary systems. Usually, single-phase, three-wire service is provided in residential areas. One of the three wires is a ground wire and the other two are energized. Connecting to the two energized wires provides 240 V; connecting from either energized wire to the ground will supply 120 V. Each transformer supplies a separate secondary system. In many cases, there are tie points between the secondary systems so that a sup-

Table 7-1. Typical secondary distribution voltages in the United States

Voltage	Number of Phases	Number of Wires	Application
120/240 V	Single phase	Three	Residential
208 Y/120 V	Three phase	Four	Residential/commercial
480 Y/ 277 V	Three phase	Four	Commercial/industrial/high rise

ply may be obtained from an adjacent system if a transformer fails. Commercial and industrial loads are heavier than loads in residential areas, and a three-phase, four-wire supply is often installed since larger motors, used by these types of customers, use three-phase power.

To supply high-density load areas in downtown sections of cities, where the highest degree of reliability is needed, secondary networks are used. Such networks are supplied by two or more primary feeders through network transformers. These transformers are protected by devices that open to disconnect the transformer from the network if the transformer or supply feeder is faulted. Special current-limiting devices are also used at various locations in the secondary to keep problems from spreading. Smaller secondary networks called spot networks are also used to supply loads requiring extra reliability.

7.3 DISTRIBUTION CAPACITY

The capacity of the distribution system is determined in most cases by the thermal ratings of the equipment. In more rural areas with low load density, it may be determined by voltage limits. The distribution substation capacity depends on the size of transformers and the provision of an additional spare transformer. If a substation has two transformers, all load must be supplied by the remaining one if one fails. In this case, the substation capacity will depend on the capability of the remaining transformer to carry the load for the time required to replace the failed transformer, with the capacity being lower if the replacement time is longer. For substations with a single transformer, load is limited to what can be transferred to other substations at remote feeder tie points.

The allowable primary feeder loading can be limited by the size of conductors used and the characteristics of the load supplied. If the load varies, higher maximum loads can be carried by the feeder than steady loads, since the rating of the feeder depends on the heating effect of the current over time. Feeder loading may also be limited by the voltage drop that occurs at the end of long feeders.

The distribution transformer capacity is determined by the size of the transformer and the characteristics of the load. In some cases, the distribution transformers are single phase. When a three-phase supply is needed, three single-phase transformers can be used, each connected to a different phase of the three-phase primary supply. Alternatively, a three-phase transformer may be used in which the three phases are in a single tank.

The capacity of the low-voltage side of the transformer (secondaries) is determined by the size of the wires used, their length, and the characteristics of the load they supply.

7.4 LOSSES

Distribution systems have two types of energy losses: losses in the conductors and feeders due to the magnitude of the current, and transformer core losses that are independent of current. Current-related losses are equal to the current squared times the resistance of the feeder or transformer (I^2R). Accompanying these losses are reactive losses, which are given by (I^2X). The core losses result from the energy used in transformer cores as a result of hysteresis and eddy currents. These losses depend on the magnetic material used in the core. As voltages vary from the design level, core losses can vary by as much as V^3 to V^5. Core losses in a power system can exceed 3% of the power generated, constituting as much as 40% of the total loss on the system. The capacity of generation and reactive sources must be sufficient to supply these losses.

7.5 DISTRIBUTION FACILITY RATINGS

As with the ratings of transmission facilities, the ratings of distribution components are generally given as the product of the voltage at which they operate and the current flowing through them. Normally, seasonal ratings are used to recognize ambient temperature differences.

Distribution facilities are generally capable of operating at their rated value for specified periods of time for specific cycles, usually expressed as the *loss factor.* The maximum rating and the period of time over which a component may be operated at its maximum rating depend upon the ambient temperature, the wind, sunlight, and the load levels experienced just prior to the time of the peak demand.

7.6 METERING

The maximum power and energy supplied to the distribution substation and the voltage in the substation are continuously measured by recording meters in the substation. The energy used by each customer is continuously measured at the customer's meters. The electronic communication of customer meter readings to the utility for billing purposes and provision of data to assist operations and system design is increasing.

Significant changes in metering requirements have occurred as a result of the restructuring of the electric power industry to provide the ability to keep track of energy provided by various power suppliers. The use of telemetry is being increased to provide real-time data. It helps reduce interruptions and accelerates restoration of power to customers.

7.7 CONTROL OF DISTRIBUTION VOLTAGES

Good quality electric service requires that the voltage at the consumers' premises be kept within an acceptable voltage range for satisfactory operation of consumer equipment. At the 120 V level, this is 110–126 V at the utilization point. It is customary for utilities to hold voltage at the customer meter location between 114 and 126 V, which allows for a 4 V drop to the utilization point in the residence. The location of the voltage extremes are usually at the first and last customer locations on the primary feeder. During peak load conditions, the first customer usually receives the highest voltage and the last customer the lowest. The variations from light to heavy load at these locations will establish the voltage range for the circuit.

As a first step in the control of voltage on such a circuit, most utilities will regulate the primary voltage at the substation. This takes care of variations in the voltage supplied to the substation and the variation on the feeder up to the first customers. The equipment usually used for regulation are tap changers on the substation transformers or separate feeder voltage regulators. For most urban feeders, no other regulating equipment is needed, although shunt capacitor banks are often installed to supply part of the kilovar portion of the load. On larger or longer feeders, both voltage regulators and shunt-capacitor banks may be needed out on the feeders to provide supplementary voltage control and reactive supply. In general, the control of voltage is more economical if both voltage regulators and shunt capacitors are used and if distribution voltage control is coordinated with voltage control of the transmission system and of generation.

Distribution Transformers

Distribution transformers are of many types:

- Single phase or three phase
- Pole mounted or pad mounted
- Underground

They come in various sizes, usually small single-phase units, and are filled with a dielectric fluid. Figure 7-1 shows three single-

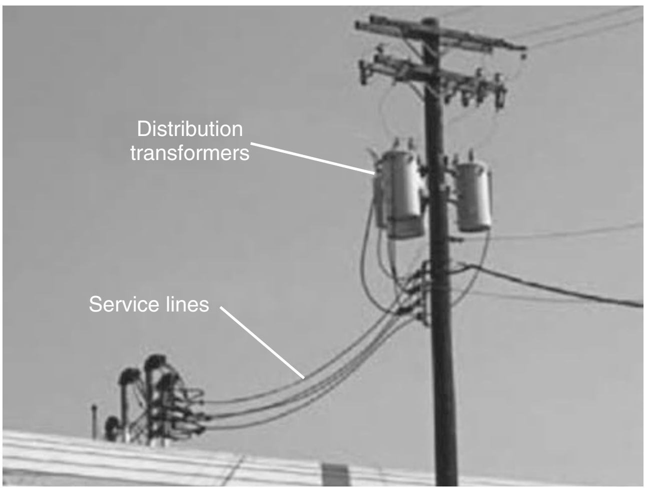


Figure 7-1. Three single-phase, pole-type transformers.

phase, pole-mounted distribution transformers supplying the service lines to a customer's premises. Figure 7-2 shows the exterior and interior of a three-phase distribution transformer. Transformers can be purchased with various efficiencies, with better efficiencies costing more.

Voltage Regulators

Voltage regulators usually are autotransformers with automatic tap changing under load. Automatic measuring and tap-changing equipment holds the output voltage within a predetermined band-

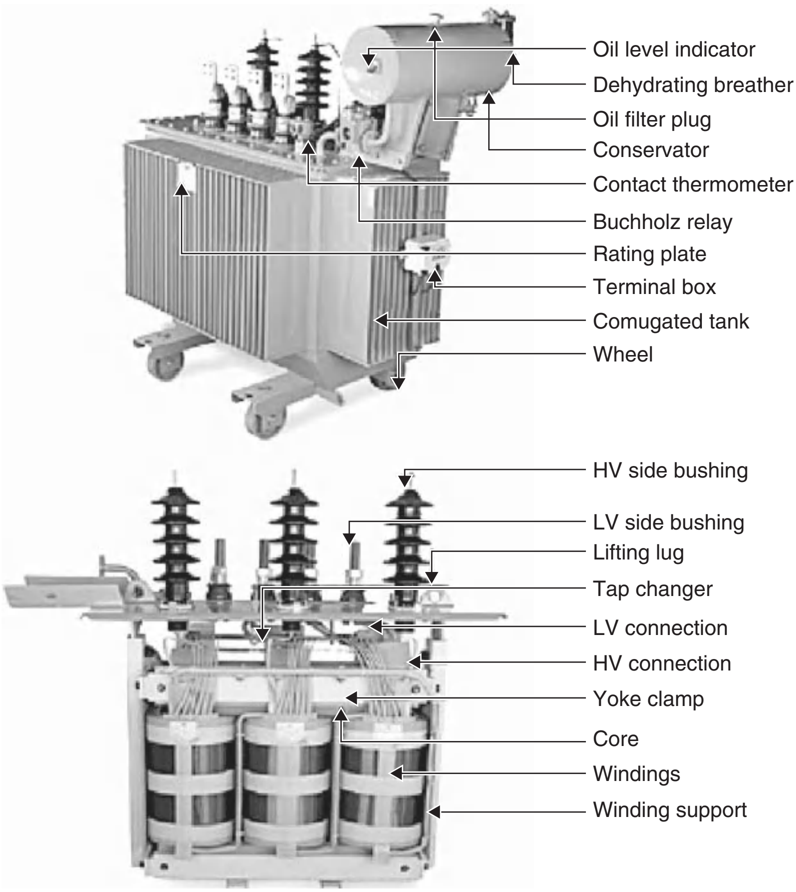


Figure 7-2. Three-phase distribution transformer. (Courtesy of Power Partners/ABB.)

width. By using the smallest practical bandwidth, more voltage drop can be allowed along the feeder while still keeping the consumer voltage within acceptable limits. The means for achieving this are an integral part of the regulator controls called line drop compensators.

Capacitors

Capacitors are applied as an economic tool to reduce system losses by supplying kilovars locally. Shunt-capacitor banks, including fixed and switched banks, are used on primary feeders to reduce voltage drop, reduce power loss, and improve power factor. The closer to the load they can be installed, the greater the economic benefit. Capacitors are not only economic tools for the distribution system, but they can eliminate the need for adding reactive sources in the bulk power system. Kilovars supplied directly to load areas reduce the current in all portions of the system. This releases transmission capacity and reduces system losses.

At light load, the capacitors installed for full-load operation may cause too high a voltage on the distribution system. Therefore, many capacitors will have to be switched off during these periods. Various means are used to perform the switching.

7.8 DISTRIBUTION SYSTEM RELIABILITY

The distribution system is that portion of the electric power system that has the greatest direct impact on the level of reliability experienced by the consumer. Outage of a major generating unit might simply cause the electric utility to buy power from neighboring utilities or start up higher cost generating equipment available on their own system. Outage of a major transmission line might cause other transmission lines within the electric utility system to pick up additional load and require a redispatch of generation. However, outage of a single distribution feeder will usually result in immediate interruption of service to consumers directly connected to that feeder.

On overhead circuits, 80–90% of the faults are of a temporary nature, caused by wind, lightening, icing, birds, small animals, and contact with tree limbs. If the fault is temporary, lasting only for a short time, the circuit can be successfully reenergized, restoring service to all consumers.

Protection of primary circuits against excessive currents is provided by circuit breakers, automatic circuit reclosers, fuses, and sectionalizers, which divide the primary circuit into a number of sections. The time–current characteristics and operating characteristics of these devices are coordinated so that service is restored to all consumers following a temporary fault, and a minimum number of consumers are interrupted for a permanent fault.

Reclosing circuit breakers and automatic circuit reclosers have both an instantaneous overcurrent characteristic and a time-delay overcurrent characteristic. Initially, these devices trip instantaneously, interrupting the fault current quickly enough to prevent the blowing or melting of downstream fuses. If the fault persists when the circuit is reclosed, these devices switch to a time-delay trip characteristic. This permits downstream fuses to blow and isolates a permanent fault before the breaker or recloser trips. Automatic reclosing is generally not used on cable circuits to prevent increasing damage from a cable fault.

Standards have been established for measuring and comparing the reliability provided to distribution customers. These are given in Chapter 10.

7.10 QUALITY OF SERVICE

Distribution systems are also subject to voltage dips and other variations in quality of service. These can be caused by the effects of other customer's apparatus or by faults or short circuits at other points on the utility's distribution system. When a fault occurs, the voltage at the fault location will go to zero. Voltages at nearby locations will be significantly depressed for the duration of the fault. Voltages will be depressed to lesser degree at more remote locations. Transmission system faults can cause dips at locations as far away as 100 miles, depending on the voltage level of the faults. These voltage dips affect digital clocks, computers, and other electronic devices and has led the industry to address improvements in the reliability and quality of service.[92]

[92]EPRI, The Cost of Power Disturbances for Industrial and Economy Companies, 2001.

7.11 DESIGN OF DISTRIBUTION SYSTEMS

A reliable distribution system must be designed to meet future power supply requirements. It must also have adequate protection for the various types of faults and short circuits that can occur. This requires that circuit breakers, fuses, and other protective devices have the ability to interrupt the very high currents that can occur when a short circuit occurs. Relaying to detect such faults needs to be provided and coordinated with the protective devices.

There is a considerable amount of software available for the design and operation of distribution systems, including:

- Capacitor placement optimization
- Circuit breaker duties
- Conductor and conduit sizing—current and temperature computations
- Database management
- Distribution reliability evaluation
- Distribution short-circuit computations
- Graphics for single-line diagrams and mapping systems
- Harmonics analysis
- Motor starting
- Power factor correction
- Power flow/voltage drop computations
- Power loss computations and costs of losses

7.12 DISTRIBUTED GENERATION

The increasing application of small generation sources on the distribution system is being driven by economics, reliability concerns, and the development of new technology. Some distributed generators will be installed by the utility on the supply side of the customers' meters. Others will be installed by the customers on their side of the meter distribution and will affect the distribution system and the other customers it supplies.

The connection of diesels, fuel cells, photovoltaic cells, wind generators, and microturbines raises new concerns and problems for distribution systems. They increase short-circuit duties, they all require relaying and protection changes, and they raise questions of safety both to utility workers and consumers.

The use of distributed generation to help provide power impacts the design and operation of bulk supply systems, including ancillary services such as reactive capacity and spinning reserve. Coordination is needed in the design and operation of the bulk supply system and the distribution system. This is complicated by the fact the bulk power and the distribution systems generally are owned by different parties and separately regulated, with the federal government regulating the bulk supply and state governments regulating the distribution systems. One alternative is the development of coordination contracts between the parties, which will provide for an equitable sharing of the benefits from coordination.

7.13 OPERATION OF DISTRIBUTION SYSTEMS

The distribution system is operated and controlled using a SCADA (system control and distribution automation) system at a dispatch center. These systems are of various types and are under

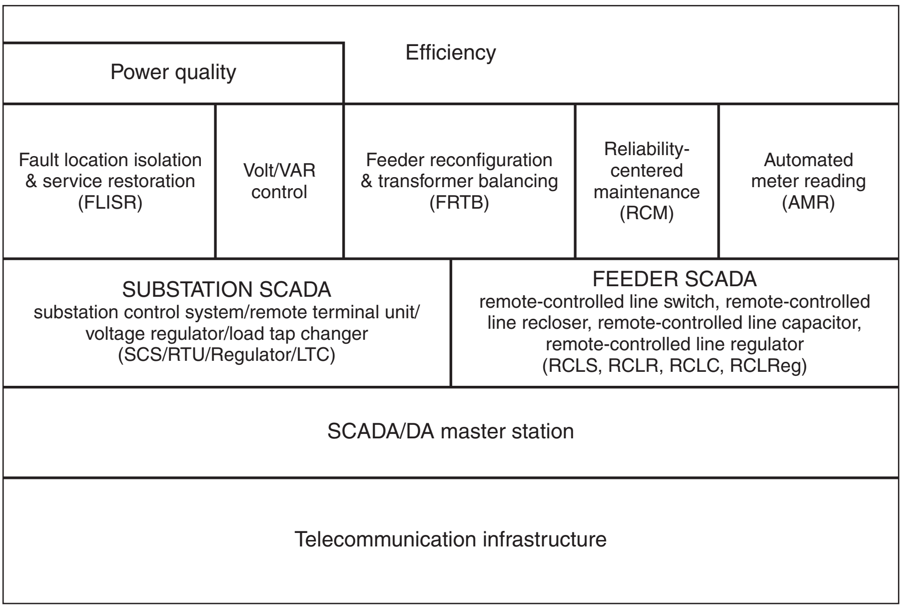


Figure 7-3. Distribution automation. From Manuel C. Mendiola, "Distribution Automation: A Strategic Option for Electric Utilities in the Restructured and Deregulated Environment," 2000, Manila Electric Company.

continuous development. They provide data needed for operation and new billing requirements.

The automation of the distribution systems continues to increase. Figure 7-3 summarizes various control options.

Benefits of distribution automation include:

- Improved distribution reliability
- Reduced customer outages and outage durations by automatically locating and isolating faulted sections of distribution circuits and automatically restoring service to the remaining sections
- Reduced customer complaints
- Reduced power losses for substation transformers, distribution feeders, and distribution transformers
- More effective use of distribution through automatic voltage control, load management, load shedding, and other automatic control functions
- Improved methods for logging, storing, and displaying distribution data
- Improved engineering, planning, operating, and maintenance of distribution

7.14 SMART GRIDS AND MICROGRIDS

Significant improvements in the management of distribution systems are envisioned in the efforts associated with development of smart grids. See Chapter 8 for a discussion of this topic.

CHAPTER 8

ENERGY STORAGE AND OTHER NEW TECHNOLOGIES

As the utility industry enters the third millennium, significant questions are being asked about its role in contributing to a self-sufficient, environmentally friendly energy policy for the United States. Activity is being focused on all aspects of the utility supply chain to improve reliability and efficiencies and to eliminate or reduce environmental impacts, including issues relating to climate change.

Much of the research activity is being driven by Federal law and financing. However, the development and application of new technologies requires time and usually large amounts of investment, often with no guarantee of success. Financing development of new large-scale technologies has always been problematical, but especially so in today's regulatory environment, where recovery of R&D investments in utility rates is uncertain. In recent years, the U.S. government has, in effect, stepped into the breach and allocated significant resources to utility-industry-related R&D.

As with any research and development activity, there are a number of caveats that apply:

- There are many potential technologies that could, if successfully developed, have significant impacts on the electric utility industry.
- For each technology, there are usually many approaches, supported by different constituencies, all seeking a share of available venture capital or government financing.
- Based on prior experience, the time to develop new technologies for the electric power industry is measureable in decades, not months or years. This is especially true for large-scale physical equipment and processes.

- Once a new technology had been successfully demonstrated, it still must overcome additional hurdles:
  - Initial capital costs to install new technology on an operational basis tend to be high and can make a project unprofitable in the short range.
  - Some utility managers tend to be conservative, waiting for some other company to be the stalking horse.

The Energy Policy Act of 2005(EPAct05) contained provisions supporting numerous technologies including:

- Technologies that avoid greenhouse gases, which might include advanced nuclear reactor designs (such as PBMR[93]) as well as clean coal and renewable energy
- Clean coal
- Wind , geothermal, and other alternative energy
- Wave and tidal power

The Energy Independence and Security Act of 2007 addressed:

- Solar and geothermal R&D
- Marine and hydrokinetic
- Carbon sequestration
- Smart Grid technologies

As discussed in Chapter 13, stimulus legislation passed in early 2009 allocated significant funding to a variety of programs directed at the utility industry, including:

- Modernization of the grid
- Fossil energy research and development
- Development of advanced batteries, including lithium ion batteries
- Biofuel projects

This latter legislation most probably will have the largest impact because of the funding levels it included. However, in many in-

[93]The pebble bed modular reactor (PBMR) is a graphite-moderated, gas-cooled, nuclear reactor. In 2006, the U.S. Department of Energy awarded the PBMR consortium the primary contract for the first phase of its New Generation Nuclear Plant (NGNP) project.

stances, the projects are not well defined, leaving it up to researchers and government officials to supply the details. As with any government financed program, there are numerous entities, with numerous proposals, seeking funding.

In this book, it would be prohibitive to try to address all potential new technologies. We focus on five:

1. Energy storage, since this technology will be an indispensible requirement if national goals of massive amounts of solar and wind power are to be realized. Additionally, storage technologies also have the potential of benefiting the T&D systems.
2. Smart Grid, since this technology has the potential to significantly impact both the economics and reliability of the power system
3. New nuclear plant designs, since nuclear produced energy is viewed as being essential for the nation to achieve its carbon reduction goals
4. Carbon sequestration and new clean coal plant designs, since coal is the most abundant indigenous resource (after sunlight and wind) and political pressures might require its use, means of making it less environmentally intrusive are essential
5. Superconductors, since this technology has the potential to impact all aspects of the delivery chain

8.1 ENERGY STORAGE

A number of the proposals for dealing with the emissions of greenhouse gases by electric utilities involve a dramatic increase in the use of wind power and solar as energy sources. For this reason, we include here a section on energy storage for the simple reason that for either of these technologies to be truly effective means must be developed and implemented to store the energy produced on a large scale. Unfortunately, the wind does not always blow and the sun does not always shine when the demand for electricity is greatest.

Benefits of Energy Storage to Generation

The value of energy storage on electric power systems has been recognized for more than 50 years. In the 1960s some anticipated the United States paying exorbitant prices for foreign oil in the future to produce electricity during the daytime, while base-load coal and nuclear generation that could have supplied this energy was not being used at night. It was obvious that if storage were available to store the coal and nuclear produced energy during the nights, it would create significant savings. In spite of these potential advantages and considerable research, the only significant energy storage system developed for electric power systems was pumped storage plants.

Fifty years ago, energy storage was considered the potential "handmaiden" for base-load nuclear and coal generation. Now, the national emphasis is on development and use of renewable technologies, such as wind and solar, technologies that often do not produce power when it is needed. The net result is that the significant portion of the generating capacity in the wind and solar generation has to be duplicated on the power system with some form of peaking generation that can be operated to provide the reliability needed by the system.[94] It is becoming increasingly evident that energy storage could be an alternative to this peaking capacity and become the "handmaiden" of solar and wind power as well as enabling us to fully utilize of our base-load nuclear and coal capacity.

Additional studies and research necessary are underway to determine the role of the specific types of storage, since each type may have different characteristics, and the amount of storage that is feasible varies in various situations. This requires analysis of the duty cycle required for the storage as increasing amounts of wind and solar power are installed. Key factors in determining the usefulness of energy storage are the shape of the system load requirements and the characteristics of the other generating capacity available. In the future, the time and magnitude of system loads could change. For example, the large-scale development of plug-in hybrid electric vehicles and the electrification of more railroads and rapid transit systems will undoubtedly cause changes in the characteristics that may help improve the capacity value of renewable resources. Research priorities are being reviewed at this time and should be helpful in arriving at these answers.

Benefits of Energy Storage to Transmission and Distribution

Energy storage applications offer potential benefits to the transmission and distribution system because of the ability of modern

[94]See discussion of "unscheduleable generating capacity" in Chapter 5.

power electronics, and some electrochemistries, to change from full discharge to full charge, or vice versa, extremely rapidly. These characteristics enable energy storage to be considered as a means of improving transmission grid reliability or increasing effective transmission capacity. At the distribution level, energy storage can be used in substation applications to improve system power factors and economics and can also be used as a reliability enhancement tool and a way to defer capital expansion by accommodating peak load conditions.

Energy storage can also be used to alleviate diurnal or other congestion patters and, in effect, store energy until the transmission system is capable of delivering the energy to the location where it is needed.

Other technical applications of electric energy storage include:

- Grid stabilization
- Grid frequency support
- Grid reserves
- Grid voltage support
- Black start

8.2 ENERGY STORAGE CONCEPTS AND TECHNOLOGIES

There are a large range of possible approaches and concepts for storing energy in electric utility systems. These are discussed in the following subsections.

Mechanical Systems

Hydropumped Storage. In hydropumped storage, water is pumped from a lower to a higher elevation. The water at the higher elevation can be stored and used to generate electricity for later utility use when it flows down through a hydroturbine to drive an electric generator. Pumping and generation may also be accomplished with a reversible pump–turbine connected to a motor–generator. The reservoirs needed for the pumped storage operation may be natural bodies of water, reservoirs of existing hydro plants or of water storage systems, especially constructed surface reservoirs, underground caverns, or a combination of these. Typical efficiency of this process is about 70%, with 30% used in the pumping–generating cycle. More than 20,000 MW of pumped storage capacity exists in the United States.

The major barriers to widespread use of conventional pumped storage are siting, geological factors, environmental and space constraints because of the large size of commercially feasible installations, and long construction times. The uncertainty and potential high costs of underground construction costs are believed to be the reason that no underground projects have been pursued to actual construction.

In underground pumped storage, the lower reservoir and power plant are located in deep underground caverns and the upper reservoir is at the surface. By being free of surface topographical restrictions, the siting of these underground plants should be considerably easier than the siting of conventional pumped storage facilities. The underground reservoir and power plant could use naturally occurring caverns, abandoned mines, or a mined-out cavern consisting of a tunnel labyrinth excavated specifically for the pumped storage reservoir. In existing mine sites, firsthand knowledge of the subsurface rock formations is available, and existing shafts can be used. With the elevation difference (head) between the upper and lower reservoirs now a variable parameter not limited by surface topography, the major design restrictions are equipment capability and rock conditions. If very high heads are used, there may be cost penalties associated with very deep mining; nevertheless, mining costs per unit of energy storage capacity should decrease with depth because of proportional reductions in the volume of the reservoir.

Underground construction and mining technologies are available and can be adapted for this system. The largest uncertainty is construction of the underground reservoir: its cost, durability with pressure cycling, and the rate of water leakage into the lower reservoir. Costs are heavily dependent upon suitability of the site and local labor conditions. The economics of scale in pumped hydro dictates sizes in the range of 1000 to 2000 MW.

Compressed Air Energy Storage. Compressed air storage uses a modified combustion turbine (split Brayton cycle), uncoupling the compressor and turbine so that they can operate at different times and incorporating the intermediate storage of compressed air. During off-peak load periods, the turbine is disengaged and the compressor is driven by the generator, which is now used as a motor and takes its power from other generating units through the system's interconnections. The stored compressed air is subsequently used during peak load periods when it is mixed with fuel in the combustion chamber, burned, and expanded through the turbine. During that period, the compressor is disengaged and the entire output of the turbine is used to drive the generator.

Since in normal operation the compressor consumes about two-thirds of the power output of the turbine, the rating of the combustion turbine operating from the stored compressed air is increased roughly by a factor of three. This permits redesign of the compressors, the combustion process, and the combustion turbine, free from the aerodynamic and thermodynamic restrictions inherent in designs of conventional combustion turbines. Current estimates for the heat rate of the combustion turbine operating from stored compressed air are in the range of 4000 Btu/kW-hr. A compression/generation energy ratio in the range of 0.65–0.75 should be readily available. The variable maintenance cost should not be any greater than that for a conventional combustion turbine.

The compressed air may be stored in naturally occurring reservoirs (caverns, porous ground reservoirs, and depleted gas or oil fields) or manmade caverns (dissolved-out salt caverns, abandoned mines, or mined hard-rock caverns). Air storage may be accomplished at variable pressure or, through the use of a hydrostatic leg, at constant pressure. Each approach has its advantages and all are applicable to different underground geologies and reservoir designs. Designs of plants in the 50–250 MW range and larger have been explored.

Compressed air storage is an old concept. Considerable interest in this concept has been expressed in Sweden, Finland, Denmark, Yugoslavia, France, and the United States. However, only two commercial units have been built: a 220 MW unit in 1977 in Huntorf, Germany and 110 MW unit with a 28 hour discharge capability in Alabama in 1991.

Research is required to investigate: (a) geological conditions for underground storage, (b) new approaches to underground cavern construction, (c) energy losses storing and moving air, (d) alternative concepts of air storage, and (e) corrosion effects on turbines from air contamination. The major uncertainties include the cost of the air storage facilities, the performance and durability of the storage facility with pressure and thermal cycling, and leakage from the storage reservoir. Also, additional geological survey work to identify the availability and number of possible sites is necessary before the future role of compressed air storage may be assessed. With the high costs of fuel and the needs of intermittent renewable resources, renewed interest in compressed air storage has developed and a concept that uses high-pressure storage in buried pipes for smaller installations is being explored.

Flywheels. Flywheels store energy in the form of the kinetic energy of a rotating mass and have been used since the beginning of the industrial age. In recent years, the commercial application of flywheels to power quality and interruptible power supplies has become a commercial reality. Technological advances in rotating machinery and high-strength materials achieved since then hold promise for longer periods and greater capacity of energy storage, which raises the possibility of new applications.

Utility system applications have been restricted to special-purpose uses for smoothing pulsed power needs or for short-duration power quality needs. Although advanced composite materials have been experimented with in test facilities and proposed for commercial application, the metal flywheel has been the one approach that is in general use. Proposed super flywheel designs deal primarily with the wheel itself, without treating the full energy storage system in sufficient detail. The large wheels once proposed for utility applications appear to be outside the size of current, state-of-the-art, cost-effective designs. Commercial applications have used steel wheels and various electromechanical machinery designs, including variable frequency converters.

Thermal Energy Storage

Thermal energy storage may be defined as storage of energy in the form of (a) sensible heat[95] and (b) the latent heat[96] associated with phase changes such as the formation of ice. The major tech-

[95]In layman's terms, sensible heat is heat (energy) applied to a substance that does not change the state of the substance, for instance, from a solid to a liquid or a liquid to a gas.

[96]In layman's terms, latent heat is heat (energy) that relates to the change of state of a substance.

nical parameters for thermal energy storage include the storage medium, the operating temperature range, and the mode of heat exchange between the storage subsystem and the heat source/sink. Any practical system must include not only the thermal energy storage and transfer subsystems but also provisions for control and insulation. Thermal energy storage can be useful in a wide spectrum of applications, including (a) hot water heating, (b) heating and air conditioning of buildings using off-peak (or solar) energy, (c) low-temperature process steam storage, (d) central station thermal storage (especially for solar–thermal power plants), and (e) industrial process heat storage and district heating systems. Depending largely on the temperature of the storage medium, these uses may be grouped into applications of low-grade (relatively low-temperature) and high-grade (high-temperature) heat.

Storage of Low-Grade Heat. Storage of sensible heat in hot water reservoirs is an established commercial practice in off-peak water heating and in chilled water applications. Heat storage in the ceramic bricks of storage heaters gained commercial acceptance in Europe several decades ago. Among the key tasks in making storage heaters practical were the design and refinement of control methods. Development resulted in improved ceramic materials of high specific heat capacity and good thermal cycling ability, new approaches to high quality thermal insulation, and extension of the concept from individual room units to central systems.

The operation of air conditioning systems with off-peak power requires coolness storage. Although coolness storage has found only limited applications, it would be a useful option if more widely applied in summer peaking electric utilities. Storage of relatively low-temperature heat will be a key requirement for the residential and commercial utilization of solar energy, and appropriate approaches have been explored experimentally. Thermal energy storage systems based on storage of latent (phase-change) heat are attractive in principle because of their high specific storage capacity. However, despite their greater volume, sensible heat storage in liquids is almost certainly more practical and economical because they avoid the problems and costs associated with heat exchangers. Storage of waste heat from power plants or industrial processes for later use is another possible application of low-grade heat storage.

Storage of High-Grade Heat. Storage of high-temperature, high-pressure steam/water mixtures is a prime example of thermal energy storage but is largely only of historical interest as a step in the development of the modern steam power plant. While the basic technologies associated with thermal storage via hot water and steam is straightforward, the large size and high costs of the storage vessels has largely ruled out this technology as part of conventional power plants. The benefit of energy storage is in conjunction with solar thermal power plants. The use of storage of sensible heat in a high-temperature oil or liquid molten salt can extend the operating hours of the power generation portion of the solar thermal power plant and result in a higher capacity factor for the plant than would be possible if the plant could only generate power when the sun was available.

Chemical Energy Storage

Chemical energy storage is the storage of energy as chemicals (usually two different chemicals that can be gases, liquids, or solids) that can be made to react with a net release of energy. Storage of energy in chemical form has two inherent advantages. The high energy density of a chemical system results in compact, generally low-cost storage and ready transportability of energy, and chemical energy is readily converted into other useful energy forms by a variety of methods and devices. These advantages are responsible for the almost exclusive use of conventional fuels for energy storage and mobility applications.

The chemical energy storage methods and systems relevant to electric power (excluding conventional fuel storage) are largely secondary battery energy storage and hydrogen storage. In general, the reactant systems containing the stored energy must be reformed readily from their reacted (discharged) state upon addition of energy in a suitable form. Although many other schemes have been proposed, they remain only of research interest at the moment.

Batteries

In "storage" batteries, the conversion from electrical to chemical energy (charging) and the reverse process (discharging) are performed by electrochemical reactions. The electric form of input and output energy, compactness, and the modular characteristics common to electrochemical devices make batteries potentially the most useful among advanced energy storage methods.

Many different electrochemical systems have been developed, or offer prospects for development, into practical storage batteries. For more than thirty years, efforts have been underway to develop and commercialize various battery systems for use by electric utilities at the scale of distributed energy storage in the size range of megawatts to tens of megawatts; several applications of lead acid batteries have actually been operated for extended periods and more advanced systems proposed and demonstrated.

Today, great interest and very substantial funding is being invested in lithium battery systems that operate at ambient temperatures and are targeted primarily for mobility and portable power, including especially the plug-in hybrid vehicle. If this current effort is successful and the promise of lower costs in large volume production is realized, practical battery energy storage may become a practical reality on a large scale, although each individual installation may be only the tens of kilowatt hours needed for the personal vehicle applications.

Hydrogen Energy Storage Systems

Hydrogen energy storage represents the best known example of advanced chemical energy storage. Several approaches have been proposed and explored for each of the required subsystems—hydrogen generation, storage, and reconversion—which can be combined in various ways into overall energy conversion and storage systems. For hydrogen generation from water, electrolysis is the only established industrial process. Current electrolysis technology is handicapped by high capital costs, but considerable potential appears to exist for development of more efficient, lower-cost electrolyzers. At present there is little commercial incentive to develop such technology.

Closed-cycle thermochemical processes are being proposed for hydrogen production via water splitting,[97] but current work is still in the conceptual and early laboratory stages. The incentive to develop such processes derives from the potential for efficiencies and economics that might be superior to those offered by electrolysis, particularly if sources of fairly high-temperature heat, such as high-temperature, gas-cooled reactors or, perhaps, focused solar

[97]A chemical reaction in which water is converted into hydrogen and oxygen.

heat, become available. Integration of these processes with nuclear heat sources and commercialization of the entire hydrogen production system are likely to require many years and large capital investments.

Hydrogen storage, the second major subsystem of hydrogen energy storage systems, can take several different forms. Storage of compressed hydrogen is technically feasible now, as is storing hydrogen in more concentrated forms as a cryogenic liquid or chemically bound in metal hydrides, and logistically attractive. However, cryogenic storage of hydrogen carries a significant efficiency penalty that is unacceptable for large-scale energy storage on utility systems, and capital cost, logistics, and safety are likely to present problems for mobile applications. The outlook is better for metal hydride storage, but development efforts are still required to establish the technical and economic characteristics of this method for hydrogen storage. Reconversion of hydrogen to electric energy can be done in fuel cells or in combustion devices (gas-fired boilers or gas turbines). The fuel cell approach offers potential for high efficiency, with 60% as a target for pure hydrogen fuel.

Hydrogen has unique potential for utilization of primary energy sources and flexible use of the stored energy. However, unless major advances result from current research and development on hydrogen production, storage, and conversion technologies, relatively low efficiency and high capital costs will be major barriers to the introduction of hydrogen energy storage systems.

Electrical Storage

Capacitors and Supercapacitors. The capacitor is an essential and elementary device in electrical circuits that stores electrical charge, typically between two metallic plates separated by dielectric, a material that is not particularly good at conducting current. The charge separation creates an electrical potential or voltage between the two plates. Capacitors are routinely used in power systems to compensate for the inductance of the electrical wires or conductors. Properly designed capacitors can withstand high voltages and are well suited to serve as static devices in high-voltage applications.

In the last two decades, a new class of capacitors—supercapacitors—have been developed and commercialized that operate on a somewhat different principal; these are electrochemical double layer capacitors. They have significantly higher charge densities than ordinary capacitors. Their properties are between those of a conventional capacitor and a battery. These devices are finding uses in situations in which a larger capacitance is needed and fast response time is desirable, but the full storage capacity of a battery is not needed. They have also been proposed as devices to be combined with batteries in some applications. The material properties of the supercapacitors are very different from those of conventional capacitors and they cannot withstand high voltages, but can be placed in series like batteries to operate at modest voltages.

Superconducting Magnetic Energy Storage

Superconductors have the apparently near magical property of having no resistance to direct current flow (no electrical losses) and, hence, the current in a closed loop of superconductor can persist indefinitely under ideal conditions. This property underlies the concept of superconducting magnetic energy storage originally proposed as a competitor to pumped storage in the early 1970s. Very large superconducting magnets have been designed with the potential to store energy on the scale only achieved in practice by hydro pumped storage. While no large system has ever been built, the concept appears feasible and a very detailed design for a modest system capable of storing some 20 mWh was engineered for the U.S. Department of Defense as part of potential future weapon systems in the 1980s and early 1990s. At a substantially smaller scale, the technology has been commercialized and used in power quality applications at the level of megawatts and discharge applications of seconds. The economics of these systems has limited their market to rather special applications and today they are not being widely used.

Power Conversion Equipment

To interface between the storage device and the system, devices are needed to convert power to and from an AC system to DC and to control its flow. Various types of power electronic systems are needed for such storage uses as power supplies, electric vehicles, and inverter/converters for various types of systems.

The power conversion system is a vital part of all energy storage systems. Its cost is significant and it can be greater than 25% of the overall energy storage system cost.

The Future for Energy Storage

At the present time, the U.S. Government is funding significant research in energy storage and the possibilities for new energy storage technologies being developed and being applied in the system are better than at any time in recent years. Most people feel that development of energy storage should be the top priority for new technologies in our electric power systems.

Specific needs of the future are:

- Identification of the potential effect of energy storage on the future electric utility systems of the United States
- Determination of the feasibility of commercialization of various energy storage systems and establishing the required key technical, cost, and environmental characteristics

8.3 SMART GRID

Smart Grid is one of a number of names used to describe a transmission and distribution network that uses modern sensing, computational, and communication technologies to improve the reliable and economic functioning of the bulk power system. Other names include Modern Grid, Intelligrid, and Future Grid. A subset of this notion is the development of microgrids, which is discussed below. The effort in this area was given U.S. governmental backing by the Energy Policy Act of 2005 (EPAct05) and by the U.S. Energy and Independence and Security Act of 2007.

Title IX, R&D, of EPAct05 included a subtitle relating to the development of

> . . . a comprehensive research, development, and demonstration program to ensure the reliability, efficiency, and environmental integrity of electrical transmission and distribution systems, which shall include:
>
> (1) advanced energy delivery technologies, energy storage technologies, materials, and systems, giving priority to

new transmission technologies, including composite conductor materials and other technologies that enhance reliability, operational flexibility, or power-carrying capability

(2) Advanced grid reliability and efficiency technology development
(3) Technologies contributing to significant load reductions
(4) Advanced metering, load management, and control technologies
(5) Technologies to enhance existing grid components
(6) The development and use of high-temperature superconductors to:
    (A) Enhance the reliability, operational flexibility, or power-carrying capability of electric transmission or distribution systems; or
    (B) Increase the efficiency of electric energy generation, transmission, distribution, or storage systems
(7) Integration of power systems, including systems to deliver high-quality electric power, electric power reliability, and combined heat and power
(8) Supply of electricity to the power grid by small scale, distributed and residential-based power generators
(9) The development and use of advanced grid design, operation, and planning tools
(10) Any other infrastructure technologies, as appropriate
(11) Technology transfer and education[98]

The effort to modernize the electric system was further addressed by Title XIII: Smart Grid, of the Energy Independence and Security Act of 2007, which declares

> It is the policy of the United States to support modernization of the nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve specified characteristics of a Smart Grid.
> . . . [T]o achieve each of the following, which together characterize a Smart Grid:
> 1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
> 2) Dynamic optimization of grid operations and resources, with full cyber-security.

[98]www.themoderngrid.org.

3) Deployment and integration of distributed resources and generation, including renewable resources.
4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
5) Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6) Integration of "smart" appliances and consumer devices.
7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
8) Provision to consumers of timely information and control options.
9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

The legislation directed the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability to establish two groups:

1. Smart Grid Advisory Committee[99]
2. Smart Grid Task Force[100,101]

To further define what is meant, it states that

> Electric grid stakeholders representing utilities, technology providers, researchers, policymakers, and consumers have worked together to define the functions of a smart grid. Through regional meetings convened under the Modern Grid

[99]". . . [W]hich shall include eight or more members appointed by the Secretary who have sufficient experience and expertise to represent the full range of smart grid technologies and services, to represent both private and non-Federal public sector stakeholders."
[100]Its members will include employees from the Office of Electricity Delivery and Electric Reliability and representatives of FERC and the National Institute of Standards and Technology.
[101]http://www.oe.energy.gov/smartgrid_taskforce.htm.

Strategy project of the National Energy Technology Laboratory (NETL), these stakeholders have identified the following characteristics or performance features of a smart grid:

- Self-healing from power disturbance events
- Enabling active participation by consumers in demand response
- Operating resiliently against physical and cyber attack
- Providing power quality for 21st century needs
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

A report prepared for the U.S. DOE[102] states what a Smart Grid is not:

> Devices such as wind turbines, plug-in hybrid electric vehicles and solar arrays are not part of the Smart Grid. Rather, the Smart Grid encompasses the technology that enables us to integrate, interface with and intelligently control these innovations and others.

The Smart Grid can perhaps be described as any activity that might improve the performance and efficiency of the electric power system. Those applications being discussed seem to fit into two broad categories:

1. Those impacting the operation and control of the bulk power system
2. Those impacting the distribution system, especially activities that would involve interaction with the customer and the customer's electric devices

Besides addressing technical issues, substantive public policy issues also need attention, especially for those technologies that would alter or change the usage pattern of customers. Besides developing the technical tools to optimize the operation of the power grid, efforts to adjust customer demand need to be carefully reviewed to ensure that the rights of citizens/consumers are not compromised.

There are too many entities involved in various aspects of technologies that could be implemented to modernize the grid to

[102]The Smart Grid: An Introduction, www.oe.energy.gov/SmartGridIntroduction.html.

list in this book. We suggest a Google search for specific areas of interest.

Microgrids

Microgrids are a subset of the effort to develop Smart Grid technology. They are entities that coordinate distributed energy resources in a decentralized way so as to reduce the need for control from a centralized location; for example, small commercial areas managed as one entity. These distributed resources can include various forms of distributed generation, heat and electricity storage, and controllable customer loads. The microgrid may or may not be connected to the local grid. Besides technical issues, there are also regulation/policy issues that must be addressed when implementing this technology.[103]

8.4 NEW NUCLEAR PLANT DESIGNS

After a hiatus of well over two decades, the Federal government and private industry have started taking steps to reintroduce new nuclear plant technologies into the nation's electric power industry. This development is triggered by concerns about global warming and the perspective that nuclear power could be part of a solution. However, substantial obstacles need to be addressed, including public perception of nuclear safety and the need for a long-term, viable plan to deal with nuclear waste and by-products.[104]

In the period when no new nuclear plants were built or even under development in the United States, foreign countries and manufacturers continued with their nuclear developments. This means that there are newer nuclear plant designs available and in service elsewhere, which could be included into the U.S. power system.

The nuclear industry categorizes reactor designs in various classes or generations. Figure 8-1 is a DOE diagram depicting

[103]Some groups are active in this area are: CERTs–Consortium for Electric Reliability Technology Solutions, μGrid Analysis Tool (μGrid) an effort headed by Georgia Tech, Distributed Energy Resources Customer Adoption Model (DER_CAM), an effort of the Berkeley Lab.

[104]See comment on waste storage in Chapter 1.

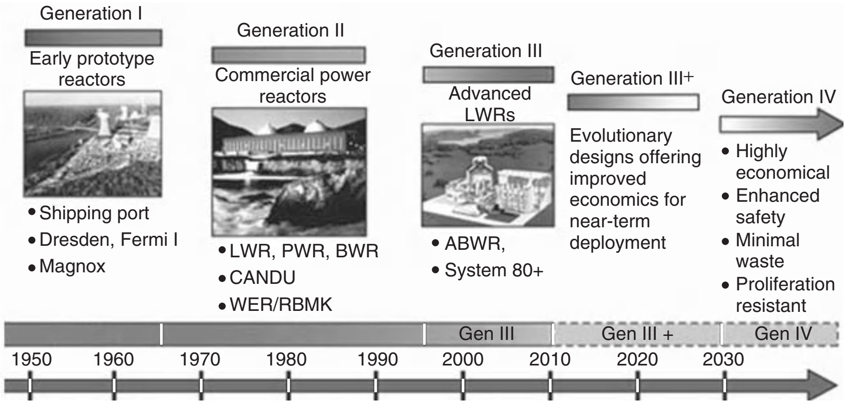


Figure 8-1. Generations and time line of different nuclear plant designs. Source: www.ne.anl.gov/research/ardt/genv/index.html.

these various generations. Table 8-1 provides information on various commercial new reactor designs. The following material illustrates the number of nuclear plants designs available, under development, or being researched. It would be impractical to include characteristics of each in this text. URL links are provided in Table 8-2 to online sources containing more technical details on each.

Generation III reactors include:

- Advanced Boiling Water Reactor (ABWR), A GE design
- Advanced Pressurized Water Reactor (APWR), A Mitsubishi Heavy Industries design

Generation III+ reactors designs are those which offer significant improvements in safety and economics over the Generation III advanced reactor designs certified by the NRC in the 1990s. These designs include:

- Advanced CANDU Reactor (ACR)
- AP1000
- European Pressurized Reactor (EPR)
- Economic Simplified Boiling Water Reactor (ESBWR)

EPAct05 provided major incentives for new near-term commercial reactor construction, and it authorized funding for the U.S. Generation IV program to build a demonstration high-temper-

Table 8-1. New commercial reactor designs

Reactor design	Vendor	Approximate capacity (MWe)	Reactor type	Certification status	Target certification
AP600	Westinghouse	650	PWR	Certified	Certified
AP1000*	Westinghouse	1117	PWR	Certified	Certified
ABWR*	GE et al.	1371	BWR	Certified	Certified
System 80+	Westinghouse	1300	PWR	Certified	Certified
ESBWR*	GE	1550	BWR	Undergoing certification	2007
EPR*	AREVA NP	1600	PWR	Precertification	2009
PBMR	Westinghouse, Eskom	180	HTGR	Precertification	Not Available
IRIS	Westinghouse et al.	360	PWR	Precertification	2010
US APWR	Mitsubishi	1600	PWR	Undergoing certification	2011
ACR Series	AECL	700–1200	Modified PHWR	Precertification	Not Available
GT-MHR	General Atomics	325	HTGR	Research prototype planned	Not Available
4S*	Toshiba	10–50	Sodium-cooled	Potential construction	Not Available

*Source EIA: www.eia.gov.

ature reactor at Idaho National Laboratory to produce electricity and hydrogen.

> The Generation IV program is focused on very high temperature reactor technologies for use in a Next Generation Nuclear Plant (NGNP) to produce hydrogen and other energy products, and on readying technologies that will further improve the economic and safety performance of existing LWR and advanced Gen IV reactor concepts.[105]
>
> Work being done by the DOE focuses on design concepts for the Very High Temperature Reactor (VHTR), a helium-cooled reactor designed to produce thermally efficient electricity and hydrogen. In total, R&D for the project is being conducted on six different models, including the DOE VHTR model.[106]

[105]DOE Report, Next Generation Nuclear Energy: http://www.ne.doe.gov/pdfFiles/factSheets/NextGenerationNuclearEnergy.pdf.
[106]See article at http://energy.ihs.com/news/nuclear-power/2005/asme-generation-iv-reactor-111405.htm.

Table 8-2. URL sites for new nuclear plant design information

- Pressurized Water Reactors (PWR):
  www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/pwr.html
- Boiling Water Reactors (BWR): www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/bwr.html
- Pressurized Heavy Water Reactors (PHWR):
  http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/china/candu.html
- High-Temperature Gas-Cooled Reactors (HTGR):
  http://www.nuc.berkeley.edu/designs/mhtgr/mhtgr.GIF
- Advance Passive 600 (AP600)
  http://www.ap600.westinghousenuclear.com/
  http://www.nei.org/index.asp?catnum=3&catid=704
- Advanced Passive 1000 (AP1000)
  http://www.nrc.gov/reactors/new-licensing/design-cert/ap1000.html
  http://www.ap1000.westinghousenuclear.com/
  http://en.wikipedia.org/wiki/AP1000
  http://www.nei.org/doc.asp?docid=770
- Advanced Boiling Water Reactor (ABWR)
  http://www.gepower.com/prod_serv/products/nuclear_energy/en/new_reactors/abwr.htm http://en.wikipedia.org/wiki/ABWR
  http://www.nei.org/doc.asp?catnum=&catid=&docid=110&format=print
  http://np2010.ne.doe.gov/reports/Main%20Report%20All5.pdf
  http://www.nuc.berkeley.edu/designs/abwr/abwr.html
- System 80+
  http://www.nei.org/index.asp?catnum=3&catid=703
  http://www.nuc.berkeley.edu/designs/sys80/sys80.html
- Economic or European Simplified Boiling Water Reactor (ESBWR)
  http://www.nrc.gov/reactors/new-licensing/design-cert/esbwr.html
  http://www.gepower.com/prod_serv/products/nuclear_energy/en/new_reactors/esbwr.htm
  http://en.wikipedia.org/wiki/ESBWR
  http://www.nei.org/index.asp?catnum=4&catid=907
  www.ans.org/pubs/magazines/nn/docs/2006-1-3.pdf
- Evolutionary Pressurized Reactor (EPR)
  http://www.nrc.gov/reactors/new-licensing/design-cert/epr.html
  http://en.wikipedia.org/wiki/European_Pressurized_Reactor
  http://unistarnuclear.com/
- Pepple Bed Modular Reactor (PBMR)
  http://www.nrc.gov/reactors/new-licensing/design-cert/pbmr.html
  http://www.pbmr.com/
  http://en.wikipedia.org/wiki/Pebble_bed_modular_reactor
  http://www.nei.org/index.asp?catnum=3&catid=707

Source: DOE.

In 2002, six Generation IV systems were identified[107]:

- Very-High-Temperature Reactor (VHTR): a graphite-moderated, helium-cooled reactor with a once-through uranium fuel cycle
- Supercritical-Water-Cooled Reactor (SCWR): a high-temperature, high-pressure, water-cooled reactor that operates above the thermodynamic critical point of water
- Gas-Cooled Fast Reactor (GFR): features a fast-neutron-spectrum, helium-cooled reactor and closed fuel cycle
- Lead-Cooled Fast Reactor (LFR): features a fast-spectrum lead or lead/bismuth eutectic liquid-metal-cooled reactor and a closed fuel cycle for efficient conversion of fertile uranium and management of actinides
- Sodium-Cooled Fast Reactor (SFR): features a fast-spectrum, sodium-cooled reactor and closed fuel cycle for efficient management of actinides and conversion of fertile uranium
- Molten Salt Reactor (MSR): produces fission power in a circulating molten salt fuel mixture with an epithermal-spectrum reactor and a full actinide-recycle fuel cycle

The DOE indicates that

> The goal of the Generation IV Nuclear Energy Systems Initiative is to address the fundamental research and development (R&D) issues necessary to establish the viability of next-generation nuclear energy system concepts and investigate the application of the R&D results to extend the operating life of existing light water reactors (LWR). Successfully addressing the fundamental R&D issues of Gen IV concepts that excel in safety, sustainability, cost-effectiveness, and proliferation-resistance, will allow these advanced reactor concepts to be considered for future commercial development and deployment by the private sector.

8.5 CARBON SEQUESTRATION AND CLEAN COAL TECHNOLOGIES

The development of newer coal-fired boilers for generating stations that are more efficient than existing technologies and that

[107] "Generation IV Nuclear Energy Systems," presented at the American Nuclear Society's 2002 Winter Meeting: http:gif.inel.gov/roadmap/pdfs/gen_iv_nuclear_energy_system.pdf.

emit fewer pollutants (sulfur, nitrogen, and mercury), and the development of systems that can capture the carbon dioxide from the flue gas after combustion of a fossil fuel and store it (carbon sequestration) are intertwined.

Since the early 2000s, the DOE has had a Clean Coal Power Initiative underway with which the government is providing cofinancing for new coal technologies.

The FutureGen project is a government–private industry partnership intended to develop a system to reduce the costs of carbon capture and sequestration. It plans on using a commercial-scale integrated gasification-based plant (IGCC). In this process, coal is gasified, which, it is envisioned, will simplify the capturing of carbon dioxide (CO_2).[108] In early 2009, government concern about the escalating cost of the project became an issue.

Figure 8-2, from the FutureGen Alliance, demonstrates the types of lead times required for a large-scale coal project.

A significant issue is how to dispose of the captured CO_2. Direct and indirect sequestration options are being considered.

> The direct options involve the capture of CO_2 at the power plant before it enters the atmosphere coupled with "value-added" sequestration, such as using CO_2 in enhanced oil recovery (EOR) operation and in methane production from deep unmineable coal seams. "Indirect" sequestration involves research on means of integrating fossil fuel production and use with terrestrial sequestration and enhanced ocean storage of carbon.[109]

The hoped-for benefits of advanced carbon sequestration technologies are staggering. The DOE reports that

> Using present technology, estimates of sequestration costs are in the range of $100 to $300/ton of carbon emissions avoided. The goal of the program is to reduce the cost of carbon sequestration to $10 or less per net ton of carbon emissions avoided by 2015. Achieving this goal would save the U.S. trillions of dollars.

[108]See http://www.futuregenalliance.org/ for information abut the project and its status.
[109]Source, DOE.

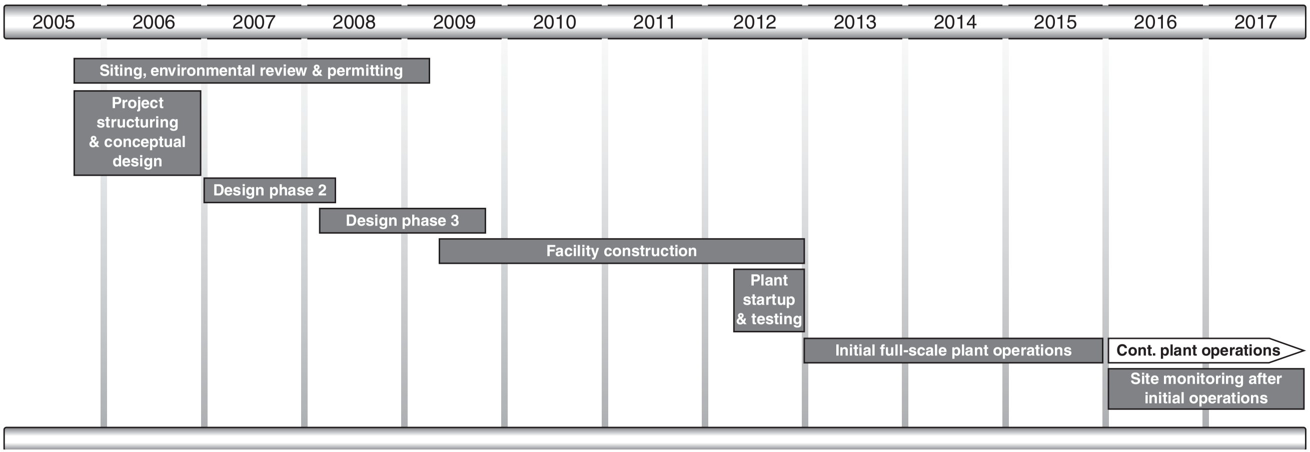


Figure 8-2. Time line for development and installation of new coal plant designs.

8.6 SUPERCONDUCTORS

Superconductivity is a phenomenon in which certain intermetallic alloys have zero electric resistance when cooled below a certain temperature (the critical temperature of superconducting transition). Since the equipment and associated cost of reaching temperatures near absolute zero is a major limitation in the practical use of this technology, research has been underway to find materials with higher critical temperatures.

> Oxide superconductors discovered in 1986 have the critical temperatures higher than those of conventional superconductors and become superconductive in liquid nitrogen (boiling point 77K). They are called the high-temperature superconductors. Nitrogen exists abundantly in the air and therefore is low cost. The discovery of the materials that become superconductive in liquid nitrogen raised the expectations that superconductivity technology would become practical.[110]

Many firms[111]are engaged in research and development efforts to develop commercially viable applications for superconducting technology including efforts in:

- Underground transmission and distribution cables[112]
- Energy storage[113]—distributed superconducting magnetic energy storage (D-SMES)
- Generators[114]
- Transformers[115]
- Fault current limiters[116]

[110]Sumitomo Industries: http://www.sei.co.jp/super/about_e/index.html.
[111]ABB, GE, Pirelli, Intermagnetics General, Southwire, and Sumitomo Electric.
[112]See Pirelli, Intermagnetics General, Sumitomo Electric, American Superconductor (AMSC) (HTS cable), Nexans (design, manufacturing and design of cable system), Air Liquide (refrigeration system).
[113]See American Superconductor, www.amsc.com/products/transmissiongrid/104273034641.html
[114]Late in 2002, GE Power Systems received $12.3 million in funding from the U.S. Department of Energy to move high-temperature superconducting generator technology toward full commercialization.
[115]ABB was the first company to connect a superconducting transformer to a utility power network in March of 1997.
[116]American Superconductor is working with Consolidated Edison Co. to develop a fault-current-limiting superconductor power system in New York City. The Department of Homeland Security provided a grant for that project, which is expected to be operating by 2010.

In 2008, American Superconductor and the Long Island Power Authority (LIPA) commissioned the grid's first high-temperature superconducting cable. The cable operates at 138 kV and is 2000 feet long. It is reported by the manufacturer that the superconductor power cable is HTS wire that can conduct 150 times the electrical current of copper of the same dimensions and that the cable assembly in a coaxial configuration produces essentially zero electromagnetic field (EMF) emissions. However, for practical transmission purposes, cable "runs" need to be measure in miles not in feet. One of the practical considerations in using superconductors in the power grid is the ability to achieve and maintain the critical temperature in a cost-effective manner over long distances.

CHAPTER 9

RELIABILITY

9.1 CAUSES OF OUTAGES

Interruptions in the supply of electricity to customers can occur at any hour of the day or night and can last from fractions of a second to many hours or even days. Interruptions can be caused by disturbances to or malfunctions of any of the three components of the power system: generation, transmission, or distribution. They can also be caused by the unavailability of adequate resources to supply the customer load. These two attributes of reliability are characterized by NERC as security and adequacy.

Data shows that over 90% of customer outages are caused by problems originating on the local distribution system. Although generation and transmission-related outages are less common than those related to the distribution system, they often have much more serious consequences because of the number of customers affected and the duration of the outage.

Disturbances can be initiated by:

- External events such as:
  - Environmental factors, including wind, rain, lightening, ice, fire, floods, and earthquakes
  - Accidents such as cars hitting poles
  - Sabotage (sadly)
- Internal events such as
  - Insufficient resources
  - Failure of equipment due to electrical or mechanical stresses
  - Operating errors or decisions

Understanding Electric Power Systems. By Jack Casazza and Frank Delea

Lack of resources can be due to:

- Insufficient generation caused by
  - Low load forecasts
  - Shortages of fuel due to supply disruptions or delivery/transportation problems
  - Opposition to the construction of required new generating capacity
  - Failure of equipment due to electrical or mechanical stresses
  - Poor planning
  - Excessive maintenance outages
  - Regulatory actions restricting the operation of power plants
  - Transmission constraints
  - Generation being retired because it is noncompetitive in the new competitive market
- Insufficient transmission or distribution caused by:
  - Low load forecasts
  - Opposition to the construction of required new transmission or distribution lines
  - Failure of equipment due to electrical or mechanical stresses
  - Poor planning
  - Intentional outages required because of other infrastructure work, such as the widening of roads

The duration of the interruption will be affected by the severity of the disturbance, the power system facilities affected, the redundancy or reserve built into the system, and the preparedness of the involved operating entities to respond. Some interruptions are of very short duration because the disturbance is transient and the system self-corrects. Some interruptions, such as those caused by tornadoes or ice storms, damage significant portions of the system, requiring many days to restore service. When there are insufficient generation resources, the outages may be of a controlled and rotating nature. Their duration might be only during peak load hours.

The extent of the interruption will be determined by the initiating disturbances and the facilities affected. For example, cascading outages caused by a fault occurring when a system is operating above a safe level can involve many states, as can a widespread ice storm. Conversely, a distribution pole damaged by a car may affect only a few homes.

An increasingly important aspect of power system reliability is the quality of service or power quality. With the increasing importance of computers and new electronic communication procedures, imperfections in electric service become increasingly important to the customer. Such imperfections include:

- Momentary interruptions
- Voltages outside of acceptable limits
- Voltage dips of very short duration

Protection against power quality imperfections can often be handled by the consumer. Pressure is mounting, however, for the supplier to improve quality. This raises the question of the responsibility for such improvements in a deregulated power industry with separate companies providing distribution, transmission, and power supply services.

9.2 COSTS OF POWER OUTAGES

The costs of electric power outages to U.S. electric customers are generally called "socioeconomic" costs. Attempts have been made to quantify these costs but the estimates vary widely. One source reports that the costs are $26 billion each year and that they have been increasing as the electric power industry is restructured. A 2001 report[117] from the Electric Power Research Institute (EPRI) states that power outages and problems with power quality cost the U.S. economy over $119 billion per year. Costs are due to:

- Loss of life due to accidents (e.g., no street lights)
- Loss of life of the ill and elderly (death rates go up)
- Loss of productivity by industry
- Loss of sales by business
- Loss of wages of labor
- Damage to equipment in industry
- Fires and explosions
- Riots and thefts
- Increased insurance rates

[117]EPRI, The Cost of Power Disturbances for Industrial and Economy Companies, 2001.

9.3 WAYS TO MEASURE RELIABILITY

Reliability of a system is difficult to measure. Perhaps the best way is through evaluation of the consequences of possible consumer interruptions. Investigations have shown that the best measure of reliability is that of consumer reaction.

Five conditions that have been identified impact the value an average consumer puts on an unsupplied megawatt-hour of lost energy:[118]

- The activities affected by the curtailment and, therefore, the time of day and mix of customers
- The number of interruptions
- Availability of advance warning
- Weather conditions and, therefore, the time of year
- The duration of the interruption

Figure 9-1 shows that this reaction increases dramatically as the frequency of outages increase, as the duration of the outage increases, and with the magnitude or extent of the outage. The following function presents a means of evaluating this reaction:[119]

$$R = \text{function of } \{K, F, T, P, t\}$$

where K is an empirical coefficient proportional to the consumer's dependence on electricity, F is the frequency of interruptions, T is equal to duration of the interruptions, P is the amount of load interrupted, and t is the time when the interruption occurs.

Experience has shown that K increases with increasing consumption of electricity per customer, and t is greatest at the time of day, week, or year when people suffer the greatest hardships if service is interrupted. This criterion for reliability evaluation does not consider other curtailments of service, such as voltage or frequency reductions. These "partial" curtailments are not as important to most consumers as a complete interruption but they should also be considered.

A number of indices have been developed, primarily for the distribution system, to provide another measure of reliability:

[118]Cramton and Lein, "Value of Lost Load," University of Maryland paper, February 2000.
[119]J. A. Casazza, Generation and Transmission Reliability, CIGRE Paper #32-11, Paris, France, 1970.

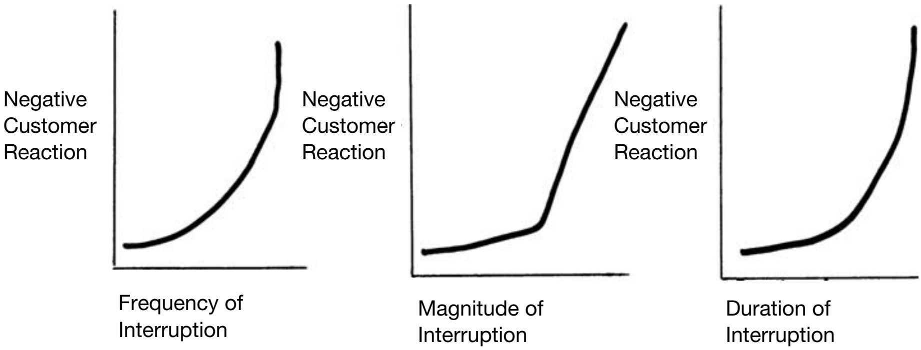


Figure 9-1. NERC regions. Source: NERC.

- SAIFI (System Average Interruption Frequency Index) measures the average frequency of sustained interruptions per customer
- SAIDI (System Average Interruption Duration Index) measures the average time that all customers are interrupted
- CAIDI (Customer Average Interruption Duration Index) represents the average time required to restore service to the average customer per sustained outage
- MAIFI (Momentary Average Interruption Frequency Index) tracks the average frequency of momentary interruptions, typically defined as less than five minutes

9.4 PLANNING AND OPERATING A RELIABLE AND ADEQUATE POWER SYSTEM

The electric utility industry over time developed planning, operating, and design standards to address customer expectations of reliable service. These standards were at first local in perspective but, as interties were built and the interdependent nature of the system became apparent, many of the standards were expanded to a regional and then a national perspective.

A basic question is whether market forces result in an economical and reliable transmission system. In the United States, we have three huge synchronous systems. Each of these synchronous systems behaves as a single machine. This means that outages, generation, transmission changes, and problems in any one area in the synchronous network can affect the entire network. Changes in one location affect not only line loadings and voltages, but also stability limits, short-circuit duties, and required relaying in other systems. Problems in California affect the northwest and Arizona. If a generator is lost in New York City, its affect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans.

Transmission lines cannot be added helter-skelter based solely on the profits for the owner. Locations and designs for new substations selected by the distribution systems must recognize the future of the transmission system that will supply them. One cannot design a reliable low-cost automobile by having separate uncoordinated designs for the brakes, the transmission, the engine, and other essential systems. The same is true for the transmission system. It must be designed as an integrated whole.

Since the effects of electrical disturbances can spread over a wide, multistate region, the need for regional coordination in planning and operation is obvious. As the new market rules for the electric system are developed, the concern is that the rules in any one area do not lower the local reliability standards and thereby impact or impair the reliability of the grid.

Concurrently, over the last century and continuing to the present, customer expectations of reliable service have also increased. Outages which once were commonplace are now considered unacceptable. Momentary interruptions, which at one time were noticed by only a few customers, now impact many customers because of the widespread use of computers and other electronic devices.

Underlying the industry's approach to reliability was the realization that its efforts should be multidimensional:

- Plan the system to have enough generation, transmission, and distribution capacity
- Design the system to reduce the probability of equipment failure
- Operate the system to remain within safe operating margins
- Be prepared to restore the system quickly, in the event of a supply disruption

In all cases, the industry's efforts involve a trade-off between reliability and costs. It would be impossible to build enough facilities or operate with enough of a reserve margin to have a perfectly reliable system. For example, some types of common-mode failures due to causes such as tornadoes, ice storms, or hurricanes involve so many facilities that it would be financially impossible to design a system to tolerate them. This is why the requirement for restoration plans is so important. These plans should encompass a wide range of issues including, but not limited to clear lines of authority for managing the restoration process, staff mobilization plans, plans to rapidly acquire and deliver spare parts to replace damaged equipment, order of restoring generation[120] and transmission facilities, and so on.

The bases for the standards that have been developed are varied. All reflect, in one way or another, a view of an acceptable level of reliability. Generation planning standards have, in the past, been tied to a statistical measure. Standards for operating the generation and transmission systems are based primarily on the collective judgments of utility personnel. Over the years, these standards have been accepted and legitimized by local, state, and national regulators in rate cases and in after-the-fact reviews of outages. In many of these reviews, customer complaints over service reliability and over costs have caused modifications to aspects of individual standards. For example, problems with restoration times in some areas after major storms have led to requirements for detailed and publicized restoration plans reflecting customer inputs.

Attempts have been made to determine and set the level of transmission system reliability based on the reliability of each of the components of the system. Although appealing in theory, this effort flounders on the magnitude and variations in equipment that constitute a power system. The system is designed to reflect good engineering judgment. For example, an engineer can select a number of designs for a new bulk power substation depending on its criticality. The planner could select a substation with a breaker-and-a-half arrangement, which provides more redundancy and, hence, a higher level of reliability than a ring bus design provides.

Information on reliability issues is also obtained from postincident reviews covering major regional disturbances both in the United States and overseas. Since the laws of electricity apply to all transmission grids, lessons learned from overseas blackouts can fruitfully be applied in the United States.

[120]Having generation blackstart capabilities would be included in these plans.

Some specific examples of major blackouts from which lessons have been learned are listed below.[121] This is by no means a comprehensive list but it does illustrate that large-scale blackouts are not uncommon.

- 1965—Northeast United States
- 1967—Mid-Atlantic United States
- 1977—New York City
- 1978—France
- 1987—Tokyo
- 1997—California
- 1997—New Zealand
- 2003—Northeast United States[122]
- 2003—London
- 2003—Denmark/Sweden
- 2003—Italy
- 2004—Greece
- 2005—Australia
- 2005—Moscow
- 2006—Europe
- 2006—Tokyo
- 2007—Victoria, Australia
- 2007—South Africa
- 2007—Colombia
- 2008—Brazil

In some instances, the lessons learned are technical in nature, such as the criticality of voltage support as demonstrated in the blackouts in France in 1978, in Tokyo in 1986, and in the Northeast United States in 2003. In other instances, the lessons are orga-

[121]After-the-fact reviews of blackouts are of varying quality and depth. Some are available on the Internet and some are not. Information on some can only be obtained from newspaper accounts. The comprehensive FPC report on the 1965 Northeast U.S. blackout can be found at http://blackout.gmu.edu/archive/a_1965.html. FERC and N.Y. State reports on the 1977 New York City blackout can be found at http://blackout.gmu.edu/archive/a_1977.html. The extensive report issued by Con Edison on its 1977 blackout is not available online. The authors suggest that if a reader is interested in more information relating to a specific blackout that he/she try a "Google search."

[122]See the U.S.–Canadian Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations—April 2004" at www.ferc.gov/industries/indus-act/blackout.asp. Other reports can be found on the NERC site.

nizational, such as the need for expanded planning and operational coordination after the Northeast U.S./Canada blackout of 1965 and the need for better intra- and interarea communication after the New York City blackout of 1977 and the Northeast/Canada blackout of 2003. Lessons learned from this latter blackout resulted in significant changes in the regulation and oversight of the electric utility industry in the United States.

As the structure of the industry evolves, the trade-offs between reliability and cost will become more difficult in that different companies will be involved in the supply–delivery chain, and each will have a different perspective on the cost–benefit relationship of reliability. Some observers questioned whether the rapid restructuring of the electric power industry in the United States was a root cause of the 2003 Northeast blackout in that the expansion of the wholesale electric market and its many new participants was not adequately coordinated with the systems, equipment, and procedures necessary to operate reliably.

Reliability will depend on whether the "Three Musketeers" or the "Lone Ranger" approach is used. With the Three Musketeers approach, problems of one system or company are shared by all in an effort to minimize total societal costs. In the Lone Ranger approach, each system or business customers suffers alone the consequences of its problems. Some believe this will provide motivation for all to meet their obligations.

One finds in the literature discussions of the customer's willingness to pay for a greater level of reliability. There are two ways to give greater levels of service:

1. Provide more redundancy of supply to one customer than to another
2. In the event of a disturbance or insufficient capacity, disconnect or interrupt the customer who does not pay a premium rate for electricity

Given the reality of how a power system is physically structured, the redundancy option has limited application in protecting specific customers against transmission facility outages, especially when the exposure is to a security violation, that is, loss of a facility. In select circumstances, a larger customer may be able to have a higher level of local distribution service by providing that customer with another distribution feeder or transformer, but extending the option to the typical customer would become cost prohibitive if individual distribution facilities were to be targeted to individual customers. The same logic applies to the transmission grid. Additionally, trying to distinguish between customers at the transmission level during dynamic conditions where instability occurs would be impossible under many conditions.

If the reliability problem is one of adequacy, that is, insufficient resources, when operating personnel have time to take corrective action, customers willing to pay a higher rate could be given preference when adjustments have to be made to restore the load–generation balance. Individual customers also could arrange for their supplier to maintain additional generating reserves for them at added cost. The process of implementing such a plan could rely on either financial mechanisms or physical mechanisms to disconnect customers not opting for higher levels of reliability.

In the past, compliance with national reliability standards has relied on the voluntary cooperation of the companies involved. As discussed in Chapter 10, compliance with reliability standards is now a legal requirement.

Generation

Prior to the restructuring of the industry, generating capacity was traditionally installed to meet a statistically determined reserve requirement, that is, an amount of installed capacity over and above the expected peak load obligation of the supplier. The amount of required reserve was related to a probability of loss of load. The precise determination was tailored to each system and reflected its planning and operating philosophies. The determination usually reflected, for each year, statistics on the reliability of its existing individual generators, the expectation of hourly peak loads, the amount of aid available from nearby systems, intraarea transmission capabilities, and various levels of remedial actions by operators.

In the evolving industry, the question is unanswered of whether the level of installed generation capacity should be a design requirement or should be market determined. NERC removed from its planning criteria a requirement for a targeted installed reserve, relying instead on a market mechanism to set the installed generation reserve level. The National Association of Utility Regulatory Commissioners (NARUC), as part of its National Electric policy, states:

> Congress should mandate compliance with industry-developed reliability standards on the bulk power system that includes *adequate reserve margins* [emphasis added] and preserves the authority of the States to set more rigorous standards when deemed to be in the public interest.

A number of regional entities have implemented a required generation reserve obligation. NERC is revisiting the issue.

Another important consideration in the installed generation picture is the diversity of the fuel supply. Consistent with costs, a diverse fuel generation mix supplies an additional level of reliability. Relying on any one type of fuel, whether hydro, nuclear, coal, oil, solar, or wind can expose the system to common-mode outages. As examples, hydro systems are exposed to the impact of droughts, whereas coal- and oil-fired systems can be impacted by a number of disruptions including worker strikes, disruption in boat deliveries of fuel, and freezing of coal piles in the winter. Solar and wind power can obviously be impacted by weather conditions.

Transmission

Transmission systems must be optimized in three dimensions in order to achieve the necessary reliability and minimum costs for electric power. They should be optimized "geographically," that is, the transmission system must meet the needs of all who are served by the synchronous network, not just the needs or the profits of any one system, any one area, or any one region. Included in geographic optimization, transmission facilities must have a certain degree of physical separation to minimize the potential for common-mode failures. They must be optimized "functionally," that is the transmission system must meet both generation requirements and the requirements of the distribution systems that they supply. These requirements must be balanced on an overall basis. Finally, transmission systems must be developed to meet needs over a significant period of time since they cannot be changed once constructed. Transmission systems must be developed to not only meet needs this year, but well into the future. They must be optimized "chronologically."

Transmission systems are aging and rapidly growing less adequate. The average age for transmission lines, transmission cables, circuit breakers, switch gear, substations, transformers, and other equipment is approaching 30 years, with some key facilities more than 75 years old. Maintenance requires equipment to be taken out of service. Transmission outages on our existing systems can be expected to continue to increase. It is growing increasingly difficult to schedule such outages without taking large reliability risks or incurring large cost penalties due to the inability to deliver low-cost power.

Distribution

Planning and operation of the distribution system is still done according to the standards and practices of individual utilities and reflect local reliability requirements and cost considerations. The robustness of the supply to a congested urban area will be considerably greater than that to a rural farm district. However, oversight of the local utility's performance is usually exercised by state regulatory authorities. It is not uncommon for postincident reviews to be held by regulators after significant local outages. In many areas, the use of incentive rates of return reflecting distribution system performance is becoming popular. Utility equipment design practices reflect standards developed by national organizations such as the Institute of Electrical and Electronics Engineers (IEEE).

9.5 SUMMARY

Future reliability conditions on electric power systems are not subject to exact analyses. Load conditions on electric power systems vary continuously as customer utilization apparatus is switched on and off. As the loads vary and as supply equipment on the system is removed because of the need for maintenance or because of failure, identical conditions will not exist for two of the 8760 hours in a year. While statistics can be accumulated, many other factors must be considered. By far the best individuals or organizations to make estimates of future reliability conditions are those most familiar with these factors. They must be close to what is going on, able to estimate future conditions and judge the sureness of the estimates involved, and to assess the relative risks of alternative courses of action. Reliable determinations are relative and best made by those with great experience.

CHAPTER 10

THE PHYSICAL NETWORK: THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC) AND ITS STANDARDS[123]

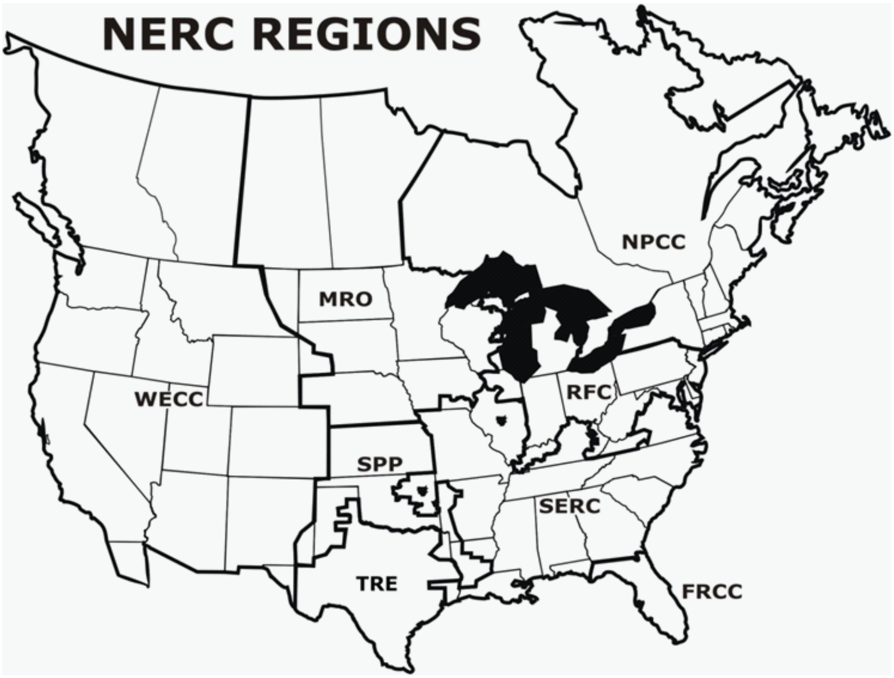
After the Northeast U.S. blackout in 1965, regional electric reliability councils were formed to promote the reliability and efficiency of the interconnected power systems within their geographic areas. These regional councils joined together shortly afterward to form a national umbrella group, NERC,[124] which today is the North American Electricity Reliability Corporation.[125] Presently, there are eight regional reliability organizations. Figure 10-1 shows the name and geographic location of each of these regional organizations. According to NERC,

> The members of these regional organizations come from all segments of the electric industry: investor-owned utilities; federal

[123]The following material was primarily extracted from the NERC website: ww.NERC.com. On this site, all of the planning and operating standards can be accessed.

[124]Originally called the National Electric Reliability Council, the organization was later named the North American Electric Reliability Council to reflect its broader membership across all of North America. After becoming the Electric Reliability Organization, NERC changed its name to the North American Electric Reliability Corporation.

[125]These regional reliability organizations are also referred to as regional entities to which NERC delegates certain of its Electric Reliability Organization authorities.



FRCC—Florida Reliability Coordinating Council
MRO—Midwest Reliability Organization
NPCC—Northeast Power Coordinating Council
RFC—ReliabilityFirst Corporation
SERC—SERC Reliability Corporation
SPP—Southwest Power Pool, RE
TRE—Texas Regional Entity
WECC—Western Electricity Coordinating Council

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.

Figure 10-1. NERC regions (Source, NERC.)

> power marketing agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.[126]

When it was formed in 1968, NERC operated as a voluntary organization to promote bulk electric system reliability and security,

[126]From About NERC, www.NERC.com.

one dependent on reciprocity, peer pressure, and the mutual self-interest of all those involved.

The growth of competition and the structural changes that took place in the industry significantly altered the incentives and responsibilities of industry participants to the point that a system of voluntary compliance was no longer adequate.

10.1 NERC AS ELECTRIC RELIABILITY ORGANIZATION

In 1997, NERC formed the Electric Reliability Panel to independently study and recommend how best to ensure reliability in a restructured and competitive electric utility industry. Concurrently, the U.S. Department of Energy commissioned an Electric System Reliability Task Force (chaired by former Congressman Phil Sharp) with a similar purpose. Both groups came to the same conclusion: that voluntary compliance with reliability standards would no longer work and that federal legislation was needed in the United States to provide for the creation of a self-regulatory reliability organization. NERC drafted legislative language, which its board approved in early 1999. Although the reliability language was well supported in both the House and Senate, it did not move forward as stand-alone legislation, even after the 2003 blackout. It was not until consensus was reached on other provisions of comprehensive energy legislation that NERC's consensus reliability language became law in August 2005.

On February 3, 2006, the Federal Energy Regulatory Commission (FERC) issued Order No. 672 establishing the procedures for the formation and functions of the Electric Reliability Organization (ERO) and Regional Entities and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability. There have been subsequent orders clarifying and amending some conditions of the initial order.[127]

NERC applied for and was granted the role of ERO by FERC in July 2006. It was set up as a self-regulatory organization, subject to oversight by FERC and governmental authorities in Canada. NERC's status as a self-regulatory organization means that it is a

[127]A source of documents on Order 672 can be found at http://www.balch.com/erl/blog.aspx?entry=34; FERC's summary of Order 672 can be found at: http://www.ferc.gov/industries/electric/indus-act/reliability/E-1-overview.pdf.

nongovernment organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.[128]

In April 2007, FERC approved eight regional delegation agreements to provide for development of new or modified standards and enforcement of approved standards by regional entities. Refer to Figure 10-1 for the location of the regional entities.

In its Initial Order FERC indicated that:

- Reliability standards would apply to all users, owners, and operators of the bulk-power system.
- FERC would have the authority to approve all ERO actions, to order the ERO to carry out its responsibilities under these new statutory provisions, and also may independently enforce reliability standards.
- The ERO may delegate its enforcement authorities to a regional entity.
- A regional entity may also propose a reliability standard to the ERO for submission to the FERC for approval. This reliability standard may be either for application to the entire interconnected bulk-power system or for application only within its own region.
- The ERO or a regional entity must monitor compliance with the Reliability Standards. It may direct a user, owner, or operator of the bulk-power system that violates a reliability standard to comply with the reliability standard. The ERO or regional entity may impose a penalty on a user, owner, or operator for violating a reliability standard, subject to review by, and appeal to, the Commission.

The first set of enforceable standards was filed with FERC on April 4, 2006. FERC in Order 693[129] in March 2007 approved 83 of 107 Reliability Standards proposed by NERC, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards. However, FERC noted that "significant improvements" were needed in 56 of the 83. FERC required additional information on the 24 Standards not approved:

[128]NERC website: http://www.nerc.com/page.php?cid=1.
[129]http://www.ferc.gov/whats-new/comm-meet/2007/031507/E-13.pdf.

> As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. Reliability standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.

In July 2008 in Order 713,[130] FERC modified five of the reliability standards, approved in 2007, related to interchange scheduling and coordination. This was the first time FERC acted to modify and strengthen reliability standards first approved in Order No. 693.[131]

The efforts involved to implement the mandatory standard regime of necessity came at a price: a greatly increased level of oversight and the need to increase staffing levels at NERC, at the regional entities, and at the various RTOs, ISOs, and other involved organizations.

10.2 NERC STANDARDS

Functional Model

As the restructuring of the industry was occurring in the 1990s, NERC undertook a process wherein it expanded and clarified its standards for planning and operating the bulk power system and the rules and procedures by which it would conduct its business. As part of this process, NERC recognized that as the industry's structure changed an increasing number and variety of organizations became responsible for various aspects of reliability. To address the new industry structure, NERC developed a Functional Reliability Model[132] that identified the functions needed to ensure

[130] http://www.ferc.gov/whats-new/comm-meet/2007/031507/E-13.pdf.

[131] NERC's standards are continually under review and, as necessary, expansion or modification. The present status of work on all standards can be found at http://www.nerc.com/filez/standards/Reliability_Standards_Under_Development.html.

[132] The Functional Model can be found at http://www.nerc.com/page.php?cid=2|247|108.

the reliability of the bulk electric system and the entities responsible for performing the tasks within each function. Version 1 of the model was approved in 2002; there have been three revisions to date.

The following entities and roles are identified in Version 4 of the Functional Model.

1. Reliability Coordinator

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide area takes precedence over reliability of any single local area. In the next chapter, Figure 11-1 identifies the various Reliability Coordinators.

2. Planning Coordinator

The Planning Coordinator ensures that a long-term (generally one year and beyond) plan is available for adequate resources and transmission within its Planning Coordinator Area.

3. Balancing Authority[133]

The Balancing Authority operates within a predefined part of the electric grid whose boundaries are metered. Each balancing area is unique and in the aggregate cover the entire grid. Every generator, transmission facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation. The load resource balance is measured by the Balancing Authority's area control error (ACE), which is discussed in the next chapter.

Maintaining resource–demand balance within the Balancing Authority Area requires four types of resource management, all of which are the Balancing Authority's responsibility:

- Frequency control through tie-line bias
- Reliability-related services deployment

[133]As of June 22, 2009, there were 133 Balancing Authorities, 21 Reliability Coordinators, and 319 Transmission Operators. The registry for each of the roles can be found at: www.nerc.com/page.php?cid=3\25.

- Load following through generator dispatch and demand-side management
- Interchange implementation

4. Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of loads (customer demand and energy requirements) within a Planning Coordinator Area.

5. Transmission Operator

The Transmission Operator operates or directs the operation of transmission facilities and is responsible for maintaining local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the transmission system within its purview in a manner that maintains proper voltage profiles and system operating limits, and honors transmission equipment limits established by the Transmission Owner.

The Transmission Operator is under the Reliability Coordinator's direction, respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an energy emergency, and can take action in system restoration.

6. Interchange Authority

The Interchange Authority provides the Balancing Authority with the individual bilateral interchange schedules.

7. Transmission Planner

The Transmission Planner develops plans for transmission service and interconnection requests beyond one year.

8. Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In most cases, the organization serving as Transmission Service Provider is also the tariff or market rules administrator.

9. Transmission Owner

The Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

10. Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers and the electric system. For those end-use customers that are served at transmission voltages, either the Transmission Owner or the Transmission Operator also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider and not directly connected to the bulk power system

The Distribution Provider is responsible for local safety and reliability. The Distribution Provider provides the switches and reclosers necessary for emergency action.

11. Generator Operator

The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operations Function. The Generator Operator operates or directs the operation of generation facilities. The Generator Operator is responsible for supporting the needs of the bulk power system up to the limits of the generating facilities in his purview. Ultimately, the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.

12. Generator Owner

The Generator Owner owns its generation facilities and provides for the maintenance of those facilities. It also is responsible for providing verified equipment operating limits and for supplying this information to the Generator Operator, Reliability Coordinator, Transmission Planner, and Planning Coordinator.

13. Purchasing–Selling Entity

The Purchasing–Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy, and reliability-related services) that it secures from a resource for delivery to a Load-Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.

14. Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy to its end-use customers, but does not include distribution services ("wires"). The LSE defined in the model is not to be confused with or equated to the LSE as defined in any tariff or market rule.

Today, organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide or have contracts with other Generator Owners for capacity and energy to serve the LSE's customers, or purchase capacity and energy from nonaffiliated Generator Owners through a Purchasing–Selling Entity (or Market Operator), or employ a combination of these three options.

15. Reliability Assurer[134]

The Reliability Assurer provides an independent assessment of tasks performed by other responsible entities, or facilitates or coordinates such tasks. While the specific role of the Reliability Assurer is not fully developed at the present time (fall 2008), the following are representative of the Tasks that might be performed:

- Perform high-level evaluations, such as at a regional or interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of transmission planners.
- Perform readiness evaluations of responsible entities, to provide assurance that a responsible entity will be able to meet assigned requirements in reliability standards.
- Develop regional reliability plans to ensure there are no reliability gaps or no missing or ambiguous responsibilities or relationships.
- Perform high-level evaluations, such as at a regional or interconnection level, of protection systems as they relate to the reliability of the bulk power system.
- Perform disturbance analysis evaluations.

[134]New to Version 4 of the Functional Model.

The selection of particular tasks for the Reliability Assurer will reflect NERC's judgment on which tasks merit such a "defense-in-depth" approach.

10.3 DEVELOPMENT OF STANDARDS

Each regional reliability organization had some form of planning and operating criteria from the time they were each formed. In addition, an operating organization called the North American Power System Interconnection Committee (NAPSIC), which came into existence in 1962, maintained a list of Operating Guides. When NERC merged with NAPSIC in 1980, the NERC board adopted the NAPSIC Operating Guides as NERC Operating Guides. Over time, these guides became NERC's Operating Policies, Criteria, and Guides, and eventually were converted into Version 0 Reliability Standards. On the planning side, NERC began to synthesize the various regional council planning criteria into NERC-level planning policies. Then, in September 1997, the NERC board adopted the first ever set of NERC Planning Standards. These evolved over time and were also converted into Version 0 Reliability Standards.

Over time, the topics covered by these standards were increased. Following the Northeast blackout of 2003, responding to recommendations in the subsequent report by the U.S. and Canadian governments and as part of the process for establishing itself as the ERO, NERC undertook a systematic approach to expanding and clarifying its standards for planning and operating the bulk power system and the rules and procedures by which it will conduct its business. As part of this process, it incorporated the structure developed as part of the Functional Model. In April 2005, NERC adopted the "Version 0" reliability standards that translated the NERC operating policies, planning standards, and compliance requirements into a comprehensive set of measurable standards:[135]

> NERC reliability standards define the reliability requirements for planning and operating the North American bulk power

[135]Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards (September 1, 2005).

> system. NERC's . . . standards development process is guided by reliability and market interface principles. The Reliability Functional Model defines the functions that need to be performed to ensure the bulk electric system operates reliably, and is the foundation upon which the reliability standards are based.

Reliability Principles

The reliability principles are:

1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained, and implemented.
5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk electric systems
6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
7. The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

Market Interface Principles

NERC states that

> Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all reliability standards shall be consistent with the market interface principles. Consideration of the market interface principles is

intended to ensure that reliability standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

The market interface principles are:

1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy.
2. An Organization Standard shall not give any market participant an unfair competitive advantage.
3. An Organization Standard shall neither mandate nor prohibit any specific market structure.
4. An Organization Standard shall not preclude market solutions to achieving compliance with that standard.
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially nonsensitive information that is required for compliance with reliability standards.

Presently, the Standards are grouped into the 14 categories shown in Table 10-1. Within each category there are individual standards. For example, Table 10-2 shows the standards within the Resource and Demand Balancing category.

Table 10-1. NERC reliability standard categories

Resource and Demand Balancing	BAL
Critical Infrastructure Protection	CIP
Communications	COM
Emergency Preparedness and Operations	EOP
Facilities Design, Connections, and Maintenance	FAC
Interchange Scheduling and Coordination	INT
Interconnection Reliability Operations and Coordination	IRO
Modeling, Data, and Analysis	MOD
Nuclear	NUC
Personnel Performance, Training, and Qualifications	PER
Protection and Control	PRC
Transmission Planning	TPL
Transmission Operations	TOP
Voltage and Reactive	VAR

Table 10-2. Resource and demand balancing standards

BAL-001-0a	Real Power Balancing Control Performance
BAL-002-0	Disturbance Control Performance
BAL-003-0	Frequency Response and Bias
BAL-004-0	Time Error Correction
BAL-005-0b	Automatic Generation Control
BAL-006-1	Inadvertent Interchange
BAL-STD-002-0	Operating Reserves—A Regional Reliability Standard for the Western Interconnection

Compliance with NERC Standards

All bulk power system owners, operators, and users must comply with approved NERC reliability standards. These entities are required to register with NERC through the appropriate regional entity. NERC relies on the regional entities to enforce the NERC standards with bulk power system owners, operators, and users through approved delegation agreements. Regional entities are responsible for monitoring compliance of the registered entities within their regional boundaries, assuring mitigation of all violations of approved reliability standards and assessing penalties and sanctions for failure to comply. Regional hearing processes are available to resolve contested violations or penalties or sanctions.

Other NERC Responsibilities

Other NERC responsibilities are:

- Working through the Regional Entities, ensure compliance with and enforcement of the standards, including directives for any required remedial actions to remove violations.[136] NERC relies on the regional entities to enforce the NERC standards.
- Annual reliability and adequacy assessments, including issues related to power generation, transmission, fuel delivery, fuel supply, and demand-side measures. Nonsystem factors that could impact reliability and adequacy, such as the ramifications of an aging workforce and environmental legislation, are also considered.

[136]Sanctioning of confirmed violations is determined pursuant to the NERC Sanction Guidelines and is based heavily upon the violation risk factors and violation severity levels of the standard violated and the violation's duration.

- Events analysis, including the identification and dissemination of "lessons learned" from industry incidents
- Coordinate efforts to protect the industry's critical infrastructure from physical and cyber threats. Security is addressed in the daily operation of the electricity grid and in future planning of the grid[137]
- Certification of System Operators

The Future

NERC continues to evolve. Its goals for 2008 were outlined by CEO Rick Sergel and included the following:

1. Improvement in the Electric Sector Information Sharing and Analysis Center (ESISAC), which will increase coordination with Canadian and U.S. officials on cyber security.
2. Recommend a metrics implementation plan resulting in at least ten bulk power system leading indicators.
3. Encourage and promote the adoption of synchro-phasor technology in the United States and in Canada to improve the accuracy of wide-area measurement.

[137]NERC operates the industry's Electricity Sector Information Sharing and Analysis Center (ESISAC) under the U.S. Department of Homeland Security and Public Safety Canada. ESISAC gathers information about security-related threats and incidents, and communicates it to government authorities.

CHAPTER 11

THE PHYSICAL NETWORK: OPERATION OF THE ELECTRIC BULK POWER SYSTEM

The operation of a power system involves two primary functions: managing the market for electricity and managing the physical performance of the devices used to generate and deliver the electricity to customers. Requirements for the reliable operation of the physical performance of the system are defined by NERC's standards. Rules to ensure an open nondiscriminatory market are in the tariffs approved by FERC and available on the various Open Access Same-Time Information System (OASIS) sites.

With the implementation by NERC of its Functional Model, there are a number of entities assigned responsibility for various aspects of the physical operation of the power system. The three primary entities are the Balancing Authority,[138] the Reliability Coordinator, and the Transmission Operator.

11.1 BALANCING AUTHORITIES

Table 11-1 shows the number of Balancing Authorities on a Regional Reliability Council basis. The Balancing Authority Areas vary greatly in both geographic size and the amount of generation/load they control. Since the early 2000s, the number of Balancing Authorities has decreased from over 140 to 133. As can be seen in the table, some regions have many more Balancing Authorities than others. Some observers feel that too many Balancing

[138]Historically this entity had been called a Control Area.

Understanding Electric Power Systems. By Jack Casazza and Frank Delea

Table 11-1. Balancing authorities by NERC region

Area	Number of BAs
ERCOT	1
FRCC	11
MRO	19
NPCC	5
RFC	13
SERC	30
SPP	17
WECC-AZNMSNV	11
WECC-CAMX	5
WECC-NWPP	17
WECC-RMPA	2

Authorities can result in a more complicated and potentially less reliable system.

The overriding objective of those individuals responsible for the performance of the electric system is to ensure that at every moment of time there is sufficient generation to reliably supply the customer requirements and all associated delivery system losses. The process is complicated by the fact that the customer load changes continuously and, therefore, the generation must adjust immediately, either up or down, to accommodate the load change. Since electric power cannot be stored, the generation change must be accomplished by a physical adjustment of the equipment generating the electricity.

Area Control

Each Balancing Authority is responsible for maintaining its own load/generation balance, including its scheduled interchange, either purchases or sales. A Balancing Authority can consist of a generator or group of generators, an individual company, or a portion of a company or a group of companies, providing that it meets certain certification criteria specified by NERC. It may be a specific geographic area with set boundaries or it may be scattered generation and load.

Since minute-by-minute customer load changes are not known in advance, a system has been developed whereby generation changes are made in response to load changes. This system is based on the concept of the area control error. The sum of the internal generation within a Balancing Area and the net flow on its interties is equal to the customer load and all transmission losses within the area. The net power flow into/out of the area should be equal to the net of all transactions between parties in the area and parties outside the area. To determine the net schedule transactions, the various commercial interests that are within the area are required to notify the Balancing Authority personnel (via the Interchange Coordinator) of their bilateral contractual arrangements on an ongoing basis for either sales or purchases of electricity with entities outside the area's boundaries. Additionally, neighboring operating entities engaged in transactions that will cause power to flow through the Balancing Area are required to notify the Balancing Authority (through the Interchange Authority) and to make provision for the attendant transmission losses.

With this information, the Balancing Authorities can compare the total scheduled interchange into or out of the control area with the actual interchange. If the flow into the area exceeds the schedule for that time period, internal generation must be increased. Conversely, if the net flow is below the schedule, generation within the area must be reduced. Operationally, this is an ongoing process conducted every few seconds. Since these adjustments are going on simultaneously in all balancing areas, the adjustments balance out.

Each Balancing Authority also participates in maintaining the average system frequency at 60 hertz. The system frequency can deviate from normal when a large generating unit or block of load is lost.[139] In addition to adjustments made because of variations of tie flows from schedule, another adjustment is made to correct frequency deviations.[140] Each Balancing Authority is required to have an adjustment factor related to frequency in its control logic. The term is called the *tie-line frequency bias* (expressed in mW/0.1 Hz).

Additionally, since the control process is responsive, there can be a drift in average system frequency, which, in turn, affects the accuracy of any electric clocks. This variation is monitored and for a period of time the target frequency reference is adjusted to produce the required compensation. This process is called time error correction.

[139]Generators larger than 10 mW within each control area should be equipped with speed governors that will respond to frequency (i.e., speed) excursions.
[140]This is called automatic generation control (AGC).

Operating Reserves

Each Balancing Authority must provide operating reserves to restore its tie flows to schedule within 15 minutes following the loss of a generator within the area. Operating reserves consist of spinning and nonspinning reserves. Spinning reserve is generation that is synchronized and available to supply incremental load in a specified time period. Nonspinning reserve is not synchronized but can be made available within a short period of time. Interruptible load disconnection and coordinated adjustments to interchange schedules can be considered as part of operating reserve. NERC's standards defer to the Regional Councils as to the mix of these reserves [whether they be spinning or supplemental (offline but available within the 15 minute period)].

With the restructuring of the industry; the emergence of merchant power plant owners; the development of ISOs, RTOs, and for-profit transmission companies; and the implementation of retail access in some regulatory jurisdictions, assigning all reliability responsibilities to balancing authorities made the job of defining and applying standards more and more complicated. This was further complicated since some balancing areas are acting as transmission service providers.

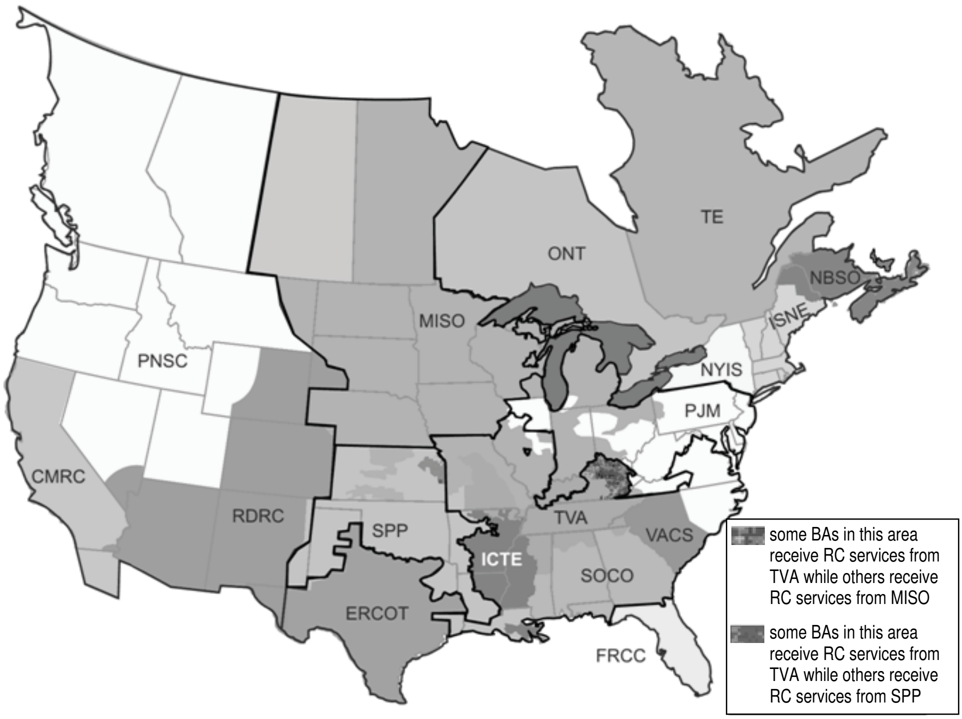
The ongoing adjustments to generation levels within each balancing area are, of course, done by computer-based control systems that send signals to generators that provide needed adjustments (i.e., regulation), either up or down.

11.2 RELIABILITY COORDINATORS

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide area takes precedence over reliability of any single local area.

The Reliability Coordinator directs the Transmission Operator with respect to wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an energy emergency, and can take action in system restoration.

Figure 11-1 identifies the Reliability Coordinator Areas in



ERCOT	ERCOT ISO
FRCC	Florida Power & Light
TE	Hydro Quebec, TransEnergie
ICTE	Independent Coordinator Transmission—Entergy
ISNE	ISO New England Inc.
MISO	Midwest ISO (2 locations)
NBSO	New Brunswick System Operator
NYIS	New York Independent System Operator
ONT	Ontario—Independent Electricity System Operator
WECC1*	Western Electricity Coordinating Council RC
PJM	PJM Interconnection
SPRC	Saskatchewan Power RC
SOCO	Southern Company Services, Inc.
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
VACS	VACAR-South

*WECC recently combined the three Reliability Areas (CMRC, PNSC and RDRC) into a single area for the entire Western Interconnection.

Figure 11-1. Reliability coordinator areas.

the United States and Canada. There is no single organizational structure for a Reliability Coordinator, although a number are ISOs.

11.3 TRANSMISSION OPERATORS

Each Transmission Operator is responsible for ensuring that the bulk power system is operated to meet a consistent set of standards and procedures. As noted in Chapter 10, NERC has established standards covering planning and operations to ensure electric system reliability. The specific details have been codified by each of the eight regional Reliability Councils and are in the process of being approved by FERC. In addition, as noted earlier, Regional Entities may implement more stringent criteria, standards, and procedures if their situation warrants.

The Transmission Operators evaluate the expected power flows internal to the balancing area to determine if adjustments are required in the generation pattern to ensure that all transmission facilities are operated within their capabilities.

Each Transmission Operator and Generator Operator must ensure that all available reactive resources within its boundaries are utilized to maintain adequate voltage levels under normal and contingency conditions.

Power Transfer Limits

A primary aspect of a Reliability Coordinator's and a Transmission Operator's responsibilities toward the reliability of the bulk power system is to make certain that the levels of power transfers that take place within and between Balancing Authority areas are within the capability of the bulk power transmission system reflecting that area's operating standards.

In order to define the amount of transmission capacity available for commercial transactions, NERC[141] developed the following definitions:

[141]"Available Transfer Capability Definitions and Determination," NERC, June 1996.

Available Transfer Capability (ATC) = Total Transfer Capability (TTC)
– Existing Commitments
– Transmission Reliability Margin (TRM)
– Capacity Benefit Margin (CBM)

where:

- Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.[142]
- Total Transfer Capability (TTC) is the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and postcontingency system conditions.
- Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
- Capacity Benefit Margin (CBM) is that amount of transmission transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation requirements in emergencies.

Determination of Total Transfer Capability

The total transfer capability is the acceptable magnitude of power flow in one direction over a group of transmission lines often referred to as an interface or the flowgate. A Balancing Authority area may have many of these interfaces, both internal to the area and at its points of connection with adjoining areas. The transmission lines comprising an interface are not necessarily at the same voltage or between the same substations.

The capability is determined by examining the performance of the transmission system under normal conditions and during and after a variety of contingencies to ensure that voltages are within an acceptable range, that the system is stable and that power flows on all lines are within acceptable ratings.

[142]See FERC Order 890, which addresses consistency in calculation of ATC.

The total transfer capability is set by the power flow level at the most limiting constraint. It can be:

- Predisturbance related—Unacceptable line loadings or bus voltages
- Disturbance related—Transient, voltage, or dynamic instability
- Postdisturbance related—Unacceptable line loadings or bus voltages

For a stability limit or a voltage limit, none of the transmission lines on the interface may be loaded to their individual capacity. For a situation in which the loading on an individual line sets the limit, the loadings on all other parallel lines are most probably below (perhaps well below) their capacities. It is these latter situations that are the reason for interest in the use of phase-shifting transformers and in the development of FACTS devices that would allow the system to transmit more power using existing facilities. These devices can change the apparent electrical characteristics of a transmission line, causing a redistribution of the power flows across a group of transmission lines.

The contingencies to be considered when determining the total transfer capabilities are detailed in NERC and individual reliability council standards. As a minimum, the bulk power system is to be operated to what is called the N-1 criteria. NERC states, "All Balancing Areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

Parallel Path Flow and Loop Flow

Parallel power flows reflect the interconnected nature of the bulk power system that we have mentioned previously. Since power flows on all transmission paths, it is not uncommon to find circumstances in which part of a power delivery within one balancing area flows on transmission lines in adjoining areas, or part of a power delivery between two balancing areas flows over the transmission facilities of a third area. In addition, loop flows also occur and are the result of generation location and transmission system design and reflect the situation in which all systems are supplying their own load from their own resources but some of the power flows on the transmission in other systems. These circumstances have been referred to as a seams issue.

Reduction of Power Transfers—Congestion Management

Congestion is a term that is applied to situations in which the amount of power flowing or projected to flow across a group of transmission lines (a flowgate or interface) exceeds the capacity of those lines. To relieve the potential overload, the electrical operation of the system must be adjusted in one of two ways:

1. Reducing power flows by reducing generation in the sending system and increasing generation or reducing load in the receiving system
2. Changing the system configuration by opening lines or by closing or segmenting buses

This process is covered by NERC's Transmission Loading Relief Procedure.

With the ongoing efforts to open the electricity systems for market-based wholesale transactions, complications arise when attempting to redispatch the system generation to eliminate or avoid power transfer limit violations; specifically, how should economics be factored into the adjustments? One complication is that the generating units that might have the most direct effect on reducing the transfer limit violation might be lower in cost than other units further removed from the violation. A further complication occurs when the various generators that could relieve the violation are in areas using different market rules.

Congestion limits are essentially economic limits concerned with operation of the power market. The location of these limits is not always the same as the location of the actual reliability risks in the transmission system.

Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

Ancillary Services

FERC in its Order 888[143] also specified ancillary services needed to facilitate the operation of a bulk supply system.[144] They are:

[143]See Chapter 14 for a discussion of this order.
[144]Responsibility for these services is assigned to the various entities in the NERC Functional Model.

Scheduling, system control, and dispatch. Scheduling is the before-the-fact assignment of generation and transmission resources to meet forecasted loads. Dispatch is the real-time control of all generation and transmission resources that are currently online and available to supply load and to maintain reliability within the balancing area.

Reactive supply and voltage control from generators. Services necessary to maintain system voltages within acceptable limits provided by generation resources that are capable of producing (or absorbing) reactive power and by other types of electrical equipment.

Regulation. Automatic generation control (AGC) is a system that continuously compares, for the area of each Balancing Authority, total net actual power interchange to total net scheduled power interchange. It also determines if the area is required to adjust its generation to assist in the maintenance of system frequency.[145] The combination of variation from scheduled interchange and the variation of frequency multiplied by the area's tie-line bias setting determines an area control error (ACE). The AGC system sends signals to generation units in the area to either increase or decrease output to reduce area control errors (ACE) to zero.

Operating reserves consisting of contingency reserves and regulating reserves

- **Contingency reserves** are spinning reserves[146] immediately responsive to automatic generation control (AGC) and supplemental reserves consisting of additional spinning reserve and nonspinning reserve (at least half of which must be spinning reserve) provided by resources available to the transmission provider to use in the event of a system contingency.
- **Regulating reserves** are provided through the capacity of frequency-responsive generation resources or certain demand-response resources held in reserve for the purpose of provid-

[145]Each area is assigned a value representing its share of the responsibility to maintain adequate system frequency (its frequency bias).

[146]Generation synchronized to the system (i.e., online) but not fully loaded and fully available to serve load at the time of the contingency event or load removable from the system at the time of a contingency event.

ing regulating reserve deployment in both the up and down directions.

Load following (also energy imbalance) service is the provision of generation (and load) response capability to match differences between actual and scheduled transactions.[147]

Backup supply. Real power loss replacement to cover the difference between generated real power and the real power delivered to customers.

Dynamic scheduling. Defined by NERC as a "telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area."

System black start capability is the ability to start a generator or a system in the event of a blackout without reliance on other systems. These units can be used to provide start-up power to other units to allow restoration of the area experiencing a blackout.

Network stability services are the use of fast response equipment to maintain a stable system.

11.4 VOLTAGE AND REACTIVE CONTROL[148]

Since adequate bulk power system voltage is critical, NERC standards require:

1. Monitoring and controlling voltage and mVAr flows within its boundaries and with neighboring control areas.
2. Providing reactive resources within its boundaries to protect the voltage levels under contingency conditions, including its share of the reactive requirements of interconnecting transmission circuits.

[147]This service is required since scheduled transactions are based on forecast customer requirements which, almost by definition, will be somewhat different from actual requirements.

[148]As noted in Chapter 9, voltage problems have caused or contributed to a number of major system blackouts.

3. Operating capacitive and inductive reactive resources to maintain system and interconnection voltages within established limits.
4. Operator information. The system operator shall be provided information on all available generation and transmission reactive power resources, including the status of voltage regulators and power system stabilizers.
5. Preventing Voltage Collapse. The system operator shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.
6. Voltage and Reactive Devices. Devices used to regulate transmission voltage and reactive flow shall be available under the direction of the system operator.

11.5 EMERGENCIES

There are two philosophies concerning operating a power system and dealing with emergencies, as follows.

Preventative Philosophy. The approach that has predominated in the United States for many years is preventative operation. If a transmission operator discovers a condition in which a single contingency will cause an overload and possible trip-out of another facility, a low-voltage condition, or instability, he will adjust the operation of his system to reduce the loading conditions and eliminate this potential hazard. With this philosophy, power transfers, interchanges, and economic dispatches that could be economically beneficial are often not made. This is the philosophy required by NERC.

Corrective Philosophy. There is an increasing amount of attention being given to the impact of taking larger risks in the operation of transmission systems because of the significant savings that might be made. The corrective philosophy states that you do not reduce the transfers until after the contingency has occurred. This means that for the high percentage of times that the contingency does not occur, the economic benefits will accrue. However, it also means that for the small percentage of the time when the contingency does occur, severe reliability penalties could result through a major disruption of the power supply.

To implement a corrective approach, both the capacity and reliability of transmission networks will have to be improved through the development and installation of highly automated, "smart" power system technology.[149,150] The grid will need technological advances in four major areas:

1. Improved physical control to expedite grid operations by switching power more quickly and preventing the propagation of disturbances
2. Monitoring systems that can improve reliability by surveying network conditions over a wide area
3. Analytical capability to interpret the data provided by the wide-area monitoring system for use in network control
4. A hierarchical control scheme that will integrate all of the above technologies and facilitate flexible network operations on a continental scale

Electric systems are now adding these technologies to their transmission systems, creating smart networks. The possible future of these "smart" control schemes will have to be carefully analyzed (see Chapter 8).

Operating Emergencies[151]

NERC requires each Transmission Operator to have a set of plans to mitigate operating emergencies. These plans must be coordinated with other Transmission Operators and Balancing Authorities and the Reliability Coordinator. They must contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

Each Transmission Operator and Balancing Authority must develop, maintain, and implement a set of plans to mitigate operating emergencies for:

- Insufficient generating capacity
- Operating emergencies on the transmission system
- Load shedding
- System restoration

[149]K. Stahlkoph and P.R. Sharp, *Where Technology and Politics Meet—Electric Power Transmission Under Deregulation,* IEEE Press, 2000.
[150]See Chapter 8 for additional information about the Smart Grid concept.
[151]See NERC Standard EOP-001-0—Emergency Operations Planning at http://www.nerc.com/page.php?cid=2|20.

The emergency plans need to include:

- Communications protocols
- A list of controlling actions to resolve the emergency, including load reduction
- The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities
- Staffing levels for the emergency

Items to be considered include fuel supply and inventory; fuel switching at generators where possible; environmental constraints, reduction of in-system energy use; public appeals, implementation of load management and voltage reductions;[152] appeals to large customers to reduce usage, running generators at maximum output; requests for governmental aid to implement energy reductions; and mandatory involuntary load curtailment.

In the event that the above actions are insufficient or if the situation develops too rapidly to implement them, each area is required to install underfrequency load shedding. This is a system in which protective relays detect a low-frequency condition and actuate the disconnection of blocks of load in an attempt to arrest the decline in frequency and restore 60 Hz operation before the low frequency results in the loss of additional generation.

11.6 INFORMATION EXCHANGE

A critical aspect of maintaining reliability and ensuring an open and competitive market is to ensure that all parties share pertinent information about the status of the electric system. Data availability is of two types: that as defined by FERC as needed for commercial scheduling purposes and required to be made available on OASIS sites, and that needed for operational and planning purposes as identified in NERC standards and to be shared by various entities.

Timely sharing of correct operational information was identified as critical to reliability in numerous postblackout reviews. The following are the types of data that Reliability Coordinators,

[152]The effects and duration of load reductions depend on the characteristics of the load.

Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.[153]

- The following are to be updated within ten minutes:
  - Transmission data for all interconnections plus all other facilities considered to be key from a reliability standpoint
  - Generator data
  - Operating reserve
  - Balancing Authority demand
  - Interchange
  - Area control error and frequency
- Other operating information to be updated as soon as available:
  - Interconnection reliability operating limits and system operating limits in effect
  - Forecast of operating reserve at peak, and time of peak for current day and next day.
  - Forecast peak demand for current day and next day
  - Forecast changes in equipment status
  - New facilities in place
  - New or degraded special protection systems
  - Emergency operating procedures in effect
  - Severe weather, fire, or earthquake
  - Multisite sabotage[154]

Reporting requirements impacting contractual arrangements have been formalized by FERC in its Orders 888 and 889,[155] issued in 1996 and further expanded in Order 890, issued in 2007. Order 889 stated, in part, that "A public utility . . . must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power."

The information that is reported includes:

- Available transmission capacity
- Transmission service products and prices
- Ancillary service offerings and prices
- Transmission service requests and responses
- Curtailments and interruptions

[153]Source, NERC standards.
[154]NERC Standard 005-1
[155]http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt.

- Denials of requests for service
- Facility status information

The reports are entered into the Open Access Same-Time Information System (OASIS), an Internet-based bulletin board which gives energy marketers, utilities, and other wholesale energy customers real-time access to information regarding the availability of transmission line capability. OASIS provides the ability to schedule firm and nonfirm transactions.

In Order 890, additional information was mandated for inclusion in OASIS:

- All business rules, practices and standards that relate to transmission services provided under their Open Access Transmission Tariffs (OATTs),[156] and to include their credit review procedures in their OATTs.

The Commission requires transmission providers and their network customers to use the transmission provider's OASIS to request designation of a new network resource and to terminate the designation of an existing network resource.

The process by which individual contracts scheduled within OASIS are identified as to source and customer is known as tagging. This information, though it may be commercially sensitive, is critical if system operators are to adjust system power flows to maintain reliable levels

[156]Required to be filed with and approved by FERC.

CHAPTER 12

THE PHYSICAL NETWORK: PLANNING OF THE ELECTRIC BULK POWER SYSTEM

Prior to the restructuring of the industry and the opening of the transmission system to many different users, the planning process was reasonably straightforward. The process integrated load forecasting, generation planning, and transmission planning, and was usually done by one entity, either a company or a power pool. Coordination of plans was done under the auspices of the Regional Councils.

The process normally started with a peak load forecast. In most cases, the forecast projected growth in peak loads.[157] The planning objectives were:

- Generation—to have enough generation capacity to meet the projected peak load and system losses plus a reserve margin
- Transmission—to connect generators to the grid, to have enough transmission capability to reliably deliver generation and firm purchases to existing and new load centers, to accommodate the sharing of reserves with nearby areas, and to allow economically driven power exchanges both intraarea and interarea
- To provide these services over an extended period of time at minimum cost.

[157]Many utilities experienced financial difficulties during the 1970s and 1980s when forecast peak loads did not materialize, while, at the same time, costly, large generating units were under construction.

Understanding Electric Power Systems. By Jack Casazza and Frank Delea

In both cases, the financial return on and of the resulting facilities was regulated and based on a cost-of-service perspective.

Regional Councils had agreed upon criteria covering:

- Generation reliability expressed in terms of a target reserve or minimum acceptable loss of load probability
- Transmission reliability expressed in terms of a number of disturbances that the transmission system had to be able to withstand while meeting the above-stated objectives

12.1 PLANNING STANDARDS

NERC's planning standards[158] define the reliability aspect of the interconnected bulk electric systems in two dimensions:

1. Adequacy—the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements
2. Security—the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements

To these we should add safety for workers and the general public, and, especially since September 11th, an expanded focus on physical and cyber security.

12.2 GENERATION PLANNING

Historically, to meet the adequacy standard, generation reserve margin targets were established using probability techniques relating generating availability and potential load forecast errors to a probability that for some hours of the year the load could not be supplied. These reserve margins were formally established as design requirements. The most commonly used target was one day in ten years.

[158]NERC Planning Standards at www.NERC.com. See Chapter 10 for a discussion of NERC and FERC's role with respect to standards.

These probability techniques modeled the effects of having interties with neighboring systems and they demonstrated that relying on emergency assistance from neighboring areas could result in dramatic reductions in installed reserve requirements for both areas, providing that the transmission interties were capable of supporting the power transfers. The probabilistic techniques are called loss of load probability for capacity-constrained systems, or loss of energy probability for energy-constrained systems.

The adequacy requirement was removed when the NERC standards were developed based on the philosophy that the marketplace should determine the level of installed reserve. However, most, if not all, reliability regions have retained a requirement for some level of installed generation reserve.

Various versions of a market approach are used when areas solicit the required reserve. These various market approaches are called an ICAP—Installed Capacity Market. The required level of installed reserve in each area is dependent on the electrical characteristics of that area: magnitude and duration of peak loads, size of generating units, generator outage rates, and so on. See Chapter 5 for additional information.

The next step in the traditional planning process was to decide on the specific generating types that would comprise the mix. The starting point was always the existing installed base of generation. Analyses were made to determine whether any of these generators should be retired during the forecast period. Typically, generator units might have useful lives of 40 or more years. In a regulated system, the older generators might have significantly higher operating costs than newer generators but these were somewhat offset by a reduction in their capital investment due to depreciation. The resulting capital and operating costs were rolled into an average system rate charged to customers. For some existing units, an option was a major overhaul and rebuilding, sometimes referred to as life extension.

New generation options had two dimensions: the technology to use and whether the utility should go it alone or become part of a group building a unit to share the financial burden and the risks. Generation types were selected based on the number of hours the new unit was expected to run. For example, if the capacity needed was only during peak hours, a peaking unit would be selected. Peaking units would involve a low capital cost, relatively high operating costs, and short lead times. Conversely, if the unit were to run almost continuously, a base-load design would be selected. These units typically have high capital coats but low operating costs. Availability of sites for the generation, including land, cooling water, and means of delivering fuel, were considered as well as the costs and availability of various fuel options. Expansion plans covered multiyear periods so that individual decisions to add specific types of capacity were made in a broader context.

The options were screened and evaluated using programs that modeled the yearly dispatch of all units in the system or power pool in which the unit would operate. These production costing programs considered yearly load shapes, generation maintenance and unavailability, sales and purchases from adjoining areas, intra- and interarea transmission capacity, and individual generator fixed and variable running costs, including fuel costs, versus electrical outlet (heat rates). Economy sales usually were made based on splitting the resulting savings equally.

12.3 TRANSMISSION PLANNING

NERC identifies a number of objectives when it discusses the purposes of the transmission system:[159]

- Deliver electric power to areas of customer demand. Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.
- Provide flexibility for changing system conditions. Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.
- Reduce installed generating capacity. Transmission intercon-

[159]NERC Planning Standards I, System Adequacy and Security—Discussion.

nections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.
- Allow economic exchange of electric power among systems. Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

NERC's standards cover the types of contingencies on the power system that must be examined for conditions with all facilities in service and with facilities out of service for maintenance while delivering generator output to projected customer demands and providing contracted firm (nonrecallable reserved) transmission services, at all demand levels. These contingencies can result in the loss of single or multiple components. For each of the contingencies, the system must be stable and applicable thermal and voltage limits must be observed. For the loss of multiple components, the controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (nonrecallable reserved) power transfers may be necessary. These analyses are performed using digital simulation programs requiring vast amounts of technical information concerning the transmission lines, customer loads, and the turbine generators.

The standards also require evaluation of the risks and consequences of a number of extreme contingencies such as the loss of all circuits on an R-O-W, all generators at a generating station, or failure of circuit breakers to clear a fault. Individual regions may develop their own regional planning criteria to reflect circumstances applicable to their own situation. These regional criteria are evaluated by NERC to ensure consistency with NERC's planning standard.

NERC also covers in its planning standards:

- Reliability assessments
- Facility connection requirements
- Voltage support and reactive power
- Transfer capability
- Disturbance monitoring

The present complexity of the NERC standards reflects the changing state of the electric utility industry. When NERC and the regional councils were first formed, their membership was almost entirely utilities and the rules, standards, and best practices that were produced relied on voluntary observance by the members. As the industry has moved to its present structure with many more participants, NERC has been working to make the planning and operating rules for the utility industry clear, universal, and well documented. To do this has meant that the volume of the associated material has grown to a point that no one text could hope to cover it all. As the footnotes indicate, individuals wishing more detail on these matters can find them at NERC's website, www.nerc.com.

As a generation expansion pattern was being developed, transmission planners would address the transmission expansion needed to accommodate the generation and the forecast load growth. Development of a transmission plan has been described as part science and part art.

There are three situations that confront the transmission planner:

1. Connect a new generator or generating station to the grid
2. Connect a new substation to the grid
3. Reinforce the existing grid

One of the issues that the transmission planner has to address is the design objective he/she must achieve. Delivering power from a new generator to the grid is a fairly straightforward objective. Reinforcing the grid is less so, since the question that must be answered is what is the performance objective being sought for the grid. This requires a definition of the required transmission capability being sought, which in turn depends on assumptions as to future generation additions and a notion of power transfer requirements.

The obvious first step for connecting a new generator or a new distribution substation is to build one or more lines to the nearest bulk power substation. However, this may not be sufficient or adequate. An examination is needed to see if the capability of the existing grid is sufficient to accommodate either. This examination has to consider a wide range of operating conditions, including different load levels, different power transfer patterns on a grid, and various maintenance outages. The analysis should evaluate a number of years into the future, including additional generation and distribution substation requirements. It may well be that because of future developments, larger and more robust facilities should be installed initially or, even, that future expansion may mitigate the need for facilities now. For example, if generation is presently being sited outside a generation-deficient load area, an initial reaction might be to build a large scale transmission development in that area. What if, however, subsequent generation additions are within the generation-deficient area? The result could be that the transmission additions could be lightly loaded and not carry enough power to pay for their costs.

An important consideration is that the required transmission additions may not always be near the new generation. The restriction on the capacity of a section of the grid can be far removed from the new generator addition. Other instances have been seen in which new lines are added to increase stability margins although they carry little if any power themselves.

After examining the need over a sufficiently long time span, decisions are needed on the voltage level of the new line(s), their thermal capacity, their terminal locations, and the circuit breaker arrangements at these locations.

Transmission System Planning Studies

Power Flow Studies. The transmission planning process uses a number of simulation programs. One is called a load flow or a power flow. This program solves Kirchoff's equations for a moment in time. It provides, for each condition for a given network topology, load level and generation schedule, the resultant real and reactive power flows in each line and transformer, the voltage at each bus, and the mVAr output of each generator.

The simulation requires an enormous amount of information from the individual utility and from all utilities whose operations might interact with the planner's system. Due to the interconnected nature of the bulk power transmission system, this requires modeling of large geographic sections of the country in enough detail to capture the effects of power flows on all adjacent systems or resulting from the generation/load patterns in all adjacent systems. The model allows each control area to be modeled separately. Each Balancing Area is identified usually by attaching an identifier to each bus and a targeted interchange is specified. The mW output of one generator in each area is designated as being variable to balance the area's interchange to the desired level.

Repeated simulations allow the planner to evaluate the performance of the system at various levels of power transfer before and after various contingencies such as the loss of a transmission line, transformer, or generator. In some areas of the country, since the electric system is considered electrically tight,[160] the planner can interpolate the results of various contingencies to determine the limiting contingency, the limiting element, and the limiting level of power flow.

Stability Studies. These studies examine the dynamic performance of a power system when it is subjected to a disturbance. Chapter 6 contains descriptions of the various types of instability the planner must consider. The starting point for the analyses is a solved power flow. The NERC standards specify the types of disturbances to consider: various fault conditions, loss of a generator, or loss of a large block of customer load. The simulation attempts to determine if the power system can return to a new stable state after the disturbance. The simulations usually examine a period of seconds after the initial disturbance. In addition to the technical information needed for power flow analyses, additional information is required for both generators and turbines and transmission line relay protection characteristics. These simulations require much more computing time than do power flows.

Short-Circuit Duty Studies. In some areas, short-circuit duties are a problem. Short-circuit duty refers to the ability of a circuit breaker to interrupt the current that flows to a fault or of the strength of the physical structure of all the elements of the substation (bus, transformers, etc.) to withstand the mechanical forces that result from the fault current. These fault currents can be significantly greater than those currents experienced in normal operation. Considerations involved are: the number of phases involved in the fault, the impedance of the fault, and the electrical proximity of the generating sources (sources of current).

Planners must evaluate the interrupting capability required at all new substations and at all existing substations since both will be affected by new generation. In most instances, the interrupting

[160]The electrical angle across the system is small, such that variations in the electrical performance can be considered to be linear.

capability can be achieved by purchasing circuit breakers of sufficient capacity and/or by upgrading existing breakers. In some instances, the required circuit breaker capacity cannot be purchased. In other cases, a complete substation rebuild may be required to provide needed mechanical strength at a very high cost. Other solutions may be needed. These solutions include:

- Installing fault-current-limiting devices such as series reactors
- Changing the system configuration by opening bus ties or using back-to-back DC

12.4 LEAST COST PLANNING

In the past, planners evaluated the means by which the forecasted peak load could be supplied using various generation resources. Starting in the 1970s, a process known as least cost planning came into wide use. Trade-offs were made between adding new generation and instituting programs to reduce customer peak load.[161] As discussed in the customer load section, peak loads occur for very few hours a year. Reducing the peak load in some cases was a less costly alternate than building new generation. At the time, the financial yardstick was not profits but rather minimum revenue requirements from customers.

12.5 THE NEW PLANNING ENVIRONMENT

Both the objectives and the process of planning have changed. The degree of change depends on the area of the country and how far local regulatory authorities have moved the restructuring process; that is, has generation divestiture and/or retail access been implemented? As a matter of national policy, wholesale power producers are encouraged and given access to the transmission grid under the same terms and conditions as the local utilities.

The generation planning process has changed in the new environment to the extent that a global approach is no longer used. As noted earlier, NERC no longer has criteria defining the minimum acceptable level of generation reliability. Some regional

[161]Over time, pressure mounted in some jurisdictions to expand the customer programs from a peak load reduction focus to an energy reduction focus.

areas retain a required generation reserve and some do not. Generation pricing is based on the market, not on costs. With many different companies building power plants, each decision to build is made with less certainty of what the competitive situation will be going forward. The selection of unit sizes, types, and fuel is made with a view toward those that will be the most profitable, not necessarily toward those that will result in the overall lowest costs to the consumer. Many felt, perhaps foolishly, that the market would drive prices down.

The planning of the electric transmission system has both a technical and a commercial/regulatory aspect. Due to a variety of reasons (local opposition facilitated by extensively long regulatory and judicial review of proposals and by the uncertainty about the level of returns that regulators would allow as the new markets developed), very little transmission was built in the 1990s. Compounding the problem was that the new entities charged with operating the transmission system (ISOs and RTOs) did not have the authority or resources to plan, finance, and construct transmission. In a series of orders, some driven by provisions of EPAct05, FERC has attempted to address the problem. FERC's actions in this regard are discussed in Chapter 14.

The design objective for the transmission system is being expanded to include provision for sufficient transmission capability to facilitate a geographically wide-scale wholesale power market. Following the national election of 2008, there is a strong potential for significant transmission additions needed to incorporate new renewable power sources sited remotely from existing transmission corridors.

Addressing the changing environment, in Order 2000, FERC designated the RTO as having ultimate responsibility for both transmission planning and expansion within its region:

> We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities.[162]

Figure 12-1 indicates the areas where RTOs and ISOs were established in response to FERC's order. Since power pools were

[162]FERC Order 2000.

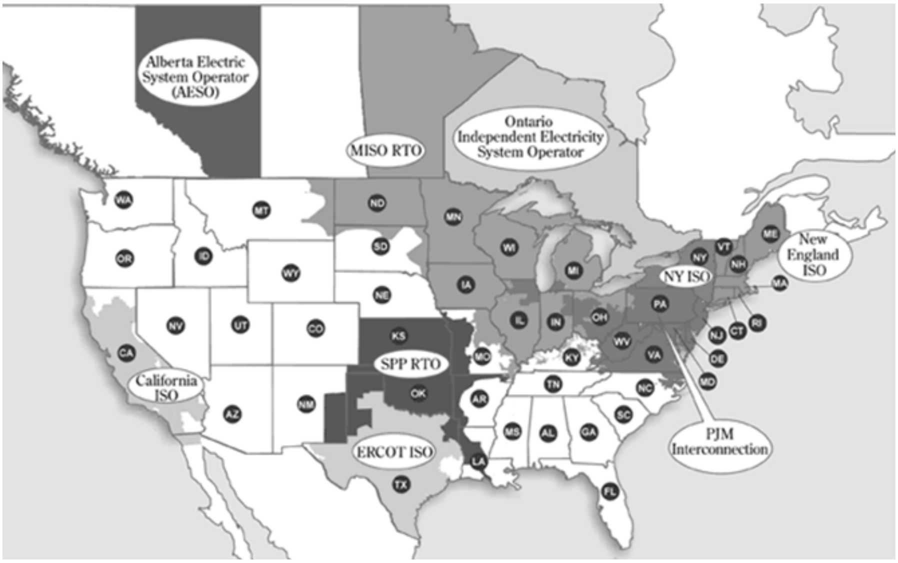


Figure 12-1. Names and locations of RTOs and ISOs. Source: Platts POWERmap, 2007.

owned and managed by their member utilities, FERC was concerned that there was too close a relationship, carrying with it the potential of the utilities controlling the operation of the grid. To this end, it encouraged the formation of ISOs, which are managed by independent individuals. Most, if not all, of the old power pools were restructured into ISOs. The mission statements of two power pools that converted to ISOs—the New York Power Pool (NYPP) and the Pennsylvania-New Jersey-Maryland Interconnection (PJM), which became NYISO and PJMISO—are typical:

- New York's mission is ". . . to ensure the reliable, safe, and efficient operation of the State's major transmission system and to administer an open, competitive, and non-discriminatory wholesale market for electricity in New York State."
- PJM Interconnection's core mission has not wavered from its three central responsibilities: ensuring the reliability of the regional electricity grid; managing fair, nondiscriminatory and efficient wholesale electricity markets; and operating in an independent manner.[163]

[163]PJM Annual Report 2007.

Addressing a concern that state regulators have essentially a veto power over transmission lines planned to accommodate interregional power flows, EPAct05 contained a section dealing with transmission congestion and National Interest Transmission Electric Transmission Corridors. It required that DOE conduct a study to identify such corridors. FERC was given authority to grant certification to transmission facilities proposed for these corridors, subject to FERC review.[164] As part of its rules, FERC required that the application process assist the Commission to determine if proposed transmission facilities

- Are eligible for an electric transmission construction permit
- Are in the public interest
- Will reduce transmission congestion and protect and benefit consumers
- Are consistent with sound national energy policy and will enhance energy independence
- Maximize the use of existing facilities.

EPAct05 directed the Commission to develop incentive-based rate treatments for transmission of electric energy in interstate commerce, adding a new Section 219 to the Federal Power Act. The rule implemented this new statutory directive through the following incentive-based rate treatments:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies, or transcos)
- Full recovery of prudently incurred construction work in progress
- Full recovery of prudently incurred preoperations costs
- Full recovery of prudently incurred costs of abandoned facilities
- Use of hypothetical capital structures
- Accumulated deferred income taxes for transcos
- Adjustments to book value for transco sales/purchases
- Accelerated depreciation
- Deferred cost recovery for utilities with retail rate freezes
- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators

[164]http://www.ferc.gov/industries/electric.asp

In Order 890, issued in February 2007, FERC spoke to the issue of planning:

> Transmission planning is a critical function under the pro forma OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of nontransmission alternatives. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans are developed. These deficiencies are serious, given the substantial need for new infrastructure in this nation.

Responding to this concern, FERC, in its order, designated nine planning principles to be addressed in each area's open access transmission tariffs (OATTs)

1. Coordination
2. Openness
3. Transparency
4. Information exchange
5. Comparability
6. Dispute resolution
7. Regional participation
8. Economic planning studies
9. Cost allocation for new projects

It is fairly typical to have a lengthy list of proposed new generation in each state. However, only some of the proposals are being implemented. Approval of new power plants is done under regulatory rules, which vary state by state. In some states, the process is relatively rapid, in others it is not. Merchant power plant owners obviously will opt for construction in supportive regulatory jurisdictions. This then translates into an increased need for transmission capability to move power from these states to states where power plant construction is hindered, since these latter markets probably will have higher market clearing costs.

While some stress the requirement to plan a transmission system that will facilitate the electricity market, others stress the need to focus on providing adequate reliability at minimum cost. Although the goal of designing a system to facilitate a wholesale power market is commendable, the means for doing so have become extremely complex due, in large part, to structural changes being implemented to establish the markets.

Transmission planning used to involve dealing with a more or less consistent pattern of power flow from known sources to known load pockets. Even then, in many areas the time it took to plan and get approval for new transmission lines could take many years, even when there were relatively few regulatory jurisdictions involved. Going forward, the level of uncertainty has increased dramatically. Uncertainties are of technical and structural/financial natures. Among them are:

- How much transmission capability is needed, in both directions, across each and every existing and future interface and flowgate?
- How is the magnitude of this capability determined since:
  - In spite of the many numerous proposals to build merchant power plants, the likelihood is that many will never be built
  - The unknown locations and sizes and dispatch patterns of those that will be built
  - The future of existing power plants may be unknown
  - The impact of dispersed generation is unknown
  - Of those power plants built, how will they be dispatched, given the commercial sensitivity of the contractual arrangement that they will enter into for sale of the power or the bidding strategies they will use?
- How will variations in the assumed or best-guess generation-expansion plan impact a transmission development plan?
- How will trade-offs between different generation options, FACTS device applications, and load curtailment measures be identified and evaluated given the different financial perspectives of the various involved parties?
- Is there any potential for realizing economies of scale, such as building a higher voltage line initially instead of a series of lower voltage/capacity lines?
- Can lines ever be built solely for reliability purposes?
- Who will finance and build the transmission?
- What will be the rules for paying for use of the transmission?
- What types return on transmission investments will be needed?
- Given the uncertainties involved, how can a plan gain the requisite regulatory approvals, especially if multiple jurisdictions are involved? These include

Responsibility for planning, construction, and operation
Planned by companies and power pools
Company- and pool-controlled planning process
Company, pool, and regional council reliability criteria
Company and pool economic criteria
Company investment and construction
State approval
Regulated return on investment
Clear responsibility for costs
Contentious selection of new rights-of-way

The methods used to manage these and other uncertainties have been summarized on an international basis by CIGRE.

Recent Transmission Projects

As a result of FERC's actions in bringing some certainty to both the transmission line approval process and to the rules dealing with the allowed return on transmission investments, a number of proposals have been made for new transmission lines. A significant aspect of these proposals is the role of newly formed for-profit transmission companies, some with ties to old-line utilities but some entirely new without utility ties.

Another area of activity is the studies to develop conceptual plans for massive reinforcements of the transmission grid to integrate and deliver large developments of renewable power, especially in areas where there is presently little or no transmission. Addressing this issue, in 2009, the U.S. House of Representative drafted another energy bill, H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES Act), addressing, in part, transmission planning. Subtitle F—Transmission Planning—this act includes Section 151, Transmission Planning, which

> Amends the Federal Power Act to establish a federal policy on electric grid planning that recognizes the need for new transmission capacity to deploy renewable energy as well as the potential for more efficient operation of the current grid through new technology, demand-side management, and storage capacity. Enhances existing regional transmission planning processes by incorporating this federal policy. Charges the Federal Energy Regulatory Commission with supporting, coordinating, and integrating regional planning efforts.

CHAPTER 13

THE REGULATORY NETWORK: LEGISLATION

The physical network has been described in prior chapters. A second, and equally important network, is the regulatory network. The functioning of this network is completely controlled by human beings and human decisions. It plays a vital role in the functioning of all the other networks, sometimes providing specific rules for their functioning while at other times providing restraints within which their operation must be conducted. From time to time, failures to recognize the need for the regulatory network to be consistent with the physics and operational requirements of the other networks has resulted in problems that have increased costs and decreased the reliability of electric power systems. The market failures in California in the early 2000s and many other regions in the United States provide outstanding examples.

13.1 PRICING AND REGULATION

The reconciliation of the interests of the private ownership of the facilities and systems that provide electric power and the public interest character of their business is accomplished by the concept of regulation. Regulation refers to the laws, and the actions of tribunals established under those laws, governing the business of utilities.

The concept of regulation of private business in which public has an interest is not a new one. As long ago as the reign of the Roman Emperor Justinian, laws were passed regulating the business of privately owned docking facilities, assuring access to all interested individuals. There were a limited number of choice sites for docks and once those were occupied, other commercial interests were effectively denied access, which was recognized as detrimental to the necessary commercial activities of the Empire. Since that time, granaries, grist mills, breweries, thoroughfares, and a number of other activities have been considered so important to the public interest that special laws were passed regulating such businesses.

Electricity providers are regulated at the federal, state, and local levels. Every state has a regulatory agency directly concerned with the activities of utilities. The U.S. government has several agencies supervising various aspects of utilities. Local municipalities regulate land use and, in some cases, certain franchise aspects.

In the past, the principal regulation of electric utilities was by state regulatory authorities. Federal regulation was generally limited to activities involving interstate commerce or situations in which the national interest was affected. With the passage of EPAct92 and EPAct05, the role of Federal regulators has been greatly expanded. The role of the regulator now includes support for the development of open and fair wholesale electric markets, ensuring equal access to the transmission system and more hands-on oversight and control of the planning and operating rules for the industry.

13.2 FEDERAL LEGISLATION[165]

The foundations of federal regulation of electric utilities are the Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) of 1935 and its many amendments over the years.

13.3 FEDERAL UTILITY HOLDING COMPANY ACT (PUHCA)

One little known fact about President Franklin D. Roosevelt (FDR) is that he became a utility rate expert when he was Governor of New York State. He learned that multistate utility holding companies could undo the efforts of even the best state utility commission because the state could not regulate the parent companies in

[165]We are indebted to Ms. Lynn Hargis, Esq., an energy attorney for Public Citizen, for personal correspondence and information on the material provided herein.

their interactions with the state operating utility. When he became President, FDR tried to outlaw utility holding companies, believing that they could not be adequately regulated, but he lost on that score and only got PUHCA. Still, PUHCA contained two hugely effective provisions:

1. Utility holding companies were confined to a single geographic region so that states could regulate their transactions with affiliates, or they had to "register" with the Securities and Exchange Commission (SEC), which would regulate them extensively under PUHCA.
2. The owners of such "registered" holding companies had to get rid of nonutility businesses. This had a tremendous impact on the regulation, structure, and size of utility parent companies. PUHCA prevented the recreation of giant "power trusts," and protected U.S. utility investors and utility regulation for seventy years.

The whole structure of most U.S. utilities was based on their parents, or holding companies, being forced by PUHCA to confine their utility operations to a single state, in which the holding company was also incorporated, so that such holding companies could be exempt from registration and extensive regulation by the Securities and Exchange Commission (SEC) under PUHCA. This meant that states could effectively regulate most holding companies and, therefore, most state utilities and their rates. It also meant that there were size limits on even multistate utility holding companies. After the great utility crash in the 1930s, most countries nationalized their public utilities, as did France, which is why many of them are now privatizing. It is likely that FDR saved investor-owned utilities in the United States by ensuring they were effectively regulated under either PUHCA or state law.

The following comments by a knowledgeable attorney, Lynn Hargis, are particularly noteworthy:

> With the PUHCA repeal in 2005, utility holding companies have no incentive to so restrict their size and operations, which means that, once again, state commissions cannot effectively regulate state utilities, because they cannot regulate their multistate parents. There is also no longer any limit on the size of such multistate holding companies, so Exelon, for example, is proposing to acquire NRG and become the largest electric hold-

ing company in U.S. history, with enough power to supply the electricity of over one-third of American households, according to the company. If successful, Exelon will set an example for others, and there will soon be a race to be the biggest, à la Exxon–Mobil and Chevron–Texaco.

Also, because multistate utility holding companies can now own other nonutility businesses, there is a huge potential for conflicts of interests between the utility business and other riskier ones. For example, there is now nothing to stop insurance companies, investment banks, and oil companies from also owning and controlling huge electric utility systems. There is also now no utility law that prohibits foreign companies owned by foreign states from owning and controlling huge U.S. utility systems. FERC has just approved the acquisition of half Constellation's nuclear operations by EDF, a French utility owned and controlled by the French government. This effectively means that some American nuclear plants have become nationalized, but not by our *own* government, raising concerns about nuclear wastes and security exposure.

As for investment banks owning utilities, the original purpose of PUHCA was to control such investment banks, after a huge collapse of utility holding companies in 1931–1932, when 53 utility holding companies went bankrupt and another 23 defaulted on loans, causing the wipeout of the savings of millions of widows and orphans and others who owned utility stocks and bonds.

Instead of unlimited loans based on mortgages, the utility holding companies took out unlimited loans for all their riskier affiliated business, all based on the revenues of their public utility operating companies at the bottom of the ownership pyramid. When the banks collapsed at the start of the Great Depression, they called in their loans and the holding companies went down.

13.4 FEDERAL POWER ACT

The Federal Power Act (FPA) of 1935 gave the Federal Power Commission ("FPC")[166] regulatory power over the terms, conditions, and rates of interstate and wholesale transactions and trans-

[166]The FPC had been established under the Federal Water Power Act of 1920 to encourage the development of hydroelectric power plants. The Commission originally consisted of the Secretaries of War, Interior, and Agriculture.

mission of electric power to ensure electricity rates that are “reasonable, nondiscriminatory, and just to the consumer.”

The FPA changed the structure of the FPC so that it consisted of five commissioners nominated by the President for five-year terms, with the stipulation that no more than three commissioners could come from the same political party.[167] It directed the FPC to divide the country into regional districts for “voluntary interconnection and coordination.” The Commission had the duty to promote and encourage such interconnection and coordination. The FPC also had the authority, when applied for by a utility, to order another utility to physically interconnect and to sell or exchange energy.

In order for FERC to ensure that rates are lawful, the Federal Power Act requires that all wholesale electric rates and rate contracts must be filed at the FERC for agency and public inspection, and that any change or increase in such rates and contracts must be publically filed in advance so that FERC may order hearings, impose refunds, and suspend collection of the new rates for up to five months if the rates appear particularly excessive.

For its first 50+ years, the FPC and FERC regulated wholesale sales and transmission rates on the basis of the cost to provide the service plus a reasonable rate of return on the utility’s investment. (Return of investment was generally treated as an expense for depreciation.) Rates were filed, set for hearing subject to refund, and the FERC staff and utilities would argue over the proper level of prudent expenses and what was a reasonable rate of return. If the increased rates were found to be excessive after the hearing, the utility had to make refunds with interest to its wholesale customers.

In the late 1980s and 1990s, deregulation was preached and a push was made for FERC to allow so-called market-based rates that permit electricity sellers to charge whatever the market will bear as long as FERC has determined that the seller lacks market power. FERC initially gave such market rate authority only to isolated independent power plants, but it soon determined that virtually no seller, even huge registered holding companies, had market power. After the California market debacle of 2000–2001, FERC slightly tightened and capped its market power requirements, but today most wholesale sellers enjoy market rate tariffs

[167]From FERC Website www.ferc.gov/about.

that allow them to charge whatever they can negotiate with the wholesale buyer.[168] And, unlike state-regulated utilities that enjoy a monopoly franchise in exchange for "the obligation to serve" every customer within their territory, wholesale sellers have no obligation to serve. This means that they need not build transmission lines, nor, indeed, build power plants. As a result, FERC now encourages construction of power plants where they are needed by allowing customers to be charged higher rates for "locational" power plants. FERC is also providing financial incentives to encourage the building of transmission lines, even though these are clearly monopoly facilities, by offering higher incentive rates of return rather than requiring construction as part of a utility's obligation to serve.

FERC has been challenged in the courts that its market-based tariffs, with after-the-fact reporting requirements, do not satisfy the requirement of the Federal Power Act that all rates must be filed for FERC and public review, and advance notice of any changes in such rates must be made so that FERC can determine whether to hold a hearing, order refunds, and so on. Critics of market-based rates also contend that FERC lacks a standard for determining how to recognize an unjust and unreasonable rate under its market-based program, which simply says that all rates negotiated by the parties are lawful, even though wholesale buyers can, by law, pass their prices on to retail utility customers without state interference. In June of 2008, the U.S. Supreme Court acknowledged that, although two lower courts had generally approved FERC's market-rate program, the Supreme Court itself had not and would not do so in the case before it.[169] Moreover, the Supreme Court said that FERC's claim that approval of a market-rate tariff satisfied the agency's duty to review filed rate changes in advance appeared to the Court to rest on a "somewhat metaphysical ground."

[168]State utility commissions must permit wholesale charges allowed by FERC to be passed through to retail consumers under federal preemption doctrines. As a result, courts have held that wholesale buyers may lack adequate incentive to "negotiate" strongly regarding the prices they pay, even if they have the ability to do so, because they can simply pass along such charges to retail ratepayers. See *Tejas Power Corp. v. FERC,* 908 F.2d 998 (D.C. Cir. 1990).

[169]Morgan Stanley Capital Group v. PUD #1 of Snohomish Co., et al., 28 S.Ct. 2733, at 2741, 2747 (2008).

13.5 OTHER 1930 FEDERAL LAWS

In the 1930s, other acts were passed that supported and encouraged the development of publicly owned utilities or the sale of power generated at power plants owned by governmental organizations:

- 1933—The Tennessee Valley Authority Act (TVA) dealt with the provision of electric service in what were then rural areas. The TVA was authorized to generate, transmit, and sell electricity. It could build transmission lines as needed.
- 1936—The Rural Electrification Act (REA) allowed loans to organizations providing electricity to sparsely populated rural areas.
- 1937—The Bonneville Power Act created the Bonneville Power Administration, responsible for the transmission and marketing of power from federally constructed dams.
- From 1935 to 2005 the Public Utility Holding Company Act (PUHCA) established the rules for the creation and oversight of electric utility holding companies. This Act was passed to address many abuses including pyramid financial structures with very high levels of debt, inadequate disclosure of the financial position and earning power of holding companies, unsound accounting practices, and abusive affiliate transactions of the holding company structure that occurred in the 1920s and early 1930s. The Energy Policy Act of 2005 repealed PUHCA.[170]

13.6 DEPARTMENT OF ENERGY ORGANIZATION ACT

In 1977, the Department of Energy Organization Act created the Department of Energy.[171] The law consolidated organizations from a dozen departments and agencies. Under this legislation, the FPC was replaced by the Federal Energy Regulation Commission (FERC).

[170]The full text of this Act is available online at www.law.cornell.edu/uscode/15/ch2C.html.

[171]See Chapter 14 for a discussion of DOE's role with respect to the electric utility industry.

13.7 PUBLIC UTILITY REGULATORY POLICIES ACT (PURPA)

The Public Utility Regulatory Policies Act (PURPA) of 1978 was one of a group of acts enacted in 1978 by Congress under the composite name of the National Energy Act (NEA). The NEA also included the National Energy Conservation Policy Act, the Power Plant and Industrial Fuel Use Act, the Energy Tax Act, and the Natural Gas Policy Act. Congress was responding to a number of issues that occurred during the 1970s that were impacting the cost or availability of power:

- The Mid East oil embargo, which affected both the cost and security of the nation's oil supply
- A perceived developing shortage in the nation's proven reserves of natural gas[172]
- The rapid and steep increase in the cost of building nuclear power plants
- The impact on power plants resulting from the Clean Air Act and other environmental legislation of the period
- The slowdown in economic growth negatively impacted electric consumption, making many new power plants unneeded, although the utilities were looking to recover their investments by raising their rates

The many reasons cited in the literature for passing these laws can be combined into four main categories:

1. Lower the nation's oil and gas use
2. Lower customer consumption by promoting efficiency
3. Diversify the industry by promoting alternate energy technologies
4. Lower costs to the consumer

PURPA encouraged the development of alternative generation sources designated as qualifying facilities (QFs). There are two main types of QFs:

1. Cogenerators that use a single fuel source to produce electric energy as well as another form of energy, such as heat or steam

[172]The shortages disappeared after price controls on natural gas were lifted in the 1980s and development began again.

2. Small power producers that use renewable resources, including solar, wind, biomass, geothermal, and hydroelectric power as their primary energy source. Each generator has to have a capacity less than 80mW.

QFs were exempted from regulation under PUHCA and the FERC so that the limitation on ownership contained in the PUHCA was bypassed. PURPA originally prevented electric utilities and electric utility holding companies from owning QFs. This was finally changed to allow them to own 50% of a QF.

Under Section 210 of PURPA, local utilities were required to purchase power from QFs at a price set by state public utility commissions, which was not to exceed the utility's avoided costs, and to sell backup power to QFs. The amounts to be paid to the OFs were fixed for the length of the contracts. In many instances, the estimates of avoided costs used by some state commissions proved to be too high because of excessively high forecasts of future oil prices for the conditions then existing. Subsequently, many utilities found themselves with obligations to buy power in the new marketplace at prices significantly above the prevailing levels. These contractual obligations were a major component of the stranded cost issue that affected many utilities' positions in the 1990s as the industry moved to a new posture on the ownership of wholesale generation.

Some states required utilities to enter into contracts with QFs even when the utilities did not require the capacity. Recognizing these problems, in the late 1980s some states implemented competitive bidding procedures for required new capacity.

The development of QFs had mixed results in the short term. Additional generating resources were built using alternate or more efficient fuel but at the cost of steadily increasing prices for electricity. Regardless of the original rationale, PURPA's longer term effect was to introduce competition into the generation sector of the electricity market because the long-term contracts that utilities were required to enter into with QFs at fixed rates enabled the QFs to obtain financing under loan agreements for a period long enough to pay off construction costs. It was assumed that non-QFs could simply finance generating plants.

This act also strengthened the FERC's power to order interconnections if they are in the public interest or encourage conservation. The Commission was also given the authority to require a utility to provide transmission service (wheeling) to another utility. The Commission could order a utility to provide such service if it found that it:

(1) is in the public interest,
(2) would
  A) conserve a significant amount of energy,
  B) significantly promote the efficient use of facilities and resources, or
  C) improve the reliability of any electric utility system to which the order applies . . .

Certain conditions had to be met before the Commission could order interconnection or wheeling. The conditions included:

- Does not cause uncompensated economic loss
- Does not place an undue burden
- Does not impair reliability
- Does not impair ability to render adequate service

The Commission could also exempt electric utilities from state laws, rules, or regulations that prevent voluntary coordination. PURPA also directed the Federal Energy Regulatory Commission to "study the opportunities for (1) conservation of energy, (2) optimization in the efficiency of use of facilities and resources, and (3) increased reliability, through pooling arrangements. The Commission could recommend to electric utilities that such utilities should voluntarily enter into negotiations where the opportunities for savings exist. The Commission was required to report annually to the President and Congress regarding any such recommendations and subsequent actions taken by electric utilities, by the Commission, and by the Secretary under this Act, the Federal Power Act, and any other provisions of law.

Some of the key provisions of PURPA were amended by EPAct05 as discussed in the Section 13.9.

13.8 ENERGY POLICY ACT OF 1992 (EPACT02)

This wide reaching act contained further modifications to PUHCA and to the FPA intended to further move the nation toward a market-oriented approach to electric supply by further increasing competition in the generation sector.

It did this by modifying PUHCA to allow a new class of generation ownership, called Exempt Wholesale Generators (EWGs), to engage in the wholesale electric power market:[173]

- EWGs are free from regulation under PURPA and PUHCA
- Both registered and exempt holding companies can own EWGs
- Utilities can buy electric energy from EWGs with which they have affiliated

The law included provisions that require state regulators to review certain aspects of the financial implications of long-term wholesale power contracts between utilities and EWGs. State PUCs have access to the "books, accounts, memoranda, contracts, and records of" any EWGs selling electricity to a utility subject to its jurisdiction, to the EWG, and to any company associated with the EWG, including another utility or a holding company.

The act also allowed, subject to certain restrictions, exempt holding companies to purchase one or more foreign utilities.[174]

FPA Modifications

In order to provide a wide market for this new generation, the FPA was modified to require any utility providing transmission service to supply such service to anyone generating electric energy for sale for resale. The act required that the transmitting utility enlarge its transmission capacity where necessary to provide such services. The intent was to create an open-access transmission system. FERC was given authority to issue orders to implement this policy provided that the reliability of the electric systems affected by such an order would not be impaired.

The law contained two perspectives on the use of the transmission system:[175]

[173]See CRS Report to Congress, "Electric Restructuring Background: The Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992," by Amy Abel.

[174]To enable investments by existing electric utilities in EWGs and to purchase or invest in foreign utilities, a large number of new holding companies were formed in the United States in the 1990s.

[175]"Wholesale transmission services are to be provided at rates, charges, terms, and conditions which permit the recovery by such utility (the transmitting utility) of all of the costs incurred in connection with the transmission services, in-

(continued)

1. The owners of the transmission were to be adequately compensated for the use of the transmission
2. The rates charged should be economically efficient, just and reasonable, and not unduly discriminatory.

13.9 THE ENERGY POLICY ACT OF 2005 (EPAct05)

The Energy Policy Act of 2005 (EPAct05) contained a number of laws enacted to address a wide range of U.S. energy policies including diversification of its energy supply, reduction of its dependence on foreign oil, increasing energy efficiency, and conservation, improvement of vehicle energy efficiency and modernization of its energy infrastructure. This Act was in response to a number of factors:

- The nation's increasing negative balance of payments for foreign oil, especially as the price of oil rapidly increased
- Concern over global warming and the emission of carbon from combustion of gasoline in cars and carbon based fuels in power plants
- The 2003 Northeast blackout and many of the lessons learned from the analysis of its causes
- Concerns over aspects of the rules instituted by FERC for the wholesale electric market in the United States

There are 18 Titles in the Act, many of them directly or indirectly impacting the electric power industry. The Titles are I—Energy Efficiency, II—Renewable Energy, III—Oil and Gas, IV—Coal, V—Indian Energy, VI—Nuclear Matters, VII—Vehicles and Fuels, VIII—Hydrogen, IX—Research and Development, X—Department of Energy Management, XI—Personnel and Training, XII—Electricity, XIII—Energy Tax Policy, XIV—Miscellaneous, XV—

cluding, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities. Such rates, charges, terms, and conditions, shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable, and not unduly discriminatory or preferential." The Energy Policy Act of 1992, Title VII—Electricity, Subtitle B—Federal Power Act; Interstate Commerce of Electricity, Section 722, Transmission Services.

Ethanol and Motor Fuels, XVI—Climate Change, XVII—Incentives for Innovative Technologies, and XVIII—Studies.[176,177]

EPAct05 had three principal policy goals that relate to the electric utility industry:

1. To reaffirm a commitment to competition in wholesale power markets as national policy
2. To strengthen FERC's regulatory tools
3. To provide for development of a stronger energy infrastructure

Title XII, Electricity, is called the Electricity Modernization Act of 2005 and is the one that most directly impacts the operation of the electric power system. It includes 10 Subtitles, each of which has one or more sections. The Act addressed both technology and market issues. Table 13-1 gives the names of the major Subtitles of Title XII and some of the issues addressed. FERC actions on each of the subtitles are covered as appropriate throughout the text.

Subtitle E—Amendments to PURPA—provides, among other things, for termination of the requirement that an electric utility enter into a new contract or obligation to purchase electric energy from qualifying cogeneration facilities and qualifying small power production facilities (QFs) if the FERC finds that the QF has nondiscriminatory access to one of three categories of markets. FERC issued Order 688 addressing these issues.

Provisions in other Titles of EPAct05 will have longer range impacts on the electric power industry insofar as the law supports development of new or advanced technologies by either direct funding of R&D or by provision of favorable tax treatment of the new facilities that are installed. Included in this area is support of:

- Advanced nuclear generation
- Clean coal technologies
- Development of sources of renewable energy
- The use of hydrogen

This Act significantly increased the role of the Federal Government in the planning and operation of the U.S. electric utility

[176]The Library of Congress Thomas Summary of H.R. 6 can be found at: http://thomas.loc.gov.

[177]An extensive list of commentaries on the various Titles can be found at http://www.energy.wsu.edu/documents/library/EnergyPolicyAnalysis.pdf.

Table 13-1. Subtitles and a partial list of sections of Title XII of EPAct05

Title XII—Electricity	Major issues
Subtitle A—Reliability Standards	
Subtitle B—Transmission Infrastructure Modernization	Siting of interstate transmission facilities; Advanced transmission technologies
Subtitle C—Transmission Operation Improvements	Open nondiscriminatory access; Federal participation in transmission organizations; Native load service obligation; Study on the benefits of economic dispatch; Sense of Congress regarding locational installed capacity mechanism
Subtitle D—Transmission Rate Reform	Transmission infrastructure investment; Funding new interconnection and transmission upgrades
Subtitle E—Amendments to PURPA	Smart metering; Cogeneration and small power production purchase and sale requirements
Subtitle F—Repeal of PUHCA	
Subtitle G—Market Transparency, Enforcement, and Consumer Protection Sections	Market manipulation; Merger review reform
Subtitle J—Economic Dispatch	

industry as well as strengthening its oversight responsibilities of the wholesale electric markets in the country (see material on FERC in Chapter 14).

The Act increased FERC's responsibilities, including:

- Overseeing the reliability of the nation's electricity transmission grid
- Implementing new tools, including penalty authority, to prevent market manipulation
- Providing rate incentives to promote electric transmission investment
- Supplementing state transmission siting efforts in national interest electric transmission corridors
- Reviewing certain holding company mergers and acquisitions involving electric utility facilities, as well as certain public utility acquisitions of generating facilities

13.10 THE ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

This Act impacts the electric utility industry in a number of ways. In the area of electric energy demand or requirements, it sets revised standards for appliances and lighting and promotes conservation in buildings and industry. In the environmental area, it addresses expanded federal research on carbon sequestration technologies. In the area of energy supply, it provides for taxpayer funding of research and development of solar energy, geothermal energy, and marine and hydrokinetic renewable energy technologies. In the area of the modernization of the electric system, Title XIII: Smart Grid, declares "it is the policy of the United States to support modernization of the nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve specified characteristics of a Smart Grid."[178]

13.11 ENVIRONMENTAL LAWS

Table 13-2 lists the major federal laws that deal with environmental matters, many of which impact electric utilities.

The National Environmental Policy Act (NEPA) requires federal agencies to integrate environmental values into their decision-making processes by considering the environmental impacts of their proposed actions and reasonable alternatives to those actions. To meet this requirement, federal agencies prepare a detailed statement known as the Environmental Impact Statement (EIS).

The Clean Air Act is a comprehensive Federal law that regulates air emissions from area, stationary, and mobile sources. This law authorizes the U.S. Environmental Protection Agency to establish National Ambient Air Quality Standards (NAAQS) to protect public health and the environment. The goal of the Act was to set and achieve NAAQS in every state by 1975. The setting of maximum pollutant standards was coupled with directing the states to develop state implementation plans (SIPs) applicable to appropriate industrial sources in the state. The Act was amended

[178]See Chapter 8 for a discussion of activities relating to a Smart Grid.

Table 13-2. Major environmental laws impacting the utility industry

Atomic Energy Act (AEA)
Clean Air Act (CAA)
Clean Water Act (CWA)
Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, or Superfund)
Emergency Planning and Community Right-to-Know Act (EPCRA)
Endangered Species Act (ESA)
Energy Policy Act
Federal Food, Drug, and Cosmetic Act (FFDCA)
Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA)
Federal Water Pollution Control Amendments
Marine Protection, Research, and Sanctuaries Act (MPRSA, also known as the Ocean Dumping Act)
National Environmental Policy Act (NEPA)
National Technology Transfer and Advancement Act (NTTAA)
Nuclear Waste Policy Act (NWPA)
Occupational Safety and Health (OSHA)
Ocean Dumping Act
Oil Pollution Act (OPA)
Pollution Prevention Act (PPA)
Resource Conservation and Recovery Act (RCRA)
Safe Drinking Water Act (SDWA)
Superfund
Superfund Amendments and Reauthorization Act (SARA)
Toxic Substances Control Act (TSCA)

in 1977 primarily to set new goals (dates) for achieving attainment of NAAQS since many areas of the country had failed to meet the deadlines.

Congress established the New Source Review (NSR) permitting program as part of the 1977 Clean Air Act Amendments. NSR is a preconstruction permitting program that serves two important purposes.

First, it ensures that air quality is not significantly degraded by the addition of new and modified factories, industrial boilers, and power plants. In areas with unhealthy air, NSR assures that new emissions do not slow progress toward cleaner air. In areas with clean air, especially pristine areas like national parks, NSR assures that new emissions do not significantly worsen air quality.

Second, the NSR program assures people that any large new or modified industrial source in their neighborhoods will be as clean as possible, and that advances in pollution control occur concurrently with industrial expansion.

Table 13-3. Appropriations in 2009 "stimulus" legislation

Modernize electricity grid	$4,400,000,000
Fossil energy research and development	$3,400,000,000
Advanced batteries manufacturing, including lithium ion batteries, hybrid electrical systems, component manufacturers, and software designers	$2,000,000,000
Electricity grid worker training	$100,000,000
Energy efficiency and conservation block grants	$3,200,000,000
Weatherization assistance program	$5,000,000,000
State energy program	$3,100,000,000
Uranium Enrichment Decontamination and Decommissioning Fund	$390,000,000
Department of Energy science programs	$1,600,000,000
Advanced Research Projects Agency	$400,000,000
Innovative technology loan guarantee program	$6,000,000,000
Western Area Power Administration construction and maintenance	$10,000,000
Bonneville Power Administration borrowing authority	$3,250,000,000
Western Area Power Administration borrowing authority	$3,250,000,000
Leading-edge biofuel projects	$500,000,000
Federal building conversion to "high-performance green buildings"	$4,500,000,000
Energy efficient federal vehicle fleet procurement	$300,000,000

On January 1, 2000, the electric industry came under Phase II regulations of the Clean Air Act Amendments of 1990. This Act was primarily designed to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxides. Phase I, which began on January 1, 2005, affected 435 generating units. Under Phase II, coverage increased to more than 2000 units. Since 1995, some generators have overcomplied with Phase I in order to create excess allowances. This has allowed them to delay enacting additional strategies that would be necessary for compliance with Phase II. Strategies that are being used for compliance include fuel switching/blending, cofiring with natural gas, allowance acquisitions, scrubbers, repowering, and plant retirements.[179]

[179]From the EIA report, Electric Power Annual 2000, Volume 1, August 2001.

This environmental and other Federal legislation brought with it the concept of quantified emission rights. These rights can be bought and sold, thus facilitating meeting environmental requirements at minimum cost.

13.12 2009 AMERICAN RECOVERY AND REINVESTMENT ACT

In February 2009, new legislation provided significant funding levels that will have a significant effect on the future of the Country's electric supply. Table 13-3 lists the funds provided. Projects impacting the electric utility industry are assigned to various departments within the DOE. The website www.energy.gov/recovery/ provides access to information on these projects as well. At face value, significant funding has been provided for various programs to reduce energy consumption. The modernization of the electric grid falls under the generic title of Smart Grid, discussed earlier. Preliminary information suggests that the initial Smart Grid activity will focus on the bulk power system rather than the distribution/customer area.

CHAPTER 14

THE REGULATORY NETWORK: THE REGULATORS

This chapter describes the regulators who oversee various aspects of the industry. We will also cover some important recent regulations.

FERC has become a major determinant of how the power system is planned and operates. As a result of EPAct92 and EPAct05, the role of the Federal Government in planning and operations has significantly increased. EPAct92 has resulted in a series of FERC orders addressing the establishment of a wholesale electric energy market in the United States and a concomitant effort to ensure open access to the nation's transmission grid. EPAct05 has given FERC a major role in the establishment of industry planning and operating standards and in the monitoring of adherence to these standards.

14.1 THE REGULATORS

Federal Energy Regulatory Commission (FERC)[180]

The Federal Energy Regulatory Commission (FERC) is an independent regulatory agency within the Department of Energy. FERC was created through the Department of Energy Organization Act in October 1977. At that time, its predecessor, the Federal Power Commission (FPC), was abolished, and the new agency inherited most of the FPC's responsibilities.

FERC has up to five commissioners who are appointed by the President of the United States with the advice and consent of the

[180]The material in this section is from the FERC's Website, www.ferc.gov.

Understanding Electric Power Systems. By Jack Casazza and Frank Delea

Senate. Commissioners serve five-year terms, and have an equal vote on regulatory matters. To avoid any undue political influence or pressure, no more than three commissioners may belong to the same political party.

Various energy acts, over time, have increased FERC's responsibilities. Its legal authority comes from the Federal Power Act of 1935 (FPA), the Natural Gas Act (NGA) of 1938, the Natural Gas Act (NGPA) of 1978, the Public Utility Regulatory Policies Act (PURPA) of 1978, the Energy Policy Act (EPAct02) of 1992, and the Energy Policy Act (EPAct05) of 2005.

Five of its offices directly impact the electric power industry:[181]

- Office of Electric Reliability
- Office of Energy Market Regulation
- Office of Energy Projects
- Office of Energy Policy
- Office of Enforcement

Presently, among other responsibilities, FERC

- Regulates the transmission and wholesale sales of electricity in interstate commerce
- Licenses and inspects private, municipal, and state hydroelectric projects
- Ensures the reliability of high-voltage interstate transmission systems
- Monitors and investigates energy markets
- Uses civil penalties and other means against energy organizations and individuals who violate FERC rules in the energy markets
- Oversees environmental matters related to natural gas and hydroelectricity projects and major electricity policy initiatives
- Administers accounting and financial reporting regulations and conduct of regulated companies[182]

[181]The organizational structure of Federal agencies often change as new administrations come into office with new or different agendas.

[182]As part of its responsibilities, especially after the Public Utility Holding Company Act was repealed, is to determine whether mergers and corporate applications are consistent with the public interest. It examines merger effects on competition, rates, and regulation, and the potential for cross-subsidization.

Alternately, FERC does not

- Regulate retail electricity sales to consumers; this is a responsibility of the states
- Approve the physical construction of electric generation, transmission, or distribution facilities, except for hydropower and certain electric transmission facilities located in national interest electric transmission corridors
- Regulate activities of the municipal power systems, federal power marketing agencies like the Tennessee Valley Authority, and most rural electric cooperatives
- Regulate nuclear power plants; this is a responsibility of the Nuclear Regulatory Commission

However, FERC-allowed wholesale power prices must be passed through to retail customers and cannot be challenged by the states. A major part of recent large increases in retail sales were the result of wholesale price increases.[183]

Environmental Protection Agency (EPA)[184]

The EPA was established in July 1970 in response to the growing public demand for cleaner water, air, and land. Its mission "is to protect human health and to safeguard the national environment—air, water, and land—upon which life depends."

In part, "EPA's purpose is to ensure that environmental protection is an integral consideration of U.S. policies concerning natural resources, human health, economic growth, *energy* (emphasis added), transportation, agriculture, industry, and international trade, and these factors are similarly considered in establishing environmental policy."

EPA is charged with administering all or parts of a number of laws.[185] Provisions in many of these laws impact the utility industry from high-profile issues such as rules governing emissions from coal burning power plants to less well-known ones such as allowable herbicides to use to maintain growth on transmission line ROWs.

[183] See *Tejas Power v. FERC,* D.C. Cir. 1990.
[184] The material in this section is from the EPA's website: www.epa.gov.
[185] Links to information on each of these laws can be found at http://www.epa.gov/lawsregs/laws/index.html.

EPA focuses on three main areas regarding NEPA compliance:

1. Coordinating review of all environmental impact statements (EISs) prepared by other federal agencies
2. Maintaining a national EIS filing system and publishing weekly notices of EISs available for review and summaries of EPA's comments
3. Assuring that EPA's own actions comply with NEPA and other environmental requirements

EPA has established air emission regulations for boilers associated with steam generating units. A particularly contentious issue has been the regulations relating to emissions from coal-fired power plants. Among the issues are the pollutants to be regulated and whether older existing plants have to retrofit to meet new standards. See Chapter 16 for a discussion of this topic and recent EPA regulatory activity.

Department of Energy (DOE)[186]

Department of Energy's mission, in part, is to "advance the national, economic, and energy security of the United States; to promote scientific and technological innovation in support of that mission; . . ."

The DOE is principally a national security agency and all of its missions flow from this core mission to support national security. There are three undersecretaries reporting to the Secretary of Energy:

1. Nuclear Security
2. Energy
3. Science

Reporting to these undersecretaries are the following Program Offices:

- Office of Civilian Radioactive Waste Management—manages and disposes of high-level radioactive waste and spent nuclear fuel in a manner that protects health, safety, and the environ-

[186]The material in this section is from the DOE's website: www.doe.gov.

ment; enhances national and energy security; and merits public confidence
- Office of Electricity Delivery and Energy Reliability—leads national efforts to modernize the electric grid, enhance the security and reliability of the energy infrastructure, and facilitate recovery from disruptions to the energy supply
- Office of Energy Efficiency and Renewable Energy—works to provide a prosperous future in which energy is clean, abundant, reliable, and affordable
- Office of Environmental Management—works to mitigate the risks and hazards posed by the legacy of nuclear weapons production and research
- Office of Fossil Energy—works to ensure that reliable, clean, and affordable energy from traditional fuel resources is available
- Office of Legacy Management (LM)—manages the Department's postclosure responsibilities and ensures the future protection of human health and the environment
- Office of Nuclear Energy—supports the nation's diverse nuclear energy programs
- Office of Science—is the single largest supporter of basic research in the physical sciences in the United States, providing more than 40% of total funding for this vital area of national importance

The Department's strategy vis-à-vis the electric power industry, in part, includes efforts to:

- "Diversify America's energy supply by:
  - Promoting alternative and renewable sources of energy
  - Encouraging the expansion of nuclear energy in a safe and secure manner
  - Increasing domestic production of conventional fuels
  - Investing in science and technology
- Increase energy efficiency and conservation in homes and businesses
- Modernize the electric power infrastructure[187]

In addition to its core Offices, the DOE has oversight of the Energy Information Agency, and the Southeastern, Southwestern,

[187]On the Road to Energy Security—Implementing a Comprehensive Energy Strategy: A Status Report, http://www.energy.gov/about/EPAct.htm.

and Western Area Power Marketing Administrations, as well as the Bonneville Power Administration.

The DOE also maintains a number of national laboratories and technology centers, including the Argonne National Laboratory, the Brookhaven National Laboratory, Lawrence Berkeley National Energy Technology Laboratory, and the National Renewable Energy Laboratory.[188]

The mission of the Department with respect to the electric utility industry draws much of its direction from EPAct05, the Independence and Energy Security Act of 2007, and the 2009 ARRAct.

As part of its mission, the DOE has sponsored studies relating to the electric utility industry in a restructured environment.[189] Many experts consider these studies inadequate for setting future national policies.

Nuclear Regulatory Commission (NRC)[190]

The Atomic Energy Commission was created in 1946 to run and oversee all atomic programs. The Energy Reorganization Act of 1974 created the NRC, which began operations on January 19, 1975 and effectively dismantled the 1946 legislation. [191]

The NRC is headed by a five-member Commission. The President designates one member to serve as Chairman and official spokesperson. The Commission as a whole formulates policies and regulations governing nuclear reactor and materials safety, issues orders to licensees, and adjudicates legal matters brought before it. The Executive Director for Operations (EDO) carries out the policies and decisions of the Commission and directs the activities of the program offices.

The offices reporting to the EDO ensure that the commercial

[188]See www.energy.gov/organization/labs-techcenters.htm.

[189]"Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability September 29, 1998"; "The National Transmission Grid Study, U.S. Department of Energy May 2002," www.p.i.energy.gov/ducuments/TransmissionGrid.pdf.

[190]Information obtained at NRC website: http://www.nrc.gov/about-nrc/organization.html.

[191]By the mid-1970s, Congressional hearings resulted in Congress abolishing the AEC and reorganizing it to split the promotional and regulatory functions. The Nuclear Regulatory Commission was created to assume regulatory oversight, while the Energy Research and Development Administration, later to be integrated into the U.S. Department of Energy, took over the promotional function.

use of nuclear materials in the United States is safely conducted. As part of the regulatory process, the four regional offices conduct inspection, enforcement, and emergency response programs for licensees within their borders.

The NRC's regulatory activities are focused on reactor safety oversight and reactor license renewal of existing plants, materials safety oversight and materials licensing for a variety of purposes, and waste management of both high-level waste and low-level waste. In addition, the NRC is preparing to evaluate new applications for nuclear plants. In 2007, some utilities submitted applications for licenses to build new power reactors, which had not occurred since the late 1970s.

Recent Federal Regulations

Legislation establishes the basic policies for electric power but implementation of these policies is the responsibility of the various regulatory agencies. Although previously cited agencies play a role in the regulation of the electric power industry, FERC plays the most important role.

Over the period 1993–2008, FERC has issued numerous Rules and Orders. In some ways, it has been a learning process requiring modifications of initial orders as lessons are learned as the process has evolved. A review of these key FERC decisions and procedures is essential to understanding the functioning of the electric power industry. The following covers FERC's actions with respect to Epact92 and EPAct05.

FERC Actions after EPAct92

The requirements of EPAct92 gave FERC additional authority to order transmission as well as exempting certain wholesale generations from PUHCA, but not from the FPA.

Orders 888/889—Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities). FERC issued Orders No. 888 and No. 889 in April 1996, intending "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers." Further, they were to ". . . remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." These orders had three goals:

1. Promotion of wholesale competition through open-access, nondiscriminatory transmission services by public utilities
2. Recovery by public utilities and transmitting utilities of stranded costs
3. Establishment of an open-access, same-time information system and standards of conduct

All public utilities that owned, controlled, or operated facilities used for transmitting electric energy in interstate commerce had

- To file open-access nondiscriminatory transmission tariffs (OATT) that contain minimum terms and conditions of nondiscriminatory service[192]
- To take transmissions service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open-access tariffs
- To develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys (OASIS)
- To separate transmission from wholesale power service functions (functional unbundling instead of the more draconian step of corporate unbundling), meaning that they:
  - Take wholesale transmission services under the same tariff of general applicability as they offer their customers
  - State separate rates for wholesale generators, transmission, and ancillary services
  - Rely on the same electronic information network that their transmission customers rely on to obtain information about the utilities' transmission systems.

The order also:

- Clarified Federal/state jurisdiction over transmission in interstate commerce and local distribution

[192]The order included a pro forma open-access transmission tariff (OATT).

- Identified ancillary services[193] required for the functioning of the transmission system
- Provided guidance regarding the formation of independent system operators (ISOs), which would be subject to FERC's authority

FERC suggested the concept of an independent system operator as one way for existing tight power pools to satisfy the requirement of providing nondiscriminatory access to transmission.

Eleven principles for ISOs were identified to insure that the operation of the transmission system would not favor the utility owners. ISOs must:

- Be structured in a fair and nondiscriminatory manner
- Have no financial interests in any market participant (neither the ISO nor its employees)
- Provide open access at nonpancaked rates, that is, a single unbundled grid-wide tariff
- Have primary responsibility for the short-term reliability of the grid by complying with NERC and regional standards
- Have control over the operation of the interconnected transmission facilities
- Identify constraints on the transmission system and take operational actions to relieve them
- Have pricing policies for transmission and ancillary services that promote efficient use of investments in generation and transmission
- Have incentives for procuring efficient management and administration in the market
- Develop mechanisms to coordinate with their neighbors
- Establish an alternate dispute-resolution process
- Make transmission system information publicly available (OASIS)

Order No. 2000—Regional Transmission Organizations. In December 1999, FERC issued Order 2000, wherein it encouraged the voluntary formation of regional transmission organizations (RTOs) to administer the transmission grid on a regional basis throughout

[193]See Chapter 8 for a list of ancillary services.

North America (including Canada). This step expanded on the role of an ISO by adding additional responsibilities, including that of planning for transmission system expansion. FERC stated that "continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding full competitive electricity markets" and that its "goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service." To address this concern, FERC took its next step in defining its requirements for an independent transmission provider. It required "... that each public utility that owns, operates, or controls facilities with the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO." It

- Established minimum characteristics and functions for RTOs
- Stated it would sponsor a collaborative process by which public utilities and nonpublic utilities that own, operate, or control interstate transmission facilities may form or join RTOs in consultation with state officials as appropriate
- Gave a time line for public utilities to make filings to initiate operation of RTOs

FERC specified four minimum characteristics and eight functions of an RTO. To some extent these mirrored the eleven principles specified for ISOs. They differed in that the RTO material included provisions for planning and expansion and for management of congestion and parallel path flow.

Minimum characteristics are:

- Independence
- Scope and regional configuration
- Operational authority
- Short-term reliability

Functions are:

- Tariff administration and design
- Congestion management
- Parallel-path flow management
- Ancillary services

- OASIS, total transmission capability (TTC), and available transmission capability (ATC)
- Market monitoring
- Planning and expansion of the transmission system
- Interregional coordination of reliability and market issues

Order 890—Amendments to Orders 888 and 889. In February 2007, FERC amended its regulations, issued in Orders 888 and 889, in order "to remedy increasing transmission congestion on a nondiscriminatory basis. . . ." It concluded "that transmission providers have a disincentive to remedy increasing transmission congestion on a nondiscriminatory basis and that the current pro forma OATT does not adequately address this problem."

The purposes of its ruling were

- To strengthen the pro forma OATT to ensure that it achieves its original purpose of remedying undue discrimination
- To provide greater specificity in the pro forma OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the Commission's enforcement
- To increase transparency in the rules applicable to planning and use of the transmission system

The final rule required that

- Transmission providers participate in a coordinated, open, and transparent planning process on both a local and regional level
- Each transmission provider's planning process meet the Commission's nine planning principles, which are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation (for new projects)
- Each transmission provider must describe its planning process in its tariff; the Commission will allow regional differences in planning processes

Also included among its reforms, the order required greater consistency and transparency in ATC calculation and reform of the methods to price differences between scheduled and actual delivery of energy.

FERC Actions Implementing EPAct05

EPAct05 resulted in a number of FERC orders impacting the planning and operation of the bulk power system.

Market Manipulation

EPAct05 gave FERC the authority to issue rules to prevent market manipulation in jurisdictional wholesale power and gas markets and in jurisdictional transmission and transportation services. FERC's Office of Enforcement has this responsibility.

Order 670—Anti-Manipulation/Anti-fraud. On January 19, 2006, the Commission established new anti-manipulation rules under which it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or natural gas, or the purchase or sale of transmission or transportation services subject to Commission jurisdiction

- To defraud using any device, scheme or artifice (i.e., intentional or reckless conduct)
- To make any untrue statement of material fact or omit a material fact
- To engage in any act, practice, or course of business that operates or would operate as a fraud or deceit

Electricity Reliability and Infrastructure

To implement its authority to oversee mandatory reliability standards governing the nation's electricity grid, it finalized rules on the certification of an Electric Reliability Organization (ERO) and on procedures for the establishment, approval, and enforcement of mandatory electric reliability standards. FERC has now certified NERC as the ERO.

Order No. 672—Electricity Reliability and Infrastructure. On February 3, 2006, FERC issued Order No. 672 establishing the procedures for the formation and functions of the Electric Reliability Organization (ERO) and Regional Entities. It established rules on procedures for the establishment, approval, and enforcement of mandatory electric reliability standards. There have been subsequent orders clarifying and amending some conditions of the initial order.[194,195] NERC applied for and was granted the role of ERO by FERC in June 2007. NERC set up as a self-regulatory organization, subject to oversight by the FERC and governmental authorities in Canada.

The initial order addressed the following issues:

> Under the new electric power reliability system enacted by the Congress, the United States will no longer rely on voluntary compliance by participants in the electric industry with industry reliability requirements for operating and planning the Bulk-Power System. Congress directed the development of mandatory, Commission-approved, enforceable electricity reliability standards.
>
> The Commission will certify a single Electric Reliability Organization (the ERO) to oversee the reliability of the United States' portion of the interconnected North American Bulk-Power System, subject to Commission oversight. The ERO will be responsible for developing and enforcing the mandatory reliability standards.
>
> The Reliability Standards will apply to all users, owners and operators of the Bulk- Power System. The Commission has the authority to approve all ERO actions, to order the ERO to carry out its responsibilities under these new statutory provisions, and also may independently enforce Reliability Standards.
>
> The ERO may delegate its enforcement responsibilities to a Regional Entity. . . . A Regional Entity may also propose a Reliability Standard to the ERO for submission to the Commission for approval. This Reliability Standard may be either for application to the entire interconnected Bulk-Power System or for application only within its own region.
>
> The ERO or a Regional Entity must monitor compliance with the Reliability Standards. It may direct a user, owner or operator of the Bulk-Power System that violates a Reliability Standard to comply with the Reliability Standard. The ERO or Regional Entity may impose a penalty on a user, owner or operator for violating a Reliability Standard, subject to review by, and appeal to, the Commission.

[194]A source of documents on Order 672 can be found at: http://www.balch.com/erl/blog.aspx?entry=34.

[195]FERC's summary of Order 672 can be found at: http://www.ferc.gov/industries/electric/indus-act/reliability/E-1-overview.pdf.

As required by its status as the ERO and FERC's Orders implementing EPAct05, NERC filed its Standards with FERC for approval on April 4, 2006.

Order 693—Approval of Reliability Standards.[196] FERC in March 2007 approved 83 of 107 Reliability Standards proposed by NERC, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards. However, FERC noted that "significant improvements" were needed in 56 of the 83. FERC required additional information on the 24 standards not approved.[197] In its comments on the standards, FERC did not deal with technical issues but rather focused on ensuring that each standard included a way of measuring compliance, that it identified a responsible party, and that a measure of the severity of noncompliance was included.

In April 2007, FERC approved eight regional delegation agreements to provide for development of new or modified standards and enforcement of approved standards by Regional Entities.

Subsequent orders approved additional standards:

- December 2007, Order 705—three reliability standards concerning facilities design, connections, and maintenance[198]
- January 2008, Order 706—eight standards for critical infrastructure protections applying to critical cyber assets, which are defined as programmable electronic devices and communication networks, including hardware, software, and data[199]
- July 2008, Order 713—a modification of five of the reliability standards, approved in 2007, relating to interchange scheduling and coordination. This was the first time FERC acted to modify and strengthen reliability standards first approved in Order No. 693.[200]
- October 2008, Order No. 716—a standard for nuclear plant interface coordination[201]

[196]http://www.ferc.gov/whats-new/comm-meet/2007/031507/E-13.pdf.
[197]A glossary of terms used in NERC's standards can be found at http://www.nerc.com/page.php?cid=2|20.
[198]http://www.ferc.gov/industries/electric/indus-act/reliability.asp.
[199]http://www.ferc.gov/industries/electric/indus-act/reliability.asp.
[200]http://www.ferc.gov/whats-new/comm-meet/2007/031507/E-13.pdf.
[201]http://www.ferc.gov/industries/electric/indus-act/reliability.asp. Also see Chapter 15.

Standards development and FERC approval is still a work in progress. Current status of all standards can be found at the NERC website, www.nerc.org.

Expansion and Modernization of the Nation's Electricity Grid

Order 679—Promoting Transmission Investment. This rule contains electric transmission pricing reforms designed to promote investments in energy infrastructure, specifically those that improve regional reliability and reduce transmission congestion. Special consideration is given to transcos and for utilities that join a transmission organization (ISO or RTO). The reforms include:

- Provision of a rate of return on equity (ROE), within the zone of reasonableness, that is sufficient to attract new investment in transmission facilities
- Recovery of 100% of prudently incurred transmission-related construction work in progress (CWIP) in the rate base
- Recovery of prudently incurred precommercial operations costs by expensing these costs instead of capitalizing them
- Adoption of a hypothetical capital structure allowing more flexibility in financing
- Acceleration of the recovery of depreciation expense
- Recovery of all prudently incurred development costs in cases in which construction of facilities may subsequently be abandoned as a result of factors beyond the public utility's control
- Provision of deferred cost recovery
- Any other incentives approved by FERC that are determined to be just and reasonable, and not unduly discriminatory or preferential

Order 681—Long-Term Transmission Rights. This rule requires transmission organizations with organized electricity markets to make available to load-serving entities long-term firm transmission rights that satisfy certain guidelines to help customers who want to make long-term supply arrangements.

Siting Major New Transmission Facilities

Responding to concerns that state regulators had veto power over proposed interregional transmission lines, the Secretary of Energy was empowered to designate "national interest electric transmission corridors" where there is major transmission congestion. Applicants seeking to build transmission within these corridors can seek construction permits from FERC under certain conditions. FERC signed a Memorandum of Understanding with the Department of Energy and other federal agencies with authority to issue federal authorizations for electric transmission facilities to establish a coordinated federal review and permitting process that continues strong federal environmental protections.

Order 689—Siting of Electric Transmission. FERC has established rules on transmission siting that will govern the issuance of construction permits.

PURPA Reforms

Orders 671 and 671A—Qualifying Facilities. FERC tightened the thermal efficiency requirements for qualifying cogeneration facilities under PURPA. These rules are intended to limit the potential for abuse under PURPA, curtail sham transactions, and prevent new PURPA "machines." At the same time, the rules support the development of new cogeneration facilities that truly conserve energy, by ensuring that new qualifying cogeneration facilities use thermal output in a productive and beneficial manner, and that the electrical, thermal, chemical, or mechanical output of new qualifying cogeneration facilities is used fundamentally for industrial, commercial, or institutional purposes.

Order 688—PURPA Small Power Production. FERC eliminated ownership restrictions on qualifying cogeneration and small power production facilities. These restrictions had limited the percentage of QFs that utilities could own since it might be inappropriate for utilities to be on both sides of the table when negotiating "avoided costs."

Repeal of PUHCA—Mergers and Acquisitions

FERC implemented the repeal of PUHCA 1935 and the provisions of a new PUHCA 2005. PUHCA 2005 permits Commission access to books and records of holding companies and their members if necessary for determining jurisdictional rates. The Commission implemented PUHCA rules governing accounting, record retention, and reporting, including certain blanket waivers and exemptions, within the deadlines in EPAct05.[202] Along with the repeal of PUHCA 1935, EPAct05 expanded the Commission's corporate review authority to include authority over certain holding company mergers and acquisitions, as well as certain public utility acquisitions of generating facilities. It also imposed statutory deadlines for acting on mergers and other jurisdictional corporate transactions.

Market-Based Rates

FERC has also addressed issues relating to the establishment of market based rates for generation.

Order 697—Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities. FERC in this order issued on June 21, 2007 indicated that its objective was to ensure that market-based rates charged by public utilities are just and reasonable. It addressed three major aspects of the Commission's market-based rate regulatory regime:

1. Whether a market-based rate seller or any of its affiliates has market power in generation or transmission and, if so, whether such market power has been mitigated. If the seller is granted market-based rates, the authorization is conditioned on affiliate restrictions governing transactions and conduct between power sales affiliates when one or more of those affiliates has captive customers.
2. Those wholesale sellers that have market-based rate authority and sell into day-ahead or real-time organized markets administered by RTOs and ISOs are subject to specific RTO/ISO market rules approved by FERC and applicable to all market participants.

[202]The Government Accountability Office (GAO) issued a report regarding how FERC was implementing its responsibilities. This report stated "FERC continues to rely to a considerable degree on companies to self-certify that they will not cross-subsidize and to report when they do." The report also points out that the repeal of PUHCA has made regulation more difficult (GAO-08-789 Utility Oversight, February 2008).

3. FERC, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates. FERC may institute a Section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization.

The order addressed issues relating to horizontal and vertical market power and affiliate abuses.

In response to comments challenging its authority to allow market-based rates without prior review, the order contained a lengthy section justifying the legal basis for FERCs authority.[203]

Order 719—Wholesale Competition in Regions with Organized Electric Markets. In this order, issued on October 17, 2008, FERC addressed:

- Demand response and market pricing during periods of operating reserve shortage
- Long-term power contracting
- Market-monitoring policies
- The responsiveness of RTOs and ISOs to their customers and other stakeholders, and, ultimately, to the consumers who benefit from and pay for electricity services

This order was addressed solely to established RTOs and ISOs.

Recent EPA Actions

The extent of the authority of the EPA to regulate emissions from power plants has been hotly debated and litigated in recent years. See Chapter 16 for a discussion of recent EPA actions relating to the fuels used by the electric power industry. The recent election of President Obama signals a more aggressive stance towards utility-related environmental issues, especially the emissions of greenhouse-related gases.

[203]See Section G. Legal Authority: 1—Whether Market-Based Rates Can Satisfy the Just and Reasonable Standard Under the FPA Consistency of Market-based Rate Program with FPA Filing Requirements; and 2—Whether Existing Tariffs Must Be Found to Be Unjust and Unreasonable, and Whether the Commission Must Establish a Refund Effective Date.

State Regulatory Authority

All states regulate the retail rates and tariffs of investor-owned utilities (IOUs). These rates and tariffs cover all of the charges a customer will see in his/her bill except for those charges for services under FERC jurisdiction, that is, charges for wholesale energy purchases (although state commissions might approve contracts beforehand) and charges for transmission service to deliver the wholesale energy.

Generally, the regulating authority is called a Public Service Commission or a Public Utilities Commission.[204] Some states regulate the rates and tariffs charged by municipal and cooperative utilities, generally on a more limited basis than for IOUs. Municipal utilities are an aspect of local government and the fact that the local electorate can exercise control over the policies of the municipal utility by its voting privileges is considered generally to be an effective form of regulation not requiring further supervision by a state agency. The customers of cooperative utilities are its direct owners and direct the activities of the utility by their vote.

Even so, a number of states in varying degree allow their regulating agency to supervise the rates and tariffs of municipal and cooperative utilities. In 20 states, the regulatory authority has at least limited jurisdiction over the rates of municipal utilities; in 30 states, the regulation of rates by the state agency extends to cooperatives. As noted earlier, oversight of many federal environmental regulations was given to the individual states.

In addition to regulation of rates and tariffs, states also regulate the construction of electric transmission facilities. Many states require utilities to demonstrate the need for new transmission facilities and that they will be built in a way to minimize environmental impacts. Because this approval authority gives individual states veto power over multistate transmission projects, EPAct05 contains a provision that allows appeal to FERC for approval in cases in which states have not acted within specified time limits if the projects are intended to relieve congestion in DOE-specified "national interest" corridors.

An ongoing governance issue is the boundary of responsibility between Federal and state regulators.

[204]A link to each of the state utility commissions can be found at the NARUC website, www.naruc.org.

*Tariff Basis.*A key FERC requirement is that transmission systems must be open to all potential users on a nondiscriminatory basis. This involves the rights to use the facilities and the tariffs to be charged. It requires that all others can also use a transmission system built to supply a specific group of consumers on the same basis as the original users.

A major item following the initial orders for open transmission access was the return that should be allowed on transmission investments, with transmission owners and potential transmission investors considering the past rates of return on investment proposed by FERC to be too low to provide needed earnings and to justify the significant additional investment that is required. As noted above, FERC addressed this concern in Order 679.

Transmission Rights. Transmission rights define property rights and not only entitle market participants to the financial benefits associated with the use of a transmission system, but also encourage investment in transmission infrastructure by providing a commodity that is fixed in nature and can be traded in an open market.

There are two types of transmission rights: physical transmission rights ("PTRs") and financial transmission rights ("FTRs"). See Chapter 18 for a discussion of these rights.

State Utility Restructuring

State activities in requiring or pressuring their utilities to restructure tended to mirror the relative cost of electricity in their states. States with higher costs generally implemented more aggressive restructuring, over and above what FERC required, than those with lower costs.

The experience in California in the early 2000s and recent (2006–2008) rate increases occurring in states, where rate freeze agreements entered into as parts of restructuring agreements have ended, severely reduced the popularity of state restructuring activities. State restructuring activities included:

- Some form of immediate rate reduction and freezing for a specified period thereafter with provision for stranded cost recovery
- Mandated or encouraged generation plant divestiture
- Requirements for retail access

Customer Choice. A major advantage claimed for state-level restructuring is the provision of customer choice. Customers would have the ability to decide which companies would provide their electric power. Theoretically, this competition might lead to lower electricity prices. The existing distribution system would continue to deliver the power and would continue to be regulated. In general, a very small percentage of the customers having the ability to choose another power supplier have used it. Of those that have switched, the majority have been industrial and large commercial customers.

Metering. Customer choice has required significant additional metering expenses so that the data required for the billing of supplies to many consumers having different suppliers could be handled. It has also become necessary to meter use over precise time frames to accommodate new usage rates. The sophistication and cost of new meters and communication equipment to customer premises are important considerations when considering implementation of many Smart Grid proposals.

Distribution Rates. In the past, the distribution system component of rates was based on a predetermined return on equity that reflected imbedded investment costs and actual operating costs. This procedure is being continued. However, increased attention is being placed on including a measure of performance in the rate structure, that is, rates that can be adjusted up or down depending on the quality and reliability of service, and the overall response to customer needs.

State and Local Environmental Requirements. State and local laws cover a number of environmental and safety matters. Local communities often must issue building permits. These requirements can make very difficult the ability to build transmission facilities. Under various Federal environmental laws, state authorities have been given responsibility for ensuring utility compliance. With regard to as transmission line approvals, many states require examination of environmental compatibility as well as public need prior to approving new transmission lines.

Overall Regulatory Problems

The legislative and regulatory networks discussed above are obviously complex and often create problems because of:

- Lack of understanding by regulators and legislators of the technical and economic functioning of electric power systems
- Conflicts between states and the federal government over policy and authority
- Conflicting regulatory priorities, that is, environmental concerns versus the requirement of low-priced electricity

Many believe that we need far greater coordination between our legislation, regulation, and power system technology, as well as competent regulators not committed to any group concerned with profits instead of the public welfare.

CHAPTER 15

THE INFORMATION, COMMUNICATION, AND CONTROL NETWORK AND SECURITY

This network is an extensive system impacting the physical, energy, money, business, and regulatory networks. It includes all mechanisms and processes for obtaining information, transmitting this information to some location where it is analyzed and decisions made as necessary, and then the communication of the decisions so they can be acted upon.

This network is not static in time. We have discussed some of the technology improvements and innovations being implemented in the physical network. Similarly, the information, communications, and control network is also experiencing similar changes.

The utility industry has been affected, as have many others, by the widespread use of the Internet, communication networks capable of transmitting large quantities of information very quickly, and computer-based sensing and computing equipment based on microprocessor technology. These developments have allowed improvements in many areas of business, such as in reliability, productivity, and speed of response.

15.1 SMART GRID

As discussed in Chapter 8, a major effort is underway in the United States, driven in large part by the Energy Independence and Security Act of 2007, to develop a "Smart Grid." In a December 2008

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report issued by the DOE's Electricity Advisory Committee entitled "Smart Grid: Enabler of the New Energy Technology," a Smart Grid is defined as a "broad range of solutions that optimize the energy value chain." The report refers to economic, environmental, reliability, and security objectives. The effort makes use of technical advances in sensing devices, communications capabilities, and computational capabilities, both distributed and centralized. One aspect of the development is the improvements made in so called "legacy" computer systems internal to the utilities. In many cases, these systems were characterized by stand-alone databases containing information that, if properly combined, would be of great benefit to the company.

In the following material, we will mention some, but by no means all, of the components of this network.

15.2 FINANCIAL AND BUSINESS OPERATIONS

The introduction of advanced financial management systems allows managers to better understand the cost drivers of their business and business segments and to deal with the increasing complexity of the utility business structure, especially on the holding company level. For example, interrelationships of electric trading strategies, purchasing decisions, and outsourcing strategies can all be examined.

Computer technology and the Internet have had a major impact on the way companies do business. The terms E-business and E-commerce are used to describe a wide spectrum of applications that allow the utility to exchange information with its customers, its suppliers, its regulators, and the energy market:

- The Internet-based OASIS system is at the heart of the wholesale energy market
- Internet-based material and services procurement arrangements with suppliers eliminate processes that added to the time and cost of obtaining these services
- Customers can now pay their bills online
- Customer contact has been improved by the establishment of customer call centers operated 24 hours a day
- Online filing of documents with the SEC and other regulatory agencies

The OASIS system is a good example of the interconnectivity of the various networks. For example, it deals with the physical security of the transmission system as well as the financial system since it deals with the submission of bids for various generation-related products and services.

15.3 SYSTEM OPERATIONS

A measurement and communication network has been used for years by the industry to measure and transmit, to a central control point, information about the physical state of the power system (voltages, currents, breaker and relay status, generator output, etc.). The network is also used to transmit operational orders to substations and to generating stations.

Programs underway address both the distribution and the bulk power transmission systems:

- In recent years high-speed communication links and online state estimation[205] have been implemented.
- Computer programs are being developed to dynamically analyze the optimum settings of FACTS and other control devices to increase the reliability and power transfer capability of the transmission system on a real-time basis.
- Some areas are installing wide-area measurement systems (WAMS) using satellite-based communications to give operators a more comprehensive view of the electrical status of the grid.

15.4 DISTRIBUTION OPERATIONS

Significant strides have been made in the ability to automate the operation and reduce the costs associated with the distribution system. Many of the benefits were listed in Chapter 7. Among these are:

[205]The use of telemetered values to rapidly determine the electrical status at all points on the transmission system and to suggest remedial actions in case of emergencies.

- Work management systems (WMS) used for optimizing work scheduling and dispatching of work orders to field crews[206]
- Improvements, using microprocessors, in SCADA systems for remote monitoring and control of the status of the distribution system, such as line loadings, circuit breaker status, and voltages to a central operations center
- Geographic information systems (GIS)[207] which relate customers to specific geographic locations
- Outage management systems (OMS) to handle the large amount of information relating to system outages, especially outages impacting many customers due to ice storms, tornadoes, and so on, and the efficient dispatching of crews for restoration purposes
- Asset management systems (AMS) which are used to schedule maintenance
- Automated meter reading (AMR)

Some utilities are combining aspects of these systems to create a more robust tool. For example, integrating a GIS system with an OMS system, and using information from 24 hour call centers and from the customer information system (CIS) provides additional information which can shorten restoration times.

15.5 CYBER SECURITY

Cyber security has two aspects:

1. Market security concerns the ability to avoid market manipulation or disruption by individuals who illegally gain access to its communication or computer systems.

[206]Information on WMS can be found in the January 2003 issue of "Utility Automation" for a broader discussion of issues concerning WFM in an article by Scott Munro, "Work Force Management Unifies Field Operations."
[207]Information on GIS systems can be found at the USGS website: www.usgs.gov. The following was excerpted from that website: "In the strictest sense, a GIS is a computer system capable of assembling, storing, manipulating, and displaying geographically referenced information, i.e. data identified according to their locations. Practitioners also regard the total GIS as including operating personnel and the data that go into the system." "The way maps and other data have been stored or filed as layers of information in a GIS makes it possible to perform complex analyses."

2. Operational security concerns the ability of the communication and control systems to avoid manipulation by those seeking to cause power outages.

FERC has focused its attention on the first aspect ever since it initiated its efforts on restructuring the industry. Experience in California has shown that great sums of money can be made by exercising various forms of market power or by violating market rules. It is for this reason that FERC proposed a market monitoring function in its SMD NOPR.

The second aspect is one of the focuses of the nation's response to terrorist threats. As we have discussed earlier, the electric system is designed to withstand various disturbances and to rapidly restore service in the event of outages. In addition to the physical assets, attention is also focused on the SCADA systems used for control and communications. Disruption of these systems can have wide-ranging impacts not only on the physical performance of the system (bogus telemetered orders to open many circuit breakers at the same time, resulting in the loss of more facilities than considered in design) but also on commercial operations.

As companies rely more and more on computerizing and networking their systems, especially in their use of the Internet as a communication medium, they make themselves more vulnerable to cyber attack. Efforts to standardize and to use open platforms contribute to this vulnerability. The efforts to combine database information discussed in the Distribution Operations section, illustrate the increased exposure when combinations are implemented.

The literature contains many articles by specialists who address issues such as protocols for access to sensitive information and the technology of building robust firewalls.[208]

The U.S. government has been active in efforts to protect the nation's critical infrastructures, including cyber security. The effort, on a national level, to deal with electric utility security began in 1998 with a Presidential Order issued by President Bill Clinton, "Protecting America's Critical Infrastructures." Electric utilities were one of eight areas identified as critical. In February 2003,

[208]See the "National Strategy to Secure Cyberspace" issued by the White House in February 2003 at www.whitehouse.gov/pcipb/cyberspace_strategy.pdf.

President George W. Bush issued the National Strategy to Secure Cyberspace,[209] which states that:

> Recognizing the increasing danger posed by cyber threats and the devastating disruption that could result because of the interdependent nature of information systems that support our nation's critical infrastructure, the Strategy provides a strategic framework to prevent cyber attacks against America's critical infrastructures; reduce national vulnerability to cyber attacks; and minimize the damage and recovery time from cyber attacks should they occur. The Strategy outlines five national priorities including:
>
> - A National Cyberspace Security Response System;
> - A National Cyberspace Security Threat and Vulnerability Reduction Program;
> - A National Cyberspace Security Awareness and Training Program;
> - Securing Government Cyberspace; and
> - National Security and International Cyberspace Security Cooperation

In response to the Clinton order, the DOE was appointed the lead agency for the electric sector. The DOE appointed NERC as the Sector Coordinator to:

- Assess sector vulnerabilities
- Develop a plan to reduce electric system vulnerabilities
- Propose a system for identifying and averting attacks
- Develop a plan to alert electricity sector participants and appropriate government agencies that an attack is imminent or in progress
- Assist in reconstituting minimum essential electric system capabilities in the aftermath of an attack

Following the attacks on September 11, 2001, NERC developed and issued in 2003 a cyber security standard for the electric industry on a voluntary basis. This standard, Urgent Action 1200, remained in effect until June 2006, at which time it was replaced by eight CIP Reliability Standards (see Table 15-1).

These standards were submitted to FERC and approved in

[209]http://www.dhs.gov/xnews/releases/press_release_0620.shtm.

Table 15-1. NERC Cyber Security Standards

CIP standard Number	Cyber security topic
002	Cyber Asset Identification
003	Security Management
004	Personnel and Training
005	Electronic Security Perimeters
006	Physical Security of Critical Cyber Assets
007	Systems Security Management
008	Incident Report and Response Planning
009	Recovery Plan for Critical Cyber-Assets

FERC Order 706 in January 2008.[210] The order identifies cyber assets as programmable electronic devices and communications networks, including hardware, software, and data.[211]

15.6 NUCLEAR PLANT SECURITY

Nuclear plant security is under the direction and supervision of the NRC. However, in its review and adoption of NERC's reliability standards in Order 706, FERC identified a potential gap in coverage, specifically, the systems within a nuclear plant called *balance of plant.* In September 2008, it issued a directive to NERC to modify its cyber standards to insure that they are applicable, as appropriate, to nuclear plants.

[210]http://www.ferc.gov/whats-new/comm-meet/2008/011708/e-2.pdf.
[211]See www.nerc.com/fileUploads/file/news/Executive-Remarks.110509.pdf for a discussion of NERC's 2009 filing on cyber security with FERC.

CHAPTER **16**

THE FUEL AND ENERGY NETWORK

The third major physical network that is part of the electric power system is the fuel and energy supply network of railroads, pipelines, and barge and truck transport of the fuel needed by the power plants. To this array of transportation systems a network of pipeline or other transport systems to carry carbon dioxide away for storage in geological formations may be added in the future. The fuel-based transportation system often includes various storage or inventories of the fuels. Most electric utilities buy the fuels they use from other companies and have a substantial fuel procurement process. Some companies located near major coal fields have constructed power plants near the coal mines.

In some regions, there are also extensive networks of dams on rivers that provide hydroelectric power. These sources and systems are developed, designed, and operated to meet specific needs. Other, nonfuel energy resources such as geothermal, wind, and sunlight are generally site specific and their ability to provide energy to the system is dependent on the vagaries of nature. Collectively, these nonfuel energy sources are known as renewables.[212]

This network can be diagramed as illustrated in Figures 16-1 and 16-2 from a 1973 report to the U.S. Office of Science and Technology.[213] The effects of fuel policy changes and disruptions

[212]Tidal, wave, and ocean–thermal sources may be developed in the future.

[213]Report to the Office of Science and Technology by Associated Universities Under contract OST-30, 1973. Figure 16-2 shows a projection for the network for 2020. It provides an interesting example of the accuracy of projections made 50 years in advance.

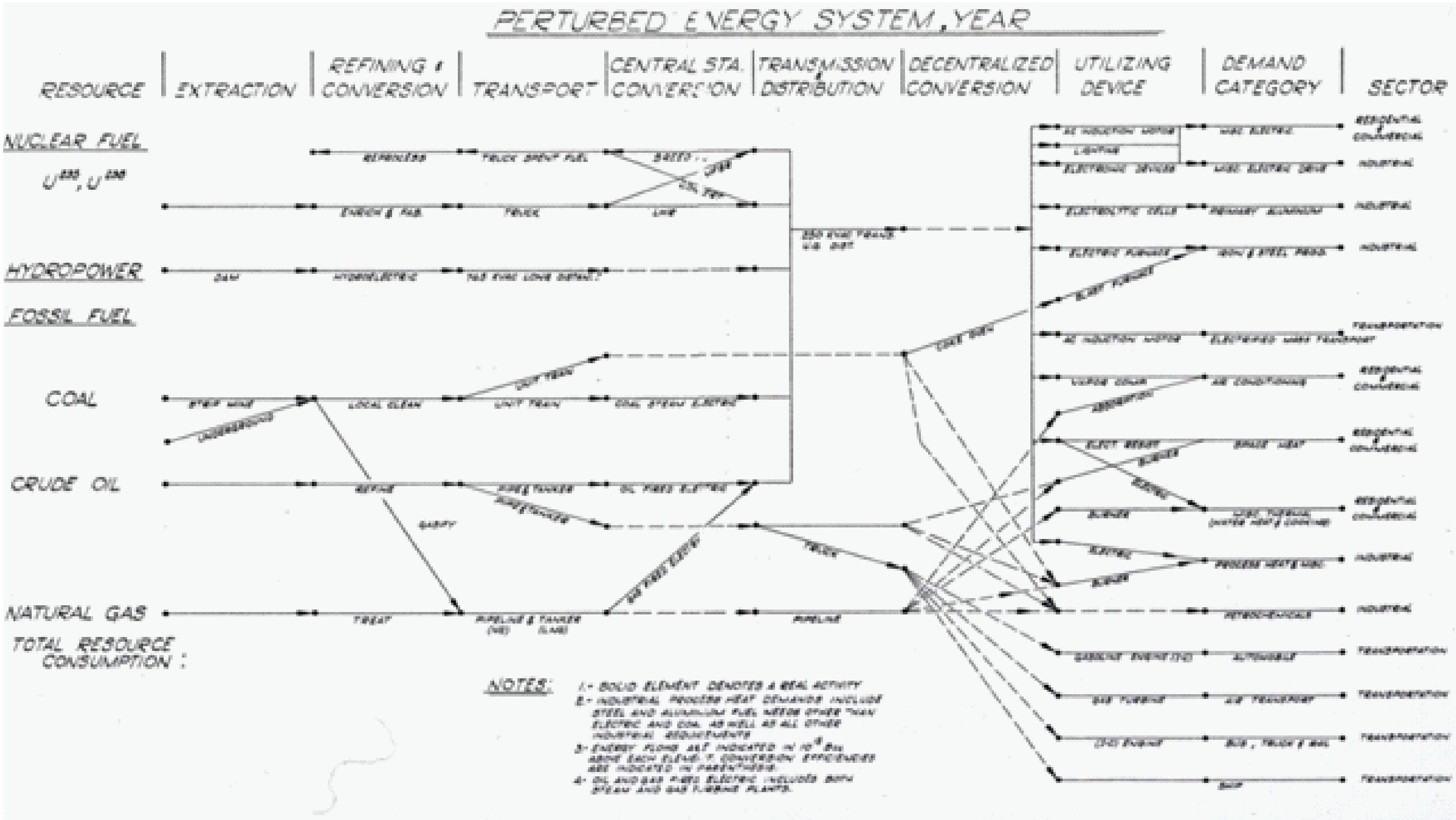

Figure 16-1. Idealized energy flow diagram.

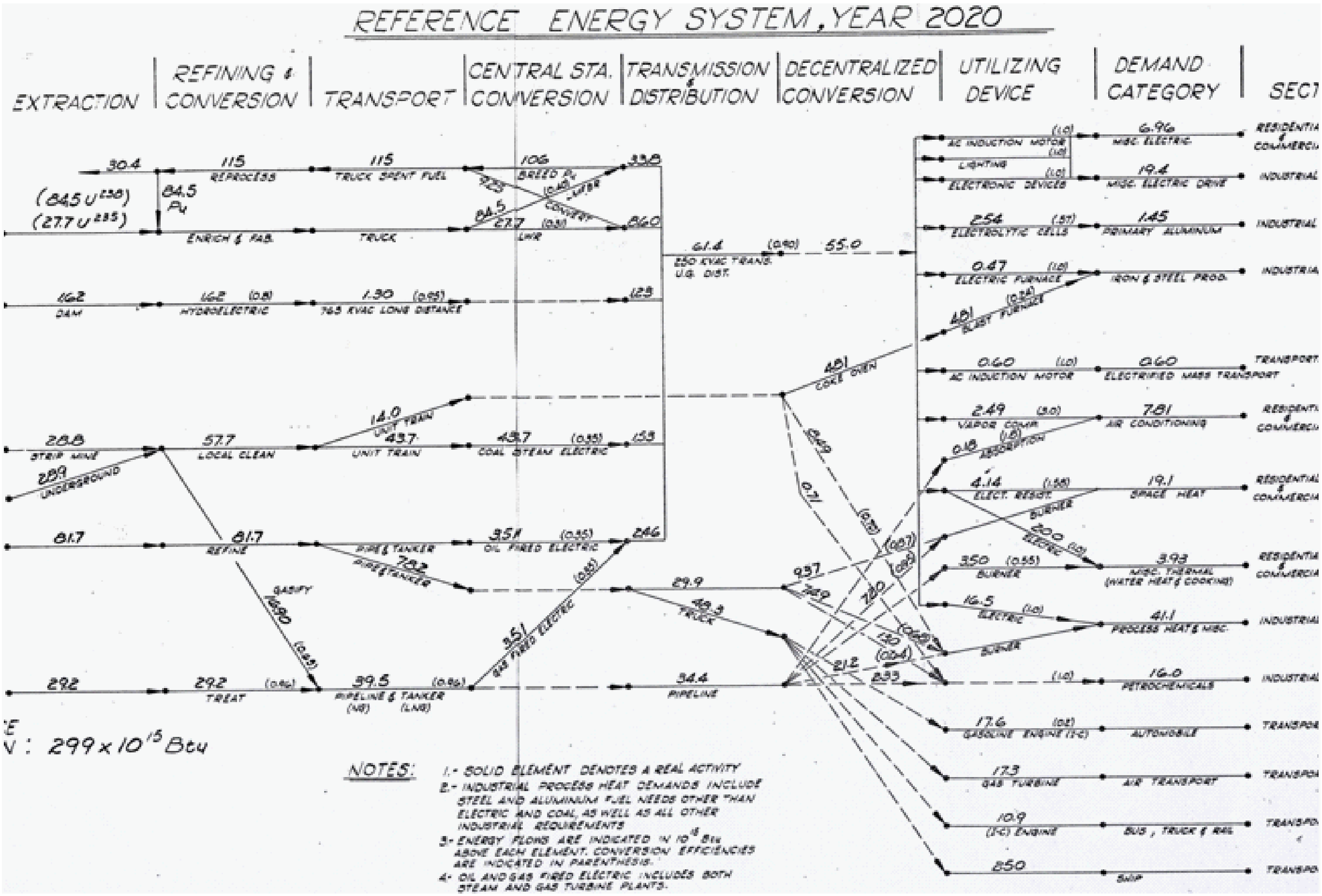

Figure 16-2. Energy flow forecast for 2020 made in early 1970s.

in fuel supplies may be analyzed by perturbing a network using such a diagram.

A new and potentially significant source of energy for the U.S. power system is wind. Presently (2009), the largest installations of wind power projects in the United States are land based and located in the states of California, Texas, and Iowa. In Europe, a significant amount of its wind power comes from offshore developments.[214] See Chapter 8 for more information on wind energy.

16.1 RESOURCE PROCUREMENT

The generation of electricity requires a source of energy that is converted to electricity. The primary energy sources used for the production of electric power are fossil (carbon-based) fuels [coal, natural gas, and petroleum (oil)], nuclear fuel (uranium), and water. Renewables, other than hydroelectric, contributed a small amount (2.5%) of the electric power produced in the United States in 2007, although their rate of growth is robust (29.7% increase in energy supplied between 2002 and 2007).

The physical units used to measure the quantity of carbon-based fuels consumed are tons, barrels, and cubic feet for coal, oil, and natural gas, respectively. The water used in hydroelectric power generation can produce varying amounts of electric power depending on the height or elevation through which it falls, described as its head, which will change as the water level behind the dam changes. Similarly, the raw material used to produce nuclear fuel is known as yellowcake and is measured in tons. One source quotes the fuel required for a 1300 MW unit annually to be about 210 tons of yellowcake.

Carbon-based fuel arrives at generating stations from many different sources and by different modes of transportation. Even within a single utility system, its generating stations are likely to receive fuel from different suppliers and regions of the world. These differences in source of supply and transportation cost contribute to large differences in the delivered price of fuels and their quality.

[214] See IEEE paper on location of wind power, http://www.ieee.org/web/emergingtech/discourses/windpower/windpower_location.html.

Fuel Measurements

One of the primary means of measuring the quality of fuel is to record the amount of heat contained in a given quantity. For fossil fuels (coal, oil, and gas) in the United States, this is usually given in units of BTUs[215] (British Thermal Units) per pound, gallon, or cubic foot. The price paid by a utility for a quantity of fuel is usually keyed to the heat content of a particular shipment. For instance, coal arriving at two different generating stations from two different mines might have heat contents of 10,000 BTU per pound for one and 12,000 BTU per pound for the other. If both shipments were burned in identical generating units, one ton of the 12,000 BTU per pound coal would produce 20% more kilowatt hours of electricity than the 10,000 BTU per pound coal. It is for this reason that fuel prices are often quoted on a cost per BTU basis rather than a cost per ton, barrel, or cubit foot basis.

Other factors affecting the quality of fuels are the amount of other material contained in a given quantity. For coal and oil, most of these impurities are ash and sulfur.[216] The amount of these elements contained in a shipment of fuel is determined by a chemical analysis conducted at the generating station and the results are given as percentage of the coal weight.

In quoting a price for a quantity of fuel, the supplier specifies the minimum heat content of the fuel as well as the maximum allowable quantity of other impurities. Any deviation from these specifications, as determined by the utility's chemical analyses, usually results in an adjustment of price paid for the shipment of fuel such that the quoted cost per BTU is maintained.

16.2 FUEL TRANSPORTATION

The mode of transporting fuel from its source of supply to generating stations varies from station to station. Coal is generally transported from the mines to stations by rail. In some cases, due to the location of generating stations and regional geography, a portion of the coal transportation route is accomplished by barge. Addi-

[215]In most of the world, the unit of energy used is the joule, which is one watt-second of energy.
[216]Sulfur is combustible and is usually burned; the heat obtained by its burning is included in the heat context of the fuel.

tionally, some coal plants have been built at or near coal mines (mine-mouth plants), with the fuel supplied by conveyor belt or by a short utility-owned rail link. The approach of generating at the coal mine site and transporting the electrical energy by transmission lines is often referred to as *coal by wire*. An obvious benefit is that it avoids overdependence on any one rail line.

After delivery, the coal is deposited onto a coal storage pile. From there it is fed by conveyors into the hoppers of the generating stations. These hoppers are large bins designed to hold enough coal to run the generating unit for up to 24 hours between refills, depending on the output level of the unit. Before being fed to the boiler, the coal passes through a series of grinders and pulverizers that reduce the coal to a proper consistency. These particles of coal are mixed with air and blown into the boiler and burned.[217]

Oil and natural gas generally arrive at the generating system by way of pipelines. Although some storage of oil is maintained, there is a closer correlation between delivery and use of these fuels than with coal. A large coal-fired power plant might receive one 80-car coal train per day and maintain as much as 90 days use in storage. Oil tends to flow into a power plant on an intermittent basis with storage facilities for about 30 days. Gas is usually taken directly off of a pipeline with no storage at the power plant.

16.3 FUEL DIVERSITY

A major consideration when planning power plants is to ensure a diversity of fuel supply. There have been a number of instances in which overdependence on a single fuel has had serious consequences resulting in outages well beyond reserve levels considered adequate when planning and operating the power system and in severe increases in the price of electricity. In the early 1970s, some utilities on the Eastern seaboard that were heavily dependent on foreign sources of low-sulfur oil experienced near operational and financial collapse at the time of the Arab oil embargo. Coal burning utilities relying on barge deliveries of coal along the Mississippi River have experienced severe shortages when a prolonged cold spell froze the river. They have also had issues with

[217]The coal is the consistency of talcum powder for pulverized furnaces, pea size for cyclone furnaces, and chunky size for stokers.

freezing coal storage piles at the generating stations. Other coal burning utilities have experienced price shocks when the railroad supplying their coal increased haulage rates. Wind farms can be affected by the unpredicted unavailability of wind resources at critical times. This issue will become critical as the nation greatly increase its dependence on wind powered resources. In some areas of the country, large amounts of capacity are dependent on single gas transmission lines for their fuel. Disruption to any single gas pipeline could effectively shut down many thousands of megawatts of capacity.

16.4 FOSSIL FUELS USED

As discussed in Chapter 2, Table 2-1 shows the generating capacity in the United States in 2007 by fuel type. Table 2-2 shows the types of fuel sources used to produce electricity in the United States in 2007. Natural gas use has experienced the largest percentage increase in use since the 1990s, but coal is still the predominant fuel used to produce electricity.

Natural gas remains the predominant fuel selected for proposed new generation. It causes a lower environmental impact than the other fossil fuels and is currently readily available. One of the major concerns, however, is the ability of gas pipelines to supply long-range future requirements and the ability of the gas industry to meet both electric system and local space- and water-heating requirements.

The primary advantage of coal is its availability in the United States[218] and that there is an infrastructure in place to mine and transport it. However, coal has major environmental drawbacks. Depending on the type of coal used and furnace design, burning the coal emits compounds containing varying amounts of several major pollutants, including sulfur dioxide, nitrogen oxides, particulate matter, mercury, and lead.

Coal is usually classified as high sulfur or low sulfur. The procedures to meet environmental requirements vary. Power plants have various devices such as precipitators and flue gas desulphur-

[218]An ASME Paper, "The Need for Additional U.S. Coal-Fired Power Plants," reports that "The National Mining Association estimates that U.S. coal reserves equal approximately 275 billion tons, which at current recovery and usage rates will last about 200 years."

ization systems to help. Another alternate that has been considered for meeting environmental requirements is the fluidized bed boiler. Debate over coal burning's contribution to greenhouse gases and global warming has become increasing contentious and may result in increasingly severe environmental restrictions or even prohibitions on its use.[219,220] Another major issue relating to coal is how to dispose of the large amounts of residual ash from its combustion.[221] Although NO_X added to the atmosphere is an important factor, most of this is related to the nitrogen in the air supplied for combustion and not the nitrogen in the fuel.

It is anticipated that concern over the threat of climate change will lead to a requirement that the carbon dioxide emitted by the combustion of fuel will need to be captured and then transported to sites for long-term (geologic) storage.

The most common type of oil used in steam electric generating stations is residual or #6 oil. This grade of oil must be heated before it can be introduced into the boiler.

In addition to being used as a starting fuel and as a flame stabilizer (when mixed with coal), #2 oil is also extensively used to run generators that are driven by diesel engines. The quantity of #2 oil used for these purposes is usually small enough to permit delivery by tank truck with a minimal amount of storage. This is also the technology that dominates the market for standby or emergency generators at locations where the need for very high reliability or stand-alone electric generation when severe weather or other emergencies occur.

[219]Matthew Wald in a in a December 18, 2008 *New York Times* article reported that "Officials weighing federal applications by utilities to build new coal-fired power plants cannot consider their greenhouse gas output, the head of the Environmental Protection Agency ruled late Thursday. The Supreme Court ruled last year that the agency could regulate carbon dioxide, the most prevalent global warming gas, under existing law. The agency already requires some power plants to track how much carbon dioxide they emit. But a memorandum issued by Mr. Johnson late Thursday puts the agency on record saying that carbon dioxide is not a pollutant to be regulated when approving power plants. He cited 'sound policy considerations'."

[220]Coal burning produces approximately twice the CO_2 per million BTU that oil does; natural gas produces the least.

[221]The failure of an ash pond releasing 5.4 million cubic yards at TVA's Kingston Fossil Plant in Tennessee in December 2008 illustrates the concerns associated with materials contained within the ash and the disposition and storage of the ash. See *New York Times* article, http://www.nytimes.com/2008/12/30/us/30sludge.html.

Some fossil-fueled power plants operating in the United States today have been designed with the capability of burning more than one type of fuel. This capability is usually designed into the combustion section or the furnace. Even if fuel handling equipment or alternate fuel storage capabilities do not presently exist at a power plant, this capability of burning an alternative fuel remains a valuable design feature. Over the past 15 years, the ability of burning alternate fuels in power plants has enabled utilities to mitigate the effects of long-term disruptions and response to significant shifts in the prices of fossil fuels. In some regions, the focus has been on dual fuel plants in which natural gas or coal can be used to benefit from lower prices for natural gas in the summer and shoulder seasons.

16.5 RENEWABLE ENERGY

There is a growing political sense that wind and solar power could displace all sources of generation using fossil fuels. Many experts feel that these proposals must face and solve significant technological issues.

Since the prime mover sources (wind and sunlight) are not always available at times of need (at night and during cloudy and raining periods for solar, and during calm periods for wind), backup generation or large-scale energy storage systems, possibly as much as 100% of the capacity of the renewable, energy must be developed and installed. Work has been underway for decades on battery storage systems, flywheel storage, and other types of storage as a possible solution, but no significant breakthroughs have happened.[222]

The prime locations for both solar or wind power are not near existing major transmission corridors. "It is common to classify areas (i.e., of the United States) into one of seven wind classes according to the wind speeds at a specified height above the ground; see Figure 16-3. With moderate exceptions to account for protected areas, urban areas, wetlands, and other unavailable areas, the United States has areas with 3500 gWs of "excellent" (above Class 4), wind resources. Interestingly, the states that boast the largest wind power capacity—California, Texas, Iowa, and Minnesota—do not have a large deal of excellent (Class 5), outstanding (Class

[222]See discussion of energy storage in Chapter 8.

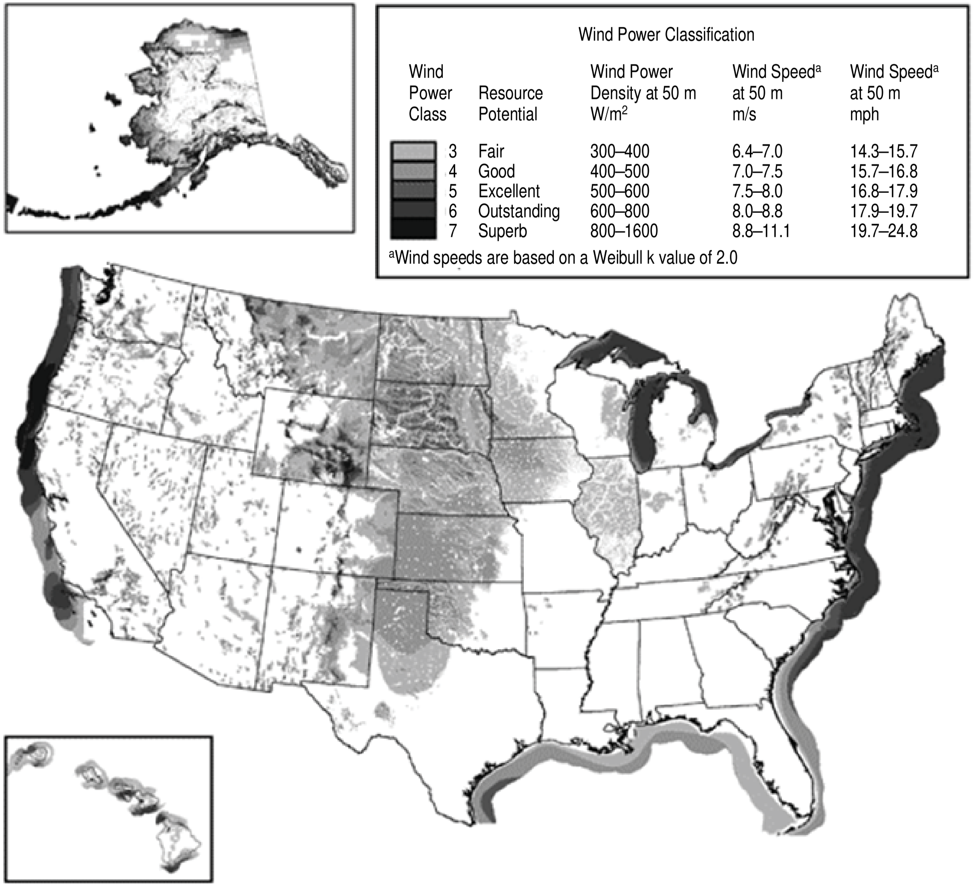

Figure 16-3. Wind potential in the United States.

6), or superb (Class 7) wind capacity. They primarily fall in regions classified as having fair (Class 3) or good (Class 4) wind resources. This speaks to the power that public policy has to encourage project development.[223]

To integrate large-scale wind turbine developments, a number of conceptual designs have envisioned construction of a significant number of new 765 kV transmission lines and HVDC interconnections between the Western United States, Eastern United States, and the ERCOT area of Texas.[224] These lines would face their own group of opponents and could complicate the operation of the transmission network. Offshore wind farms would require extensive HVDC cable installations.

16.6 FUEL PURCHASING

Each generator may obtain fuel from several sources under a mix of arrangements. Some generators have long-term contracts for most of their fuel requirements, with the price fluctuating over time but the quantity guaranteed. Other generators rely mainly on spot market purchase of fuels. Many generators use a combination of both procurement strategies to help ensure a continued supply of fuel at the lowest practicable price.

16.7 EMISSION RIGHTS

The 1990 changes to the Clean Air Act addressed concerns over acid rain pollution. The Act authorized a market-based cap-and-trade approach to reducing pollutants. In this approach, a cap was set on the total amount of a pollutant [say, sulfur dioxide (SO_2)] that may be emitted by electric power plants nationwide. If a plant is able to operate and emit less that its cap value, it can bank the difference for future use or it can sell the difference. Initially, SO_2 emissions were targeted.

Subsequently, nitrous oxides (NO_X) were addressed. The Budget Trading Program (NBP) is a market-based cap-and-trade pro-

[223]www.ieee.org/web/emergingtech/discourses/windpower/windpower_location.html.
[224]See Figure 1-10 in the DOE-sponsored report—20% Wind Energy by 2030—at http://www1.eere.energy.gov/windandhydro/wind_2030.html.

gram created to reduce the regional transport of emissions of nitrogen oxides (NO_X) from power plants and other large combustion sources that contribute to ozone nonattainment in the eastern United States. NO_X is a major precursor to the formation of ground-level ozone, a pervasive air pollution problem (also known as *smog*) in many areas in the East.[225]

As noted earlier, in late 2008 considerable political pressure was exerted to regulate emissions to control the release of greenhouse gases (GHG), especially carbon. Two approaches were offered to control carbon emissions: a carbon tax and a cap-and-trade market. The Environmental Defense Fund explained cap-and-trade as:

> The "cap" sets a nationwide limit on emissions, which is lowered over time to reduce the amount of pollutants released into the atmosphere. The "trade" creates a market for carbon allowances, helping companies innovate in order meet, or come in under, their allocated limit. The less they emit, the less they pay, so it is in their economic incentive to pollute less.

As noted in Chapter 1, the cap-and-trade approach is used in Europe and is the preferred method of the Obama administration in the United States, although even with this approach some recommend caution. These approaches do not specify what technological approaches should be used but rather assume that a market solution will result in a reduction of greenhouse gas emissions. In essence, a cost penalty will be levied on emissions over a targeted level. Over time, the targeted level becomes more and more restrictive. The potential financial impact on utilities and their customers under these financial approaches has given rise to significant concern, especially in areas of the country where the electricity is produced by coal burning power plants. At the time of the writing of this edition, a cap-and-trade mechanism was included by the House of Representatives in its version of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES Act).

[225]A discussion of cap-and-trade activities can be found in the EIA Report, "NO_x Budget Program 2007 Progress Report," Published December 2008, http://www.epa.gov/airmarkets/progress/nbp07.html.

CHAPTER 17

THE BUSINESS NETWORK: MARKET PARTICIPANTS

17.1 INVESTMENT AND COST RECOVERY

As with any other business, those investing in the electric power business expect to receive a return on their investment commensurate with the risks involved and a return of their investment over a reasonable period of time. Prices must be set to enable the investors to recover all their costs, including taxes, plus return of their investment, and a return of their investment. The return on their investment, they believe, should justify the perceived risks they are taking. Ultimately, the economic justification for investments depends on the resulting prices for the product or service. Prices must be adequate, but they are affected by commercial policies, subsidies, taxes, and other factors that are subject to change and man-made decisions.

The electric utility business from its inception has been capital intensive with facilities installed having long service lives and, therefore, long periods required for recovering the investments involved.

Both engineers and economists had found in the past that a vertically integrated power company having exclusive rights to serve a "franchised" area provided significant benefits since it facilitated the long-range optimization of the total supply system from the fuel source to the customer's meter. Significant cost reductions also resulted from centralized planning, operating, purchasing, and legal and administrative staffs.

Important financial advantages were also possible since revenue from one portion of the business would help to provide funds if a large unanticipated cost increase occurred in another

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portion of the business. An example is the need for large amounts of money to repair a distribution system after a major hurricane. With a vertically integrated organization, funds from power sales and transmission system use could help provide the required funds. This diversification of risk was an important asset of the vertically integrated utility business.

However, some believed this structure prevented competition that could produce significant benefits.

17.2 THE CHANGING INDUSTRY STRUCTURE

In the late 1980s and early 1990s, a significant movement arose in the United States for a change in the structure of the electricity supply industry. This movement was driven by a number of factors, including large increases experienced by utilities in the cost of building new generating facilities; by the perception of industrial customers that their rate tariffs were too high, in part because they were being required to subsidize residential customers; and by the success of independent power producers in response to the PURPA legislation of the late 1970s. Supporters of restructuring proposed that the vertically organized electric utility, with captive customers and regulated by government, be replaced with a more competitive environment.

It was not always recognized that key to the success of competition is that ways must be developed to reward those who improve productivity and who create additional savings. Because of the unique nature of electric power systems, major difficulties arose in achieving this result. Many believe it has increased costs and decreased reliability, and is merely a means of reallocating costs and profits.

Functional Unbundling

For competition in the sale of any commodity to be effective, all potential suppliers must have the ability to deliver their product to the customers. The first issue that was addressed by FERC was the availability of access to the utility-owned transmission system. In Order 888, FERC mandated that utilities that owned generation and transmission assets “functionally unbundle” them; that is, as a minimum establish communication boundaries between the two functions within each company. At first, this required keeping separate books of account for each business. Subsequently, pressure increased to make separate companies for each system.

This was followed by FERC pressure to transfer operational control of their transmission facilities to independent third parties.

Additional Utility Responses

In addition to the functional unbundling, utilities responded to restructuring pressures in a variety of other ways:

- Forming ISOs and then RTOs, primarily by members of old-line power pools. Initially, most, if not all, of the existing power pools filed for approval as independent system operators and were granted that status after complying with FERC's rules on independence.
- Splitting their companies into separate business units[226]
- Forming holding companies and establishing themselves as subsidiaries so as to facilitate other nonregulated activities such as independent power production and power marketing
- Entering the EWG market, both in the United States and overseas, through unregulated subsidiaries
- Divesting their power plants
- Seeking mergers to acquire economies of scale as well to provide additional sources of revenue to support nonregulated activities

ISO/RTO Formation

As discussed in Chapter 11, many utilities belonging to power pools formed ISOs and then RTOs, whereby they ceded operational control of their transmission assets to these third parties.

Holding Company Formation

Reversing the reduction in the number of holding companies, encouraged by the SEC in the 1935 to early 1950s period, many utili-

[226]The first system to form separate companies was the Oglethorpe Power Company, which unbundled to form a generation company, a transmission company, and a system operation company in 1997.

ties sought to establish holding companies to give them the flexibility they felt they needed to survive in the new environment. Under the new holding company structure, the regulated utility became a subsidiary of the holding company. The holding company could also establish unregulated subsidiaries, which many did in areas such as generation, energy marketing, and various forms of energy services. Some companies transferred their generating assets to nonregulated generating companies.

As noted in Chapter 14, EPAct05 repealed the PUHCA and replaced it with a new PUHCA of 2005. This new legislation transferred oversight of utility holding companies from the SEC to FERC. The original PUHCA was an attempt to prevent financial abuses of regulated utilities facilitated by complex holding company structures and interlocking directorates. Over time, complaints about the administrative burden to holding companies of demonstrating that cross subsidization did not exist was persuasive to lawmakers. The newly enacted PURPA significantly reduced regulatory oversight of holding companies.

FERC envisions a much lighter regulatory hand over utility holding companies than SEC exercised. In an April 20, 2006 Commission Meeting Statement, FERC Chairman Joseph T. Kelliher stated:

> In the PUHCA repeal rehearing order, we affirm our determination in the final rule that persons that own only exempt wholesale generators (EWGs), qualifying facilities (QFs), or foreign utility companies (FUCOs) are public utility holding companies. The rehearing order reaffirms these holding companies receive a blanket exemption from the PUHCA 2005 books and records requirements and the Commission's PUHCA regulations and clarifies that this is a self-effectuating exemption.

He added:

> With respect to the argument that the Commission should adopt regulations to prohibit public utilities from providing financial support to the non-utility businesses of their parent holding companies, the order notes PUHCA 2005 is primarily a books and records access statute and does not give the Commission any new substantive authorities, other than the requirement regarding review of certain nonpower goods and services cost allocations. In addition, PUHCA 2005 does not give the Commission the authority to pre-approve holding company activities.

Public summary information on holding companies has become less readily available since the repeal of PURPA.

Power Plant Divestitures

In four states,[227] state law required power plant divestiture. In others, divestiture was tied to the utilities' efforts to secure recovery of stranded investment. The market value of a power plant was considered to be the surest way to determine the stranded cost of a power plant.

Divestitures were of two types:

1. To a nonregulated subsidiary of the utility[228]
2. To an independent, nonregulated company

In most cases, the independent companies purchasing the generation assets were nonregulated subsidiaries of holding companies that also had a regulated company subsidiary.[229] However, there were also purchasers who were part of the new generation of nonregulated power companies.[230]

Because of concerns about the purchaser acquiring market power, if a single buyer acquired all of a utility's generation assets, many states limited the amount of capacity that any one entity could buy.

NRG, Reliant Industries, US Generating Company, Mission Energy, and the Southern Company were among the companies purchasing the largest amount of fossil/hydroelectric capacity. Based on published information, purchase prices for hydroelectric and fossil fuel plants were usually in excess of book value, sometimes well in excess. There are two main explanations given of why companies were willing to pay more than book value. The purchasers thought that:

- They would be able to recoup the cost of the plants in the higher energy prices in the new markets being formed

[227]California, Connecticut, Maine, and New Hampshire. Texas placed a limit on the amount of generating capacity any one entity could have.
[228]Illinois Power, Public Service Electric & Gas.
[229]US Generating—PG&E; Houston Industries/Reliant Power—Houston L&P; FPL Group—Florida P&L; Edison Mission Energy—SoCal Edison.
[230]Calpine Energy, Sithe, Dynergy.

- The sites that the plants occupied had an intrinsic value because of the availability of transmission, water, and fuel delivery systems

Perhaps the most surprising occurrence, at first, was that there was a market for nuclear power plants. Entergy, FPL, Exelon, Constellation Energy, and Dominion Resources were among the companies acquiring nuclear assets. The new owners believed that their skill in operating nuclear plants, rising fossil fuel prices, and increasing air pollution concerns would make their investment profitable. This view is supported by referring to Tables 2-1 and 2-2. Nuclear power's share of the electric energy market is significantly higher than one would expect by just considering the installed nuclear capacity. SCANA Corporation, the Southern Company, UniStar (a joint venture of Constellation Energy and EDF), and NRG Energy are some of the companies actively pursuing approval for building new nuclear generators.

Subsequently, reflecting the economic turndown, and revisions of market rules, a number of companies have sold off the generating assets they acquired to relieve themselves of the heavy debt load they used to acquire the assets.

Experience has shown that forced divestiture will not solve market power abuses. In fact, forced divestiture can create market power problems, especially if there is a shortage of generating capacity in the region. To protect consumers from possible market power abuses, California's shareholder-owned electric companies were strongly encouraged by the state's restructuring law to sell their fossil-fuel-powered generating assets. Electric companies in California were required to buy power on the "spot market." Long-term, fixed-price contracts were not permitted, preventing utilities from locking in stable prices over a long period. The sale of generating assets meant that the distribution utilities did not own enough capacity to meet their customers' demands. When spot market prices for electricity spiked, shortages, rolling blackouts, and financial chaos resulted for electricity providers and consumers.

Forced divestiture was but one of the many factors that helped bring about the recent breakdown of the California electricity market, but forced divestiture played a key role by denying companies the needed capacity to fully serve their customers' needs.

17.3 NEW STRUCTURES

As a result of unbundling, the participants in the new industry structure became the:

- Power producers
- Transmitters
- Distributors
- Power marketers
- Independent transmission companies
- Independent transmission operators

Power Producers

The power producers include:

- The existing investor-owned, cooperative, municipal, and government-owned systems that retained ownership of their existing generators and, in some cases, installed additional generation.
- Nonutility power producers who purchased existing power plants or installed new ones to produce power for sale to others. These producers were both new entrants to the utility business or were subsidiaries under a holding company structure of old-line utilities.
- Federal systems producing power for sale, including TVA, BPA, and SWPA.

Independent Transmission Companies and Operators

Originally, transmission service was provided by the vertically integrated utilities and Federal agencies such as TVA and Bonneville. These systems later interconnected with each other to achieve economic benefits, as discussed in Chapter 6, which also discusses the functions of the transmission system. With the advent of restructuring, the purpose of the transmission system was reoriented to become the means of facilitating competition in the bulk power electric market in the sales and purchases of electric energy. As discussed in the Functional Model section of Chapter 10, the new industry structure recognizes two aspects of transmission: the owners and the operators.

Impact of Restructuring on the Transmission System

At first, this new requirement diminished the attention given to the other previously discussed transmission function, reliability. The transmission system's role in reducing total generating capacity requirements[231] often became neglected and transmission constraints became more and more frequent.

U.S. transmission systems are aging, with some important facilities having ages in excess of seventy-five years. Due to the uncertainty relating to the regulatory treatment of transmission as restructuring efforts were underway, the concern by some utilities that increasing transmission capacity would reduce the competitive advantage of their own generation facilities and the difficulties in obtaining state regulatory approval for new transmission lines, very little in the way of new transmission facilities was added in the late 1990s and early 2000s. Meanwhile, competitive pressures to reduce costs caused reductions in maintenance expenditure.

The combination of these effects led to an aging transmission system with increasing outages and a large backlog of maintenance requirements. As noted in Chapters 13 and 14, a number of FERC orders have been directed at removing or eliminating the aforementioned impediments to new transmission construction.

At present, increasing attention is also being given to "merchant transmission" companies that would make investments in specific transmission lines and be directly compensated for their use.

Distributors

The final delivery of electric power is accomplished by the subtransmission and distribution systems, except for a few very large consumers who are supplied by the transmission system. The distribution system is still regulated by local authorities and charges for its use are still under the traditional cost of service approved by the state regulators.

In recent years, recognition that dispersed generation connected to the distribution system and the potential impacts of Smart Grid technologies can affect both the local distribution system and the performance of the bulk power system is causing reevaluations of how the distribution system should be regulated.

[231]This is often called the capacity benefit margin or CBM.

Power Marketers

With unbundling and restructuring of the bulk power market, it became feasible for electric power suppliers and large consumers to choose from a number of power suppliers. This offered an opportunity to form marketing organizations to buy and sell power, trading sometimes a day or two ahead of time and sometimes hourly.

These marketing organizations are sometimes in the corporate structure of existing large utilities that also have considerable generation and transmission assets, and sometimes they are purely trading organizations.[232,233] Theoretically, these trading organizations create economic benefits by enabling purchasers to obtain lower cost power and, through competition, driving down overall power costs. These organizations also provide a means of guaranteed future electricity costs, hedging against potential volatile prices. This is a form of insurance for which the trading company can earn revenue, but which increases the cost of electricity.

Practically, many of the trading organizations became a mechanism for "gaming" the market to increase their profits at considerable expense to the overall American public. This gaming was accomplished in some cases through fraud and false bookkeeping and accounting. In other cases it was accomplished through legal manipulation[234] of the systems and schedules, and collusion with the power providers.

At first, the growth in activity by marketers was phenomenal, but in the early 2000s criminal and other investigations resulted in the demise of some of the larger power marketing organizations. Large utilities, banks, and reputable financial institutions seem destined to be the surviving marketing organizations.

17.4 NEW CORPORATE OWNERSHIP

After a long period of ownership stability, the electric utility industry in the United States has experienced significant changes in

[232]Enron was this type of organization.

[233]FERC maintains an Internet-accessible database of all companies it has granted approval for charging market based rates. These companies include investor-owned utilities, power marketers, financial marketers, affiliated power marketers, and affiliated power producers.

[234]Although they are legal, some consider these manipulations a violation of the code of ethics for the professions involved.

the size and ownership of the entities that generate, market, and deliver electric power. Existing utilities have merged, forming larger and larger entities, and foreign companies and financial institutions have acquired U.S. companies.[235] Electric and gas utilities have merged as have merchant power companies.

Utility Mergers and Acquisitions

There have been numerous utility mergers seeking primarily to achieve efficiencies due to economies of scale. As a result, many small companies have been acquired and merged into larger ones. There are a number of instances in which a company formed by a merger acquires an additional company, or is itself acquired, resulting in larger and larger companies. Some examples are:

2005—Duke Energy Corp. and Cinergy Corp
2001—First Energy Corp. and GPU
2000—Florida Progress Corporation and CP&L Energy
1998—Exelon and PECO
1997—AEP and Central and Southwest

In October 2008, Exelon made an unsolicited offer to buy all of NRG Energy. If that acquisition is completed, Exelon would be the largest owner of generating capacity in the United States. In March 2009, NRG announced that it had an agreement to purchase Reliant Energy Inc.'s Texas retail business. Earlier, in 2006, NRG had purchased nearly 11,000 mW of assets from Texas Genco. NRC is also reportedly on NRC's short list for approval to construct a new nuclear reactor using Toshiba's Advanced Boiling Water Reactor (ABWR) design. They are partnering with CPS Energy and the South Texas Nuclear Operating Company.

Acquisitions by Foreign Companies

The industry reflects the movement to globalization. Some have expressed concern over whether foreign firms should control vital U.S. infrastructure. Electricite de France (EDF) has announced its ambition to become a player in the nuclear energy sector in the

[235]See http://www.ferc.gov/industries/electric/gen-info/mergers/mergers-2007.asp for a list of approved mergers and acquisitions since 1995.

United States and has agreed to purchase 49.9% of Constellation Energy's nuclear plants, and it is also active in the production of renewable energies. EDF and Constellation are on the shortlist for NRC approval for construction of new nuclear units at the Calvert Cliffs site using Areva's evolutionary power reactor design. The National Grid Company, a subsidiary of National Grid plc, a London-based company, has acquired significant transmission assets in the Northeast United States with its purchases of utilities in New England and New York. In 2007, Iberdrola, a Spanish utility holding company, acquired Energy East which had three main subsidiaries: New York State Electric and Gas, Rochester Gas & Electric, and Central Maine Power. Iberdrola also has an indirect, 100% interest in PPM Energy, Inc. and its subsidiaries, including various wind and thermal energy facilities; natural gas marketing, storage, and hub services; and other energy services. The facilities are primarily located in California, Colorado, Iowa, Minnesota, and Oregon.[236]

Financial Institutions

In the recent past, perhaps the most significant change in the ownership structures in the utility industry is the direct involvement of financial institutions. Some have purchased outright utility assets and some have taken equity positions in marketing and power plant development projects. Berkshire Hathaway has purchased utilities in the Midwest United States (MidAmerican Energy) and in the Northwest (PacifiCorp). In exchange for its financial aid, it will acquire a 9.99% interest in Constellation Energy, an East Coast utility. It has also purchased CalEnergy, a firm specializing in power production from geothermal energy and other renewables. In 2007, Kohlberg, Kravis Roberts & Co., one of the world's largest private equity firms, in association with Goldman Sachs and TPG, acquired the three entities making up TXU: TXU Energy, a market-competitive retailer; Luminant, Texas's largest power provider, with 18,300 mW of generation capacity, including a 2300 mW nuclear unit; and Oncor, Texas's largest regulated electric delivery business, the sixth largest in the United States.

[236]www.ferc.gov.

CHAPTER 18

THE MONEY NETWORK: WHOLESALE MARKETS

A vital part of understanding the electric power business is understanding the functioning of its money network. This network consists of the various sources of money, the various paths and organizations through which this money flows, and the uses of the money, including payments of expenses, investment in new plant and equipment, payment of interest and principal on debt, and dividends.

This money network is tied to the physical and energy networks at various points, with the flow of money having important effects on their development and operation. The money network is controlled by both the business and regulatory networks, and uses the physical generation and communication networks.

Money sources are similar to generators in electric power systems. By diagramming the sources of money, its flow through the various networks, and the uses, charges, or profits for various functions, we can get a far better understanding of how the financial systems work and are related to electric power policy. Diagrams of the flow of money through electric utilities have been prepared in the past by engineers, starting in the early 1960s.[237] It is important to identify the connection points between the money network, the energy network, and the power network. What happens to one affects the others. Although some components of the money network are regulated, others are not; yet, one needs to look at the entire picture to get a full understanding of whether the overall system is being manipulated.

[237]See CIGRE paper presented in 1962 by H. K. Sels and J. K. Dillard.

As with any business, utilities receive money from two primary sources: customers and investors. However, there are differences between utilities and most other businesses. Historically, the revenues received by utilities from end use customers were under rate tariffs set and approved by state regulators, municipal agencies, or cooperatives. These tariffs reflected a recovery of utility expenses and, for state regulated utilities, a predetermined return on the utility's investment. Revenues received from other utilities for the use of their transmission system were under rate tariffs that were approved by FERC. Since the utility was, in effect, guaranteed a fixed rate of return on its investment, its financing costs were relatively low.

The utility's tariffs were structured to reflect different customer classes, primarily residential, commercial, and industrial. Cost-of-service studies were conducted to allocate costs to each class of customer. Costs themselves were divided into different categories: generation, including fuel costs, transmission, and distribution; and administrative and general.

An important consideration for many utilities was the cost of fuel for generation, which could experience a high degree of volatility. To shield utilities from adverse cash flow problems, some regulatory jurisdictions implemented fuel adjustment clauses in the utility's rates. These clauses allowed the utility to add incremental charges (or to reduce their charges) if the cost of fuel in any period varied from the cost reflected in its rates.

Federal and state tax policies also have a significant impact on utility cash flow. Some tax policies are meant to encourage utility capital investments. In some jurisdictions, taxes or surcharges on utility revenues are used as a means of raising funds for the state in lieu of income taxes.

The determination of a utility's investment, or its rate base, has peculiarities unique to the industry. Besides the nondepreciated installed plant, state regulatory commissions have defined so-called regulatory assets. These assets cover a variety of issues but are intended as a means to spread the recovery of costs over a long time period rather than as an immediate expense.

18.1 THE ENERGY MARKETS

A major determinant of a utility's cash flow is its costs for electricity, whether it buys the electricity on the wholesale market or whether it generates its own.

Historically, customers of the electric utility industry were supplied by their local utility which was responsible for all aspects of the electricity delivery channel: production transmission, distribution, and customer interface. The local utility would own its own generating facilities or would buy some or all of its requirements from other generation owners. Long-term sales of wholesale electricity between utilities were based on bilateral contracts with negotiated prices. Short-term daily or hourly sales were contracted for by a specific seller and purchaser and usually priced at the cost of production plus 50% of the differential between that cost and the avoided cost of the purchaser.

The restructuring of the industry has resulted in a much more complex market environment in the United States. There is no single electricity market or electricity market structure in the United States. The wholesale electricity market, in some parts of the country, is managed by RTOs/ISOs whose market rules are influenced by FERC orders. In other parts of the country, the wholesale electricity market continues to be operated by local utilities. Some utilities have divested their generation assets and some have not.

To describe the electricity market structure depends on one's location in the United States. Consideration must be given to three components of the market: the process for buying and selling electric energy, electric capacity, and certain ancillary services at the wholesale level; the rules for the use of the transmission system to deliver the electricity; and the ability of customers to select their electricity providers, that is, whether they must rely solely on the local distribution utility for their electricity or whether they have the right/ability to obtain their electricity from other suppliers (retail access). Note that in this latter case, the customer must still use the distribution facilities of the local utility for the delivery of the electricity.

Starting with PURPA in the late 1970s, there has been an effort at the Federal level to promote an open wholesale electricity market. Some states took steps to establish retail electricity markets. The Federal effort gained significant support with the passage of the Energy Policy Act of 1992. In response to the direction of that Act, FERC issued Orders 888 and 889, which were intended to open the transmission system for use by all potential wholesale energy suppliers (open access). It required that vertically integrated utilities functionally separate their energy supply and their transmission functions to avoid the potential for self-dealing. It encouraged utilities to cede operational control of their transmission facilities to independent third parties (ISOs). As a result of these orders, utilities were required to file Open Access Transmission Tariffs (OATT), which FERC has used as the mechanism to ensure standardized treatment for the use of the transmission systems countrywide.

In subsequent orders, FERC continued to address what it perceived to be imperfections in the provision of open transmission access. In Order 2000, FERC encouraged the formation of regional transmission organizations which, among other responsibilities, would include market monitoring and interregional coordination of market issues. In a Notice of Proposed Rulemaking (NOPR),[238] issued in 2002, FERC continued to address transmission access issues but it also presented its view of a wholesale electricity market (the Standard Market Design or SMD).

In some areas of the country, the utilities, often under pressure from local state regulators, complied with FERC's directions and formed ISOs and RTOs, and implemented the SMD. In other areas of the country, usually where the cost of electricity was on the low side of the national average, the efforts were vigorously opposed. As part of the Congressional negotiations to pass EPAct05, the implementation of the SMD on a national basis was stopped. In a notice issued on July 7, 2005, FERC terminated the SMD proceeding, citing the continuing development of voluntary RTOs and ISOs and the Commission's expressed intent to look into revisions to the Order No. 888 pro forma tariff in a separate proceeding.[239] This has resulted in two different market structures in the United States: one recognizing the principles enumerated by FERC in its SMD and another based primarily on an individually negotiated bilateral contracts/self-generation model.

Standard Market Design (SMD)[240]

Although the SMD was never implemented by FERC, we include a discussion of its provisions covering wholesale markets, since

[238]"Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design." For a summary see www.library.findlaw.com/2002/Jun/25/132372.html.

[239]FERC subsequently issued Order 890, addressing what it perceived as outstanding issues relating to open access to the transmission system.

[240]Much of the material in this section is excerpted directly from FERC's SMD NOPR. We cover the SMD in the money network chapter since the SMD extends FERC's reach into the operation of the wholesale energy market.

these provisions are illustrative of the functioning of the markets in RTOs/ISOs.

To remedy the negative impacts it perceived to be due to differing market structures, FERC proposed a new standardized market design. The wholesale market would rely on both bilateral contracts between buyers and sellers, and short-term spot markets:

> The fundamental goal of the Standard Market Design requirements, in conjunction with the standardized transmission service, is to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries and that allow customers to receive the benefits of lower-cost and more reliable electric supply.

FERC felt that the use of bilateral contracts would lessen the impact of power generators, presently supplying local areas, seeking higher priced markets elsewhere, since the local consumers could buy their power under long-term contracts.

The short-term spot markets would:

- Be operated by the independent transmission providers (ITPs)
- Be bid-based and security constrained
- Cover two time frames: a day ahead and real time
- Use a market-based, locational marginal pricing (LMP) transmission congestion management system

The market would have

- Tradable financial rights to allow a fixed price for transmission service (congestion revenue rights)
- An auction process to allocate these rights
- A power market monitoring system and market power mitigation rules

Locational Marginal Pricing (LMP)

The locational marginal price is the marginal cost of supplying an increment of load at each bus on the system. The major factors affecting these prices are the generator bid prices, whether there are any transmission system elements that are experiencing congestion, the losses on the system, and the electrical characteristics of the system.

Although there are some variations from system to system, the basic approach of an LMP market is as follows. To meet the forecast load in each period (typically an hour), each generator submits bids for the energy it is willing to supply. The market manager schedules the generators from the lowest bid to progressively higher bids until the full forecast load and losses are satisfied. The marginal cost is the price bid by the last, and most expensive, generator selected. Absent transmission constraints, all generators supplying load receive that price for their energy. Likewise all loads pay that price. The receipts from the customers match the payments to the generators.

If there are transmission constraints, that is, if the transmission system in congested, generation is rescheduled to avoid the constraints in the least-cost manner. In this situation, there will be more than one LMP, since the process reflects the bid prices of different marginal generators, depending on their location in the system. Generators are paid for the energy they supply to the market, according to the LMP at their point of connection to the system. Energy consumers buy energy from the market, based on the LMP at their connection point. In this case, although the generation in the constrained area will be more expensive than in a nonconstrained situation, the total receipts from customers in areas that are transmission constrained can be higher, even significantly higher, than the generation cost, since all customers in the constrained area will pay the higher LMP. The difference between the costs and the receipts is referred to as congestion rents.

LMP values may be calculated for different time periods based on the particular rules for the various systems. Many of them have a day-ahead market that uses the scheduled quantities of consumption for the various market participants, the schedules of bilateral contracts, the price bids, and the impact of transmission congestion to determine the day-ahead LMP values. The calculation of the LMP values is based on the optimization problem inherent in the market clearing process. Some systems also have an hour-ahead market. Hour-ahead LMP values can again be calculated as a byproduct of the hour-ahead market clearing process. Finally, real-time LMP values are calculated. These are based on the generation dispatching process used for balancing the system while alleviating congestion. Differences between the LMPs are used as the cost of congestion between any two locations. Loss effects are also included in the calculations of LMPs.

Some experts believe that the use of LMPs increases the cost of electricity over the use of incremental production costs for dispatch and also can increase transmission losses.

18.2 TRANSMISSION

Independent Transmission Providers

FERC's SMD NOPR states that:

> An Independent Transmission Provider is any public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent (i.e., has no financial interest, either directly or through an affiliate, in any market participant in the region in which it provides transmission services or in neighboring regions).[241]

ITPs would be responsible for:

- The administration of the day-ahead and real-time markets for energy and ancillary services
- Long-term planning and expansion, system impact, and facilities studies[242]
- Transmission transfer capability calculations [including postings on an Open Access Same-Time Information System (OASIS)]

Transmission Rights[243]

In order for a competitive wholesale electricity market to function, all sellers and buyers of electricity must have equal access

[241]Recognizing the political difficulties that its proposals face and the multistate nature of the RTOs that it envisioned, FERC indicated that state representatives would have a formal role in the ITP's decision making process. FERC avows that it does not want to interfere with the legitimate concerns of state regulatory authorities.

[242]These studies would include studies of the interconnection of a new load or generator, and studies of the feasibility of simultaneous transactions to deal with congestion revenue rights.

[243]Note that load-serving entities are required to pay network access charges, which cover the fixed costs of the transmission system.

to the transmission system and certitude that this access is long-term and secure. The mechanism to accomplish this is to acquire rights to the use of transmission facilities. There are two types of transmission rights: physical and financial. In most RTOs, a financial system is used based on locational marginal pricing concepts.

Physical Transmission Rights (PTRs)

PTRs provide the owner with the exclusive right to transmit a predefined quantity of power between two locations on a transmission network and, importantly, to deny access to the network by market participants that do not hold transmission rights.[244] Further, PTRs offer the two necessary features of transmission rights. They provide clearly defined property rights because once the PTR is purchased, the holder of that right is assured that capacity will be reserved exclusively for the transmission of power under that right. Also, during periods of high demand, the PTR can be sold to another party, giving them the right to use that same capacity. With a PTR, transmission costs can be determined in advance.

PTRs present numerous problems. A particularly difficult issue is the determination of the physical capability of the various parts of the grid and how much of that capacity a particular transaction will use. Two approaches have been acknowledged by FERC: a point-to-point contract path approach or a flowgate approach.

The right of the PTR holder to self-dispatch can interfere with the transmission system operator's efforts to efficiently schedule and dispatch the system. This can interfere with the reliability of the operations of the transmission system. This reliability issue can be addressed by issuing an amount of PTR that represent less than the full capacity of the system. However, this is inefficient and would prevent cost savings from being realized that result from increasing output in inexpensive locations and decreasing output in more expensive locations.

Moreover, the PTR holder's ability to exclude access to the transmission market presents a problem. If a generator holds a

[244]There is a considerable body of literature addressing FERC's views vested rights to transmission capacity.

PTR for transmission service from point A to point B and owns generation at point B, it could maintain an artificially high price at point B by preventing generators at point A from transmitting power across the transmission system. Thus, the most efficient generators might be at point A, but by withholding transmission capacity, the generator at point B could maintain pricing inefficiencies for its gain.

Financial Transmission Rights (FTRs)[245]

In a LMP market, to provide a hedge against incurring congestion costs when the transmission system cannot deliver all scheduled generation, customers can buy FTRs.[246] FTRs are financial contracts between a market participant (primarily a load-serving entity) and the transmission system operator. Although FTRs are similar to PTRs in that they are defined from a source to a destination and are denominated in a megawatt amount, the key difference is that FTRs do not entitle their holder to an exclusive right to physical use of the transmission system. FTRs provide the rights holder with the revenues associated with congestion between two points (congestion rents); thus, any congestion costs in the energy it purchases are offset by these revenues.

FTRs provide their holders with the right to payments equal to the energy price difference between the source and the destination locations. These payments are funded by the congestion payments that arise when energy is purchased from lower-priced regions to be sold in higher-priced regions and there is insufficient transmission capability causing congestion on the transmission system. A load-serving entity would purchase FTRs as a hedge to offset higher generation costs due to congestion.

FTRs remain one of the most dynamic of issues, since it requires an entirely new perspective on how to fund grid expansion. These issues are complex. FTRs can be viewed as *physical,* offering effectively an admission ticket to allow the holder to schedule a transmission transaction, or as *financial,* as favored in the Northeast, which offers the holder a stream of revenues even if it does not deliver or receive physical energy. It has become

[245]Also known as fixed transmission rights, transmission congestion contracts (TCCs), or congestion revenue rights (CRRs).
[246]Usually in an auction.

apparent, however, that the level of transmission can cause bottlenecks.

Wheeling and Customer Choice

Wheeling is a term sometimes used to describe the transmission of power over the transmission lines of an intermediary system by a seller or purchaser of electricity. The purchaser is usually a wholesale distributor, but can, in some states, also be a retail customer. Wheeling is an essential ingredient in the move to provide customers with the choice of power supplier.

In cases in which an alternate supplier is chosen, the local utility rates are reduced by the revenue requirements associated with the capital and energy costs of the generation it is no longer supplying, leaving only distribution delivery costs. These offset costs are those that an alternate supplier must beat to result in a lower total cost to consumers. Experience to date has shown relatively little customer switching since alternate suppliers generally have higher power costs than the present supplier.

In the early stages of restructuring, many companies attempted to develop business supplying customers in other systems. Many of these efforts were not successful, often resulting in economic losses. As a result, the level of competition in the supply of retail customers has decreased significantly.

Contracts and Agreements

With an unbundled electric utility industry, many new contracts were required, including contracts for power purchases and contracts for transmission services. With the vertically integrated utility, these requirements were coordinated under the direction of a single corporate management. With restructuring, the terms and conditions of the required services must be covered by appropriate contracts.

In addition, coordination contracts can help to achieve lower total system costs because actions by any one company, or failure to act, can affect the costs of other companies. Such coordination contracts are becoming increasingly necessary. One example would be installation of transmission facilities in one system to provide for reduced costs in another system.

Average System versus Incremental Costs

Another issue is the basis of the cost to be charged for use of a transmission system. For example, when a generator is added to the system, a number of transmission costs may be involved:

- The costs to connect the generation to the system
- Reinforcement of or additions to the transmission system, either in the vicinity of the generation addition or possibly hundreds of miles away in other systems
- Changes and replacements in protection and control systems, such as circuit breaker replacements and new relaying arrangements
- The increase in costs resulting from transmission outages while the necessary connection and reinforcement work is done

One approach is to have the new generator pay all of these additional costs. Additional transmission costs can also be incurred if a generator unit is retired, causing increased loading on certain transmission facilities. This raises the question of when the costs would otherwise be incurred if the generator addition or retirement were not made.

The other approach is to include all transmission costs except those of the direct connection in overall system tariffs. This raises the question of why should the existing generators and consumers have to pay more for transmission service because one party has added or retried a generator? It also raises doubts about the selection of the most economic generation additions since the system costs, which are subsidized by all customers, may be much larger for one than another, but do not enter into the competitive decision process. Many, if not most, of these issues have been addressed by FERC in its transmission-related orders.

18.3 CUSTOMER RATE ISSUES

Construction Work in Progress (CWIP)

The general rule for determining the rate base is that facilities cannot be included until they are “used and useful.” In the 1970s, when the regulated utility industry was mired in construction of extremely expensive power plants that were experiencing very long construction times, some state regulators allowed utilities to include in rate base, and to earn a return on, the construction costs incurred prior to the completion and service of the power plant. This became a particularly contentious issue. With proposals to build new nuclear power plants by some regulated utilities, the issue is surfacing again.[247]

Setting of Rates

Although, theoretically, tariffs were designed to reflect the costs to supply each class of customer, practically, political considerations often overrode a fair cost allocation, with large industrial customers frequently charged more than their share to subsidize small consumers, who were a majority of the voters. Large industry often felt that its competitive positions were adversely affected by regulatory decisions, and their answer was to get rid of regulation.

Rate Freezes

The intent of the restructuring of the industry was that the cost of generation reflected in customer bills be set by the marketplace and no longer be a predetermined value. In some jurisdictions, as part of the deal to implement restructuring, the local utility agreed to a rate freeze for a number of years. These rate freezes have given customers a distorted view of the effects of restructuring. As the freezes have expired, large increases in electric rates have raised public concerns.

Allocation of Costs and Economic Benefits

The participants in joint power projects and coordination procedures allocated costs between the participants based on negotiations between the participants, with regulatory oversight and approval. Prior to the restructuring of the electric power industry, coordination between the supplying systems took place to achieve economic benefits. To allocate costs and benefits in projects involving more than one system, a "split savings" approach

[247]In late February 2009, the Georgia legislature voted to allow the Southern Company/Georgia Power to include CWIP in rate base for a proposed new nuclear unit.

was used. This approach was based on review of costs to each of the participants without the joint project and the costs with the project. The benefits from the coordinated procedures were allocated to each participant, sometimes 50/50 and sometimes based on negotiations. This approach was used for projects involving capital investments and for operations such as generation dispatch. It was a key factor in determining the flow of money.

If additional costs were incurred by any participant, they would be compensated for these in addition to receiving their share of the net benefits. With this procedure, all participants in coordinated activities would benefit. It would be a win–win situation for all. This procedure produced a great deal of cooperation and large savings to the public, estimated to be more than $20 billion per year in the late 1980s.[248] These costs and associated benefits were then reflected in the tariffs paid by consumers.

Although new restructuring procedures rely on market forces and competition to achieve cost allocation, especially for generation and the power that the plants produce, major questions exist about the ability of some organizations to exert market power by dominating the market and controlling pricing.

With the advent of restructuring the coordination achieved with the split savings approach has ceased. Results of some analysis have indicated restructuring, has increased overall natural costs for electricity by about 10%[249] from what they would otherwise have been.

Average Costs versus Incremental Costs

One of the concerns in the operation of the new competitive markets is whether prices should be based on average costs or incremental costs. The average cost approach is simpler and often less contentious. The incremental cost approach is often fairer since each use or user of the system will pay for the costs it causes. This question becomes important in determining tariffs and the allocation of additional investments.

[248]Casazza, J. A., Palermo, P. J., Lucas, J., and Branco, F., "Generation Planning and Transmission Systems," 1988 CIGRE Paper. Also EEI publications.
[249]J. A. Casazza, "Electricity Choice: Pick Your Poison—Errant Economics? Lousy Law? Market Manipulation? All Three!," *Public Utilities Fortnightly,* March 1, 2001.

18.4 MARKET VERSUS OPERATIONAL CONTROL

In an electric power system, there are two arrangements for the control of decisions: one by those having market rights developed through operation of the money network, and the other by those having operational control of the physical network. Theoretically, the operation of both of these networks should be coordinated. The operation of the money network should result in the most efficient operation of the physical network.

18.5 MARKET POWER ISSUES

Market power has been defined as the ability of a supplier to profitably raise prices above competitive levels and maintain these prices for a significant period of time. There are two types of market power: vertical and horizontal. A traditional vertically integrated utility might exercise vertical market power by using its control of the transmission system to give its own generation preferential treatment. Avoidance of the exercise of vertical market power has been a focus of FERC's in Orders 888, 889, and 890, and its requirements for each utility's Open Access Transmission Tariff (OATT). A supplier also could have horizontal market power if it controlled a significant amount of the generation resources in an area, especially if the area cannot import power because of transmission constraints. This latter concern was addressed by FERC in Order 697 when granting utilities market-based rate authorizations for wholesale sales of electric energy, capacity, and ancillary services,[250] or by many state regulators by requiring multiple buyers when generation was divested. Another form of market power can involve both vertical and horizontal aspects when a local supplier controls a significant amount of the fuel resources used for generation in an area. Experience has shown considerable problems with attempts to rely solely on market forces to prevent the exercise of market power. Both legal and illegal means have been used by some market participants to create market power situations to obtain large profits while increasing the overall cost of electricity.

[250]See Chapter 11 for a discussion of ancillary services.

Price Caps

Experience has shown that excessive market power, market manipulation, and even illegal market operations have contributed to wide variability in the price of bulk power electricity. As a result, some jurisdictions have instituted "price caps" to limit maximum prices that can be charged in market operations. There are many arguments, pro and con, on the application of such price caps, some claiming they are essential to prevent market abuses, and others claiming they prohibit proper operation of the market.

18.6 THE FUTURE

Concerns have been raised in a number of states about the fairness and openness of the new market structures. Responding to these concerns, in 2008 the State of Illinois created the Illinois Power Agency to, among other things, develop electric procurement plans, to conduct electric procurement processes, and to develop electric and cogeneration facilities. The issue has also been actively discussed in Connecticut. The new electric power markets have been described as "Incredibly complicated,"[251] complex and almost beyond comprehension for noneconomists.

[251]Dan Dolan, vice president of the Electric Power Supply Association as quoted in a *New York Times* March 12, 2009 article, "Warming up: A consumer backlash against rising electricity prices," By Peter Behr.

CHAPTER 19

THE PROFESSIONAL AND INDUSTRY ORGANIZATIONS

19.1 THE PROFESSIONAL ORGANIZATIONS

Many professional organizations are involved in the functioning of the electric power industry. Besides representing the interests of their members, they play an important role in setting technical standards for the various processes and equipment used by the industry. They also provide technical information to government organizations and the public to help define government policy.

The Institute of Electrical and Electronics Engineers (IEEE)[252]

The IEEE is a nonprofit, technical professional association of more than 377,000 individual members in 150 countries. Through its members, the IEEE is a leading authority in technical areas ranging from computer engineering, biomedical technology, and telecommunications, to electric power, aerospace, and consumer electronics, among others.

The IEEE is made up of 10 regions, 37 societies, 4 councils, approximately 1200 individual and joint society chapters, 300 sections, and 1000 student branches located at colleges and universities worldwide.

According to the IEEE,

> Policy matters related to IEEE Standards are the purview of the IEEE Standards Association (IEEE-SA), which establishes and

[252]The material in this section is from the IEEE/PES website, www.ieee.org/organizations/society/power.

> dictates rules for preparation and approval. . . . The Power and Energy Society (PES) is one of the 37 societies in the IEEE. Overwhelmingly, it is the Computer Society and the Power Engineering Society that dominate in this regard, e.g., about 40% of all IEEE Standards are within the PES.

The IEEE is taking an increasingly active role in recommending future government policies and research activities.[253] It has developed the following basic principles for a restructured electric utility industry:[254]

1. Reliability criteria of a single North American reliability organization should be the minimum applied by all systems regardless of the regulatory regime. The organization developing the criteria must possess a depth of technical competence, and the criteria must be applicable to all market participants. State and federal policymakers should recognize these criteria as an authoritative technical basis for system operation.
2. Prices of all market products must be established in a manner that provides proper incentives for reliable behavior of all parties, in addition to providing the correct economic signals to the markets. This factor is essential in satisfying reliability standards. Market and reliability rules must be coordinated to promote overall economic efficiency, provide for effective and efficient dispatch of generation in real time, and anticipate and relieve transmission congestion when it arises. Procedures for fair and effective mitigation of market power must also be developed. Emergency operating protocols must be established to enable maintenance of system reliability when market mechanisms fail to provide the necessary resources.
3. Means and incentives for the effective planning, construction, operation and maintenance of transmission system infrastructure should be incorporated into all market structures. Coordinated generation, transmission and distribution development is essential to assure reliable operation and enable minimization of costs. Market and reliability rules must include provisions to ensure that accurate information is available on a timely basis to those responsible for both long-term development and operational planning. Enforce-

[253]See IEEE-U.S. Policy Position Statement—National Energy Policy Recommendations—January 2009. www/ieeeusa.org/policy/positions/energypolicy.pdf.
[254]http://www.ieee.usa/forum/positions/electricindustry.html.

able contracts that define the requirements placed upon each market participant can assure that proper coordination takes place.

4. Long-term resource adequacy requirements, as typically reflected by installed reserve margins, are necessary to assure that sufficient supply resources are developed. These requirements should be applicable to both integrated and restructured systems. Compliance mechanisms, such as the extent of reliance on organized forward markets, may differ. Information about forward commitments of supply and demand resources to cover load must be made available to system operators. Assessment of reactive power supply adequacy is also a fundamental requirement.
5. Compatibility must exist between the regulatory and institutional framework for the electric industry and the technical fundamentals of the power system. The laws of physics cannot be changed, but the regulatory regime can be designed to accommodate them. Similarly, the regulatory framework ultimately adopted will influence the development and selection of technology solutions.
6. Within the context of the technical fundamentals, policymakers should work cooperatively to establish a clear and stable framework for coordination among state and federal regulators. Regulatory uncertainty regarding the division of responsibility between state and federal authorities is highly detrimental to the reliable and efficient performance of the system.
7. Design of state administered retail rules should facilitate demand response to price and should be compatible with the design of wholesale market rules in a particular region. The IEEE supports specific legislative and regulatory positions in areas where it is qualified.

The American Society of Civil Engineers (ASCE)

The ASCE is a professional organization representing more than 146,000 civil engineers. ASCE is a focal point for the development and transfer of research results and technical policy and managerial information. The ASCE is an important contributor to national policy questions. In "2009 Report Card for America's Infrastructure,"[255] it reported on its review of 15 categories of the U.S. infrastructure, including the electric power grid, and assigned a grade

[255] http://www.asce.org/reportcard/2009/solutions.cfm.

for each category. A grade of D+ was given to the electric grid. The Society is also active in supporting specific legislation and technically qualified individuals for key government positions.

American Society of Mechanical Engineers (ASME)[256] and the American Institute of Chemical Engineers (AIChE)[257]

The ASME is a not-for-profit professional organization promoting the art, science, and practice of mechanical and multidisciplinary engineering and allied sciences. ASME develops codes and standards that enhance public safety, and provides lifelong learning and technical exchange opportunities benefiting the global engineering and technology community. ASME has more than 127,000 members worldwide.

The AIChE is the world's leading organization for chemical engineering professionals, with more than 40,000 members from 93 countries.

CIGRE

Another important organization is the International Council on Large High Voltage Electric Systems (CIGRE). CIGRE is an international organization through which ideas can be exchanged with people from various countries through meetings, committee activities, and its publications.[258] It focuses on the bulk supply system.

19.2 INDUSTRY ASSOCIATIONS

To exchange ideas and to provide an effective voice in government and public relations circles, a number of organizations have been formed.

NEMA[259]

NEMA is the trade association of choice for the electrical manufacturing industry. Founded in 1926 and headquartered near

[256] www.ASME.org.
[257] www.aiche.org.
[258] Material from CIGRE Website: www.CIGRE.org.
[259] http://www.nema.org/about/.

Washington, D.C., its approximately 450 member companies manufacture products used in the generation, transmission, distribution, control, and end use of electricity.

These products are used in utility, medical imaging, industrial, commercial, institutional, and residential applications. Domestic production of electrical products sold worldwide exceeds $120 billion annually.

NEMA provides a forum for the development of technical standards that are in the best interests of the industry and users, advocacy of industry policies on legislative and regulatory matters, and collection, analysis, and dissemination of industry data.

The Association of Edison Illuminating Companies (AEIC)[260]

The AEIC is an association of electric utilities, generating companies, transmitting companies, and distributing companies in North America and overseas. Organized in 1885, the AEIC is the oldest association to be affiliated with the electric utility industry. It provides information exchange through a committee structure, and mutual solutions to industry problems, as well as providing literature on load research and underground cable specifications. The purpose of the Association of Edison Illuminating Companies is:

- To promote the (technology-related) business interests of its members
- To discover and adopt increasingly more reliable, economical, and efficient means for the supply and utilization of electrical energy
- To provide an assembly for the exchange of experiences of electrical properties

The American Public Power Association (APPA)[261]

APPA is the service organization for the more than 2000 community-owned electric utilities that serve more than 40 million Americans. It was created in 1940 as a nonprofit, nonpartisan organization. Its purpose is to advance the public policy interests of

[260]www.aeic.org.
[261]The material in this section is from APPA's Website, www.appanet.org.

its members and their consumers, and provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment. APPA is governed by a regionally representative Board of Directors.

The Edison Electric Institute (EEI)[262]

The EEI, organized in 1933, is the association of United States shareholder-owned electric companies, international affiliates, and industry associates worldwide. In 2000, its U.S. members served more than 90% of the ultimate customers in the shareholder-owned segment of the industry, and nearly 70% of all electric utility ultimate customers in the nation. They generated almost 70% of the electricity generated by U.S. electric utilities.

EEI's mission is to ensure members' success in a new competitive environment by:

- Advocating public policy
- Expanding market opportunities
- Providing strategic business information

EEI works closely with its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. The Institute provides authoritative analysis and critical industry data to its members, Congress, governmental agencies, the financial community, and other influential audiences. EEI provides forums for member company representatives to discuss issues and strategies to advance the industry and to ensure a competitive position in a changing marketplace.

The Electricity Consumer Resource Council (ELCON)[263]

ELCON, founded in 1976, is an association of large industrial consumers of electricity from virtually every manufacturing industry. They consume nearly six percent of all the electricity used in the United States. ELCON describes itself as "a . . . voice for competitive policies and market structures." It strives to lower electricity costs for its industrial members.

[262]The material in this section is from the EEI's Website, www.eei.org.
[263]The material in this section is from ELCON's Website, www.elcon.org.

The National Rural Electric Cooperative Association (NRECA)[264]

NRECA is the national service organization that represents the national interests of consumer-owned cooperative electric utilities and the consumers they serve. The association provides "legislative representation before the U.S. Congress and the Executive Branch, and representation in legal and regulatory proceedings affecting electric service and the environment."

NRECA's electric cooperative and public power district members serve 36 million people in 47 states. Approximately 855 NRECA members are electric distribution systems. NRECA membership includes other organizations formed by these local utilities:

- 64 generation and transmission cooperatives for power supply
- Statewide and regional trade and service associations
- Supply and manufacturing cooperatives
- Data processing cooperatives
- Employee credit unions

Associate membership is open to equipment manufacturers and distributors, wholesalers, consultants, and other entities that do business with members of the electric cooperative network.

Electric Power Supply Association (EPSA)[265]

EPSA is the national trade association representing competitive power suppliers, including independent power producers, merchant generators, and power marketers. These suppliers, who account for more than a third of the nation's installed generating capacity, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers. Formed as a result of a merger between the National Independent Energy Producers and the Electric Generation Association, EPSA combines the strengths and policy successes of those two prominent organizations on behalf of the competitive power supply industry. EPSA's formation has given the competitive

[264]The material in this section is from NRECA's Website, www.nreca.org.
[265]Information obtained from http://www.epsa.org.

power supply industry the ability to speak with a single, unified voice at the global and national levels.

The Nuclear Energy Institute (NEI)[266]

NEI is the policy organization of the nuclear energy and technologies industry and participates in both the national and global policy-making process. NEI's objective is to ensure the formation of policies that promote the beneficial uses of nuclear energy and technologies in the United States and around the world.

19.3 PUBLIC INTEREST GROUPS

The National Association of Regulatory Utility Commissioners (NARUC)[267]

NARUC is a nonprofit organization founded in 1889. Its members include the governmental agencies that are engaged in the regulation of utilities and carries in the fifty states, the District of Columbia, Puerto Rico, and the Virgin Islands. NARUC's member agencies regulate the activities of telecommunications, energy, and water utilities.

NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Under state law, NARUC's members have the obligation to ensure the establishment and maintenance of such energy utility services as may be required by public convenience and necessity, and to ensure that such services are provided at rates and conditions that are just, reasonable, and nondiscriminatory for all consumers.

Environmental Defense Fund (EDF)[268]

The Environmental Defense Fund was founded in 1967 and is an advocacy group involved in numerous areas. Climate change is one of their main focuses. Presently, they are focusing on nuts-and-bolts policy discussions on how to reduce its impacts.

[266] www.nei.org.
[267] Material from NARUC's Website: www.naruc.org.
[268] http://www.edf.org/home.cfm.

Public Citizen[269]

Public Citizen is a 38-year-old, nonprofit, consumer advocacy group with more than 70,000 members nationwide. Public Citizen's Energy Program promotes clean, safe, and affordable energy, including protections for electricity consumers and enforcement of the Public Utility Holding Company Act of 1935 (PUHCA).

The Energy Program brings cases at FERC and in the courts to preserve the consumer protections of the Federal Power Act and to limit the recreation of the giant utility holding companies. Public Citizen supports full regulation of energy futures markets to restore transparency and limit harmful speculation in natural gas and petroleum prices.

There are a number of state-oriented public interest groups. One example is PULP (see below).

Public Interest Law Project[270]

Formed in New York in the late 1970s, the Public Utility Law Project (PULP) was incorporated in 1981 as an independent not-for-profit organization. PULP's purposes include:

- To educate the public about its legal rights as consumers, and the policies, practices, services, rates, and prices of utilities, regulated businesses, regulatory agencies, and energy corporations, and about energy in general
- To engage in research and to establish a resource center on the legal rights of consumers, and on energy, public utilities, regulated industries, and regulatory agencies
- To provide legal representation, including litigation in the public interest with a primary emphasis on the rights of poor and minority consumers

19.4 RESEARCH ORGANIZATIONS

Years ago, two types of research organizations were founded: one concerned with technical research and one with regulatory research.[271]

[269] www.citizen.org.
[270] www.pilp.tc.
[271] Both EPRI and NRRI were formed at the suggestion of Joseph C. Swidler, former Chairman of the Federal Power Commission.

The Electric Power Research Institute (EPRI)[272]

EPRI was founded in 1973 as a nonprofit energy research consortium for the benefit of utility members, their customers, and society. Its mission is to provide science and technology-based solutions by managing a far-reaching program of scientific research, technology development, and product implementation serving the entire energy industry, from energy conversion to end use, in every region of the world.

EPRI's technical program consists of:

- Power generation
- Distributed resources
- Nuclear
- Environment
- Power delivery and markets

EPRIs programs are open to all organizations involved in the energy industry, encompassing:

- All power utilities, including investor-owned, municipalities, cooperatives, and Federal Government utilities
- Competitive power producers, energy service companies, engineering service companies, natural gas entities, power marketers, manufacturers, industrial companies, and other energy suppliers
- Independent system operators, power exchanges, power scheduling coordinators, transmission companies, distribution companies, and nuclear licensees
- Government organizations involved in funding public-benefit R&D programs

Other Research[273]

Industry-related research is also conducted under the auspices of the DOE, the Empire State Electric Energy Research Corp. (ESEERO), and by numerous universities funded by both the industry and the Federal Government.

[272]Material from EPRI's Website: www.EPRI.com.

[273]Links to many other research organizations can be found at www.netl.doe.gov/weblinks/links.html.

The National Regulatory Research Institute (NRRI)[274]

The NRRI was established by NARUC at The Ohio State University in 1976. It is the official research arm of NARUC and provides "... research and services to inform and advance regulatory policy, primarily for U.S. state public utility commissions."

The NRRI has four programs of regulatory research and assistance: infrastructure, markets, consumers, and commissions. The programs address regulatory policy in the electricity, natural gas, telecommunications, and water industries.

The Power Systems Engineering Research Center (PSERC)[275]

Under the banner of PSERC, multiple U.S. universities are working collaboratively with industry to:

- Engage in forward thinking about future scenarios for the industry and the challenges that might arise from them
- Conduct research for innovative solutions to these challenges using multidisciplinary research expertise in a unique multicampus work environment
- Facilitate interchange of ideas and collaboration among academia, industry, and government on critical industry issues
- Educate the next generation of power industry engineers

PSERC partners with private and public organizations that provide integrated energy services, transmission and distribution services, power system planning, control and oversight, market management services, and public policy development.

[274]Material from NRRI's website, www.nrri.ohio-state.edu.
[275]Material from PSERC's website, http://www.pserc.wisc.edu/about.htm.

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