Chapter 8

Electric Power

Electricity is one of the most widely used forms of energy around the world. US EIA, “Electricity Explained.” The term electricity describes the energy produced when electrons of atoms flow between each other producing a current. NDT, Electrical Current. Unlike primary forms of energy, such as coal, natural gas, oil, or nuclear power, electric power is a secondary source, meaning it is generated by converting primary sources into energy, with fossil fuels generating most of the electrical power in the United States. US EIA, “Electricity Explained.”

According to the EIA’s primary energy consumption by source and sector chart (below), the electric power sector consumed in 2011 about 40% of all primary energy inputs.

EIA, Primary Energy Consumption by Source - 2011
In this chapter, you will learn about:

- Electricity as a secondary source
  - The distinction between primary energy sources and electric power
  - The history of electricity
  - How a modern electric power plant works

- The three-part lifecycle of electric power: generation at a power plant → transmission → distribution to the consumer

- The five types of entities that produce and transport electric power in the United States
  - Investor-owned utilities, federal power agencies, municipal utilities, rural cooperatives, independent power producers, power marketers
  - Antitrust regulation of the electric power market structure

- The basics of the US power grid
  - Nature of the grid: traditional structure and emergence of smart grid
  - Limitation of grid
  - Competition in electric power markets

- The wholesale electric power market
  - The delivery and pricing issues in wholesale markets
  - Price and market regulation by FERC: Order No. 888 and other federal regulations
  - FERC jurisdiction over power marketers
  - New electric power trading markets and mechanisms

- The retail electric market
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Sources:
8.1 Electricity as a Secondary Energy Source

Water power, coal, oil and natural gas are primary energy resources, meaning they are found in nature and may be utilized directly as useable energy. While electricity is also found in nature, it is usually considered a secondary energy resource. Secondary energy sources, also known as energy carriers, move energy in a useable form from one place to another. US EIA, “Energy Explained.” Our ability to harness natural electricity has been limited; thus our electricity comes from the conversion of one of the primary energy sources, water power, coal, oil, natural gas, or nuclear energy. The chart below illustrates the sources of U.S. electricity in 2013:

To understand the significance of the distinction between a primary and secondary energy source, consider a passage from James Trefil’s *A Scientist in the City*:

“Electricity is different from other kinds of energy. When you turn on a light of use an electric tool, you don’t need the source of energy in the same building. In fact, the energy that drives the lights that allow you to read this book was probably generated some tens (if not hundreds) of miles from where you are sitting. Electricity provides a way of separating the generation of energy from its use.”

As a secondary source, electricity is neither considered a renewable or a non-renewable energy source. Energy4Me, Energy Sources. Unlike other industries, electricity requires a constantly available supply to meet demand and the industry must have sufficient and reliable capacity to serve demand instantaneously. To generate and deliver this power, the vast majority of electricity in the United States is provided by local public utilities.
8.1.1 History of Electricity

Electricity is one of our most widely used forms of energy and it was the work of scientists and inventors that deciphered the principles of electricity. Many early cultures were aware of natural electric phenomena, such as static charges, but the term “electricity” is derived from the Latin word, electricus, coined by William Bibert in the early 1600s after his study of electricity and magnetism. Wikipedia, Electricity. Benjamin Franklin furthered the science with his extensive study of electricity, and most famously his eighteenth century kite experiment, which proved the existence of electricity in nature.

The birth of the new electric era of civilization, however, came on October 21, 1879, when Thomas Edison’s light bulb “burned like an evening star.” Edison furthered this new era by championing the use direct current (DC) systems for distribution of electricity to consumers beginning on September 4, 1882 when the Pearl Street Station provided power to 400 incandescent bulbs in lower Manhattan. Despite his strong efforts to make, and keep, DC as the main distribution system in the United States, two shortcomings would ultimately prove fatal to the model. First, DC systems were limited in the range in which they could efficiently distribute electricity, requiring generation of power close to where it was consumed. This would require new power plants to be built to make electricity available in many areas, which turned out to be too costly and impractical for most regions (especially rural regions). Second, DC currents could not easily be converted up or down to higher or lower voltages to, which required separate electrical lines to supply power to appliances that used different voltages. Wikipedia, War of Currents.

Competing against Edison’s DC system was the alternating current (AC), which was championed in the United States by George Westinghouse using the patents of Serbian-American inventor Nikola Tesla. Wikipedia, War of Currents. Power in an AC system is generated by magnets moving back and forth near conducting wires, usually by a turbine, and is capable of being transmitted over long distances using a lower current, which results in lower energy loss and greater efficiency. Further, AC systems are capable of being scaled down to lower voltages for homes and factories. NDT, Alternating Current. The introduction of the rotary converter, which converted AC to DC, along with the unveiling of Tesla’s “City of Light” at the World’s Fair in Chicago began the transition away from DC to the AC systems most cities use today.
8.1.2 Modern Power Station

The modern power station, though an idea of Edison, was fully developed and put into use by one of his lieutenants, Samuel Insull, who assumed the presidency of Chicago Edison Company in 1892. Using the ideas unveiled at the World’s Fair, Insull made Chicago the first or second city to put the rotary converter into use, which allowed him to overcome one of the major issues with central electricity generation. The ability to transmit high voltages through an AC-DC system allowed for a metropolitan area to be composed of fewer, more efficient power plants that feed substations where the electricity was transformed to meet the needs of the particular district.

There was still one other major hurdle for Insull to overcome: the cost to consumers of the electricity. Due to the method of production and distribution of the original central power station, customers with greater electric needs would save money by using self-contained systems, which led to electric companies offering discounts to large consumers at the expense of residential costs. By using a new invention, the demand meter, Insull developed a new two-tier rate structure that reduced costs for both large and small consumers. See Technology as Freedom.

The emergence of long-distance power transmission soon created new regulatory challenges. Many communities and businesses found it cheaper and more efficient to obtain power from a nearby plant in another state. One of the first cases to address this challenge was Public Utilities Comm. of Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927). In the case, the Rhode Island Public Utilities Commission approved an electricity rate increase for all electric utilities in the state, including for sales across state lines into Massachusetts.
Customers in Massachusetts appealed the rate increase, claiming that Rhode Island Commission had no jurisdiction over an interstate sale. The Supreme Court held that because the Rhode Island Commission’s rate increase was “the imposition of a direct burden upon interstate commerce, from which the state is restrained by the force of the commerce clause, it must necessarily fall, regardless of its purpose.” The Court concluded that neither Rhode Island nor Massachusetts had the power to regulate such an interstate transaction and “if such regulation is required it can only be attained by the exercise of the power vested in Congress.” In response, Congress passed the Federal Power Act, which gave to the Federal Power Commission the power to regulate the “sale of electric energy at wholesale in interstate commerce.” 16 U.S.C. § 824.

8.2 How Modern Electric Energy System Works

The physical equipment of a modern electric power system is divided into three basic categories: 1) Generation; 2) Transmission; 3) Distribution. Traditionally, an investor-owned utility or large municipal utilities have owned and operated all three parts, but recently an increasing share of generation facilities are operated by independent power producers. The below graph shows how modern energy systems operate:

8.2.1 Generation

Most electric power plants use coal, oil, natural gas or uranium as fuel for energy generation. Some electric power plants use renewable resources, such as hydroelectric power. Fossil fuels, such as coal, natural gas, and petroleum, generate most U.S. power. US EIA.
“Electricity Explained.” The type of fuel, its cost and generating plant efficiency determines the way a particular generating plant is used. Because demand for electricity will vary significantly in both daily and yearly cycles, a large electric system will usually contain many different types of generating plants and the system operator will try to keep the mix of plants with the lowest operating costs running at any time.

The cost of generating electricity is the largest component of the price of electricity, accounting for 58% of the average US electricity price in 2013. US EIA, “Electricity Explained.” While the vast majority of plants today generate power by burning coal or natural gas, the National Renewable Energy Laboratory has estimated that 80% of fuel sources could be converted to renewable sources without a loss of system reliability. See NREL, Renewable Futures Study. An issue with upgrading older coal plants creates a new problem for generation companies, however, because any major upgrade after 1974 requires the company to meet federal and state requirements for pollution control. Many companies, especially those seeking to upgrade smaller facilities, complain that the costs associated with such upgrades are not worth the upgrades. See WSJ, Upgrade Costs Doom Older Plants. For more regarding companies shifting away from coal, see WSJ, Turning away from Coal.

To determine which type of generating plant will run at a given time, “power plants” are generally classified into four categories:

1. Base load “must run” plants – plants that are mostly nuclear or clean coal, which have low fuel costs and cannot be turned off and on quickly. These units have high capital costs and are operated continuously to meet customer demand.
2. Variable “must run” plants – plants that are mostly water or wind, which have almost no fuel costs but can only operate if enough water/wind is available.
3. Intermediate load plants – plants that are often older coal plants that are costlier than new coal plants to operate. These plants operate to supplement supply when demand increases.
4. Peaking plants – plants that are usually fueled by natural gas or diesel and have higher operating costs but are relatively inexpensive to build and can be taken online or offline quickly.

This balancing among power sources is needed because energy cannot be stored easily. This means that whenever a customer turns power on or off, the generating load must be increased or decreased almost instantaneously to avoid affecting voltage significantly. The most difficult part of the balancing is to have enough base-load generation for constant and assured demand while still having enough peak capacity to meet excess demand at a reasonable cost without having too much excess unused capacity.

Technologies are being developed to better store electricity, but these new technologies are expensive and it will take time for them to become cost-efficient for widespread use. See Environment 360, “The Challenge for Green Energy: How to Store Excess Electricity.”
8.2.2 Transmission

Power plants are large and immovable. While the development of smaller scale power plants may be in our future (such a concept is known within the industry as “distributed generation”), the current model of large, immovable power plant production will remain the paradigm for the foreseeable future. See Wikipedia, “Distributed Generation.” Given this current paradigm, a transmission system can be seen as a substitute for generation expansion because a strong system allows for generating sources (power plants) to transport electricity to the consumer. As utilities expand their transmission resources, and efficiency, there is less of a need to build new generation facilities to meet the demand of customers. The transmission of electricity is accomplished through an interconnected system of lines, distribution centers and control systems.

Transmission lines are commonly “high voltage” lines, with voltages ranging from 69 to 745 kilovolts (kv), which connect high towers along wide rights of way. See Energy Vortex, “Energy Dictionary.” They form a web-like pattern on the landscape with many points of interconnection. Transmission lines in the United States form a network running approximately 160,000 miles. EIA, Electricity Explained. When newly generated electricity is introduced into the network, it will flow in whichever direction the lines are most lightly loaded. Where lines intersect, the electricity will flow through the lines in as even a manner as possible, which means when demand increase on a particular line, generated power will flow to the line to meet the demand. This “loop flow” concept will be further explored later in the chapter.

This transmission network must be operated in a way that keeps the voltage and frequency constant within very narrow limits. The system needs to maintain “operating reserve” in the form generation equipment that can be brought online or offline within around ten minutes. All systems keep a certain ratio of “spinning reserve”, extra generating capacity ready to supply the network if needed, to operating reserve. Most generation systems are designed so that, under normal conditions, the operating reserve is always at least the capacity of the largest generator plus a fraction of the peak load. Wikipedia, Operating Reserve. Operating reserves will also consist of a “non-spinning reserve” that is not currently connected to the system but may be brought online after a short delay and may be power imported from other systems. Wikipedia, Operating Reserve.

The figure below shows an idealized representation of the reserve power system and the time intervals in which they are put into use after an unexpected transmission failure:
Finally, the transmission system needs six identified “ancillary services” identified by FERC to operate properly. “Ancillary services” include “those services to support transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected system.” FERC, *Glossary – Ancillary Services*.

Ancillary services include: scheduling and dispatch, reactive power and voltage control, loss compensation, load following, system protection, and energy imbalance. Wikipedia, *Ancillary Services*. These ancillary services support reliable operation of the transmission system to ensure the transfer of electricity from generation sources to retail customers PJM, *Ancillary Services*.

The transmission lines create an inter-connected grid that helps to attain industry-wide economies of scale and reduce duplication of costs. These economies of scale are further by voluntary arrangements known as power pools, which serve to balance load, realize operating economies. Power pools -- such as the “Pennsylvania, New Jersey, Maryland Interconnection” -- operate throughout the United States. These transmission systems of the United States and Canada are divided into three giant networks:

1. Western Interconnection – begins at the Rocky Mountains and extends throughout the Western United States and Canada. This system is operated by Western Systems Coordinating Council.
2. Texas Interconnection – extends throughout most of Texas and is operated by the Electric Reliability Council of Texas.
3. Eastern Interconnection – extends to the rest of the United States and Canada. This system is not centrally operated but instead is managed by seven separate regional reliability councils.
The North American Electric Reliability Council (NERC) has set standards for the operation of transmission systems in order to regulate the overall reliability of the power grid. NERC was founded by the electric utility industry in 1968 in response to blackouts in the northeastern United States to develop and promote rules and protocols for the reliable operation of the bulk power electric transmission systems of North America. NERC, “Company Overview: Fast Facts.” NERC was appointed by FERC as the Electric Reliability Organization (ERO) for the United States with the legal authority to enforce reliability standards on all owners, operators, and users of the bulk power system.

To regulate the reliable transmission of electricity within a specified area, NERC provides for two related by independent functional entities: the Transmission Operator and the Reliability Coordinator. The Transmission operator is responsible for ensuring the reliability of the transmission assets within a Transmission Operator Area. The Reliability Coordinator maintains operating reliability of the entire Bulk Electric System within a specified Reliability Coordinator area. For information about the specific responsibilities of Reliability Coordinators and Transmission Operators, and the basic model of NERC reliability operations, see NERC, Reliability Functional Model.

### 8.2.3 Distribution

The distribution system in the United States provides retail delivery of power to customers and is primarily in the hands of investor-owned utilities (IOUs), electric cooperatives, and municipal utilities. These utilities distribute electricity to the three classes of customers: residential, commercial, and industrial, with each sector consuming approximately 1 trillion kwh annually. Residential and commercial customers generally use electricity for heating, air conditioning, lighting, refrigeration, and entertainment. In addition to these basic uses, industrial customers primarily use electricity as an energy input.

Distribution systems consist of substations, poles, and wires common to many neighborhoods as well as underground lines found in many areas. The distribution system begins at the substations, where power transmitted on high voltage lines is transformed for delivery low voltage lines in consumer sites. EIA, The U.S. Power Industry Infrastructure. Substations are located at various points throughout the transmission system. These substations contain transformers that reduce the voltage to send the electricity on to the 120-240 volt lines that service homes and businesses. The distribution system also consists of billing customers, reading meters, customer service and many of the common activities that the average person associates with their residential or business’ electrical service. The actual distribution system ends at the consumer’s meter. EIA, The U.S. Power Industry Infrastructure.

Because it would be inefficient and impractical to duplicate distribution lines, the distribution system is considered a “natural monopoly” and is likely to remain a regulated function. EIA, The U.S. Power Industry Infrastructure. The distribution of electric power is an
intrastate function under the jurisdiction of state public utility commissions (PUCs). EIA, The U.S. Power Industry Infrastructure. Retail rates for distribution are set according to PUC ratemaking, considering the cost of the generated or purchased power; the capital costs of the utility; operational and maintenance expenses; costs of PUC mandated programs for consumer protection and energy efficiency; and taxes. EIA, The U.S. Power Industry Infrastructure. 8.3

8.3 Current Structure of the Electric Industry

The electricity industry includes five major entities: (1) Investor-Owned Utilities (IOUs); (2) Federal agencies; (3) Publicly owned systems (“municipals” or “public power”); (4) Rural electric cooperatives; (5) Power marketers. Here are the percentages of utility sales by each entity type.

8.3.1 Investor-Owned Utilities (IOUs)

Although referred to as public entities, an IOU is a private, shareholder-owned company that is a commercial, for-profit utility. Energy Vortex, “Energy Dictionary.” IOUs serve more than two-thirds of the United States population and account for roughly three-quarters of all utilities generation and capacity. EIA, The U.S. Electric Power Industry Infrastructure; Energy Vortex, Energy Dictionary. These IOUs may be small, serving only a couple of thousand customers, or giant, such as multistate corporations that serve millions of customers. The larger IOUs are usually vertically integrated, owning all the generation, transmission and distribution systems. IOUs are found in every state except Nebraska. The major characteristics of IOUs, as defined by the EIA are:

- IOUs must earn a return for investors, which may either be distributed to stockholders as dividends or reinvested in the corporation;
- Are generally granted service monopolies in specified service areas;
- Have an obligation to serve and provide reliable electric power for consumers;
• Are regulated by both State and Federal governments, who approves rates to allow for a fair rate of return for the utility;

• Most are operating companies that provide basic services for generation, transmission, and distribution. EIA, The U.S. Electric Power Industry Infrastructure.

IOUs are normally subject to different regulations than publicly-owned utilities. Energy Vortex, “Energy Dictionary.” IOUs local operations are highly regulated by State PUCs, which includes the setting of retail rates. The IOU will sell power at the rates set by the PUCs to all classes of consumers, but also may sale electricty at wholesale rates to all other types of utilities. EIA, The U.S. Electric Power Industry Infrastructure. IOUs’ wholesale power sales and power transmission contracts fall under the jurisdiction of the Federal Regulatory Energy Commission (FERC), which oversees regulation of the wholesale sale of electricity and transmission of electricity in interstate commerce. FERC, “Overview of FERC.”

8.3.2 Federally Owned Utilities

The Federal Government produces hydroelectric power, primarily as a wholesaler, through nine federally owned utilities. Such utilities operate in all areas of the United States except the Northeast, the upper Midwest, and Hawaii. Examples of federal entities in the electric power industry include facilities owned by the US Army Corps of Engineers and the Tennessee Valley Authority, which is the largest federal producer of power. See TVA & US ACE. While the Federal facilities primarily produce electricity for the wholesale market, power from these facilities also is consumed by large industrial consumers and Federal installations. EIA, The U.S. Electric Power Industry Infrastructure. The Federal utilities service areas are:

Key characteristics of Federally owned utilities are:
• Power is not generated by the utility for profit;

• Power is primarily produced for the wholesale market;

• In the wholesale market, publicly owned utilities, cooperatives, and other nonprofit entities are given preference in purchasing before IOUs;

• Electricity generated by these utilities is marketed by the Federal Power marketing administrations in the U.S. Department of energy; EIA, The U.S. Electric Power Industry Infrastructure.

As of 2013, Federal utilities represented less than 1 percent of all electric utilities and approximately 6.9 percent of all generating capability. Publicpower.org. While power is not sold for profit, the utilities are still responsible for charging a sufficient amount to cover the amount borrowed from the Treasury to construct the facility and the rates must be submitted to FERC to prove rate is sufficient to cover these costs. EIA, Electric Power Industry Overview 2007. Jurisdiction over federal power systems operations and the rates charged to their customers is established in the various authorizing legislation in 16 U.S.C. 12 (2012). See 16 U.S.C. 12 (2012) – Federal Regulation and Development of Power.

8.3.3 Public (Municipal) Utilities

Public power utilities are not-for-profit electric systems owned and operated by the people they serve through a local or state government. American Public Power Association, “Frequently Asked Questions.” There are more than 2,000 public power systems throughout the United States, including local, municipal, state, and regional public power systems that range in size from tiny municipal distribution companies to giant systems like the Los Angeles Department of Water and Power. The Los Angeles Department of Water and Power is the largest municipally owned system, serving 1.4 million customers.

Public utilities, which represent about 61 percent of electric utilities, supply approximately 10.3 percent of generating capability, and 9.8 percent of generation in the United States. Publicpower.org. Public power districts are concentrated in Nebraska, Washington, Oregon, and California. EIA, Electric Power Industry Overview 2007. The major characteristics of public utilities are:

• Established to provide service to their service areas at cost, with a portion of the income generated returned to consumers in the form of a general funds transfer

• Rates are often lower than neighboring IOUs;

• Most do not provide generation or transmission services, but rather only offer a distribution network; and

• Are capable of financing construction of facilities through low-cost, tax exempt debt. EIA, The U.S. Electric Power Industry Infrastructure.
Usually, voters in public utilities districts elect commissioners to govern the district independently of any municipal government, while some utilities, such as the New York Power Authority (NYPA) and the South Carolina Public Service Authority (Santee Cooper) are agencies within the state government. Electric Power Industry Overview 2007. Some states instead create joint municipal action agencies for the purpose of constructing power plants and purchasing wholesale power for resale to municipal distribution utilities. Electric Power Industry Overview 2007.

8.3.4 Rural Electric Cooperatives

Electric cooperatives are electric systems that are owned by their members, the consumers they serve, and each member has one vote to elect the board of directors for the cooperative. Distribution cooperatives provide retail electric service to their members, while generation and transmission cooperatives provide wholesale power and transmission service to their member, distribution cooperative. EIA, Electric Power Industry Overview 2007. As of 2013, there were 871 operational cooperatives in 47 states, which represented about 26.5 percent of U.S. electric utilities and around 5 percent of generation and generating capacity. Publicpower.org. The major characteristics of cooperative electric utilities are:

- Owned by members, usually rural consumers of the cooperative;
- Service is provided only to members;
- Incorporated under State law and directed by an elected board of directors;
- Rates are set similarly to public utilities and service is provided at cost;
- Net margins earned by cooperatives are considered contributions of equity by members and is required to be returned to members as dictated by the bylaws. EIA, The U.S. Electric Power Industry Infrastructure.

Cooperatives generally service areas which where historically viewed as unprofitable areas by IOUs because of the relatively low number of customers per line-mile. EIA, Electric Power Industry Overview 2007. The Rural Electrification Act of 1936, 7 USC § 901 et seq., created the Rural Electrification Administration (“REA”) to electrify rural areas. The effect of this Act can be seen today. In the early 1930s, 90% of rural households did not have electric service. Today, only 1% of rural households do not have electric service.

8.3.5 Power Marketers

Since the passage of the Energy Policy Act of 1992, many new companies have been created to serve as marketers and brokers of electric energy. See US EIA, “Energy Policy Act of 1992.” These entities are classified as utilities because they buy and sell electricity at the wholesale and retail levels. EIA, The U.S. Electric Power Industry Infrastructure. There are currently hundreds of power marketing companies operating in the United States, including four
federal power marketing administrations operated by the Department of Energy that market power generated by federally owned utilities. PLC, Power Marketer Authorization. For more on Federal power marketing administrations, see AllGov, Power Marketing Administrations. The major characteristics of power marketers are:

- Some may be utility-affiliated while others are independently owned;
- Buy and sell electricity; and
- Do not own or operate generation, transmission, of distribution facilities. EIA, The U.S. Electric Power Industry Infrastructure.

Some companies, such as Google, have resorted to creating subsidiaries that have filed with FERC to become power marketers, for the purpose of containing and managing the cost of energy to the company. See Infoworld, Google applies to become electricity marketer.

As opposed to brokers, power marketers take ownership of the electricity and are involved in interstate trade. FERC, Glossary – Power Marketer. Acting as a middle-man in the electric market, marketers offer two main advantages to buyers. First, because the marketer lacks generation assets, they are able to search the market to find the best pricing for clients to reduce the average total cost. Second, because future power prices can vary significantly, power marketers give clients the ability to manage risk through use of derivative products, such as options, swaps, futures, and forward contracts. Spiewak, Why Use Power Marketers?

All power marketers must file with FERC to obtain power market authorization. FERC, Glossary – Power Marketer. To obtain this authorization, power marketers must, among other things, make a proper filing under § 205 of the Federal Power Act and demonstrate to FERC that it lack horizontal and vertical market power, which is the ability of a trader to significantly control the price of electricity by withholding production, liming service, or reducing purchases. PLC, Power Marketer Authorization. A power can demonstrate lack of market power through a declaratory statement that neither the marketer nor its affiliates own or control generation facilities or have a franchised service area. If the power marketer does own or control generation or transmission facilities, it is required to perform a market dominance study. FERC, FAQs – Power Marketers.

8.3.6 Independent Power Producers

Independent power producers (IPPs), or non-utility generators (NUGs), are often privately held facilities that generates electric power for sale to utilities and end users. EIA, The U.S. Electric Power Industry Infrastructure. These entities began to emerge as a result of the Public Utility Regulatory Policies Act of 1978, 16 USC § 2601 et seq., (PURPA), which was prompted by national security concerns resulting from the first Arab Oil Embargo. See Energy.Gov, “Public Utility Regulatory Policies Act of 1978.” PURPA required these
independent power producers to purchase electric power from certain qualifying facilities (QFs). PURPA prohibited facilities from owning a majority share of QFs.

The National Energy Policy Act of 1992 (EPACT) further facilitated the growth of these independent power producers by increasing competition and unraveling the vertical integration of many utilities to lower electric costs. NIPPC, *Introduction to Independent Power Producers*. Under the EPACT, not all IPPs must be qualified under PURPA to operate, however, qualification entitles the IPP to have all of their output purchased by utilities at a guaranteed rate, usually the avoided cost, or marginal cost, of the utility. NIPPC, *Introduction to Independent Power Producers*. In 2002, ten years after the passage of the EPACT, IPPs accounted for roughly one-third of the nation’s power-plants. NIPPC, *Introduction to Independent Power Producers*.

IPPs are most often classified in categories based on their classification by FERC according to the type of technology they employ. There are five major FERC classifications:

1. Cogenerators – Electricity is generated sequentially with another power source, like heat, from a single fuel source. These entities are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria and their output entities is guaranteed to be purchased by utilities at a price based on the utility’s “avoided cost” and will provide back-up service at nondiscriminatory rates.

2. Small Power Producers – Use biomass, waster, renewable source, or geothermal as the primary energy source and fossil fuel is allowed to only account for 25 percent of energy input. These entities are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria and their output entities is guaranteed to be purchased by utilities at a price based on the utility’s “avoided cost” and will provide back-up service at nondiscriminatory rates.

3. Exempt Wholesale Generators – Created by the EPACT and exempt from corporate and restrictions of the Public Utility Holding Company Act. See Wikipedia, *Public Utility Holding Company Act of 1935*. These wholesale facilities cannot participate in retail markets and may not possess significant transmission facilities. Utilities are not required to purchase electricity generated by these entities and they are regulated, but are usually able to charge market rates.

4. Congenerators (Non-QF) – these generators are not qualified under PURPA and utilize cogenerator technology to generate energy, some of which they may consume themselves.

5. Noncogenerators (Non-QF) – are not qualified under the provisions of PURPA and do not utilize cogenerating technology. EIA, *The U.S. Electric Power Industry Infrastructure*. 

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As many state commissions encouraged these independent producers to bid on major generation projects, and as these producers could often underbid traditional utilities, such entities became more and more common. By allowing competition between utilities and IPPs for projects, costs for electric power are borne by private investors and allow a reduced cost of energy to be passed on to ratepayers. NIPPC, *Introduction to Independent Power Producers*. As of 2002, it is estimated the increased competition created by the EPACT reduced the cost of electric power by 35 percent. NIPPC, *Introduction to Independent Power Producers*. Further, IPPs have led the way in incorporating more efficient forms of generation, such as thermal electric conversion fired with natural gas, and have even commercialized wind energy. NIPPC, *Introduction to Independent Power Producers*. For more on the ability of IPPs to use green energy, see below.

### 8.3.7 Antitrust Law and Regulating Market Power

Electricity suppliers have been regulated as public utilities on the assumption that a “natural monopoly” exists in the industry. However, the availability of alternative energy sources (e.g. oil and natural gas) and competition between different electricity suppliers, have created a certain amount of competition in the market. Nevertheless, the potential for anticompetitive behavior by electricity suppliers sometimes makes antitrust regulation relevant.

Antitrust laws are primarily designed to protect competition from monopolistic behavior. In *Otter Tail Power v. United States* (US 1973), the defendant, Otter Tail Power, was accused of violating the Sherman Act by refusing to sell and transmit power to local municipalities. The Court found that Otter Tail used its monopoly power to foreclose competition, gain a competitive advantage, and destroy a competitor, all in violation of antitrust law. It held that the Federal Power Act, upon which Otter Tail relied, does the opposite of exempting electricity suppliers from antitrust legislation; instead it has an “overriding policy of maintaining competition to the maximum extent possible consistent with the public interest.” Otter Tail was therefore liable under the Sherman Act. See 15 USC § 1 et seq.

Electricity firms however, may not always be subject to antitrust regulation. When an enterprise’s competitive activities are scrutinized under a particular regulatory scheme, courts will defer to such a scheme, rather than apply antitrust laws. Courts will not defer to the regulatory scheme if it is not directly concerned with the anticompetitive implications of firms in the industry.

The relationship between investor-owned utilities, municipal utilities and federal agencies has also led to jurisdictional conflicts. In *FPC v. Southern California Edison*, 376 U.S. 205 (1964), the Supreme Court held that the FPC had plenary jurisdiction “extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.” This expanded the scope of federal regulation beyond the *Attleboro* decision discussed above.
In *FPC v. Florida Power & Light Co.*, 404 U.S. 453 (1972), the Supreme Court further expanded the scope of federal regulation. In the case, all of the generation and transmission facilities of the Florida Power and Light Company were located within the state of Florida, and none of the facilities were connected directly with out-of-state utilities, customers or power sources. The FPC claimed jurisdiction over FP&L on the theory that some of the utility’s electrons entered the Georgia market because FP&L’s transmission lines connected with another Florida utility that connected to Georgia. The Court upheld the FPC’s jurisdiction stating, “the elusive nature of electrons renders experimental evidence that might draw the fine distinctions in this case practically unobtainable.” Therefore, FP&L could not prove with certainty that none of their elections crossed state boundaries.

### 8.4 Evolution of Electric Power

The evolution of the generation, transmission, and consumption of electricity into the future will be guided by changes in the regulatory landscape, economic markets, environmental trends, and available technologies. The emergence of wholesale and retail electricity markets in a deregulated commercial environment is one important development, and is discussed later in this chapter. Another key trend is the research and implementation of smart grid technologies, which can revolutionize the transmission and conservation of electricity. Finally, climate change and the reduction of carbon emissions will radically alter the way electricity is generated over time.

#### 8.4.1 Smart Grids

Electrical grids were originally designed to be unidirectional networks of generators connected to consumers by transmission systems. This arrangement emerged as a result of several factors. When electricity was initially generated for the purpose of consumption, plants were isolated and served dedicated customers. In part, this was because the cost of building and generating electricity was high and significant economies of scale were needed for producers to realize a profit. Additionally, the infrastructure to transmit electricity over large distances simply did not exist. Over time, geographically proximate electrical providers consolidated to form the forerunners of modern utility companies. This [website](#) provides greater detail on the rise of the modern electrical grid.

Currently, the electrical grid used in the United States is an interregional network, where generated electricity is either consumed nearby or exported to other regions depending on several factors, including the prevailing costs of generation, demand, and external market forces. However, there are limitations to the grid as it presently exists. First, renewable and cleaner sources of energy function differently than traditional fossil fuel generators. While the negative environmental effects of renewable energy technologies are significantly reduced compared to carbon-fueled generation, those cleaner sources are more unreliable. For instance, solar cells capture the energy produced by the light of the sun and convert it into electrical energy.
However, solar cells cannot produce electricity at night, or when the sun is obscured by clouds and intervening objects. Wind power captured by turbines can only provide electricity when the wind is blowing. The implication of these examples is that the current grid cannot effectively harness renewable energy sources without some means of capturing and storing the energy they generate for consumption later when those sources are not actively generating power. This paper discusses the integration problem in further detail.

Another shortfall of the present grid is that consumers are unable to effectively conserve and utilize electricity because of information asymmetry. For example, in the household electricity market in the U.S., homes are typically equipped with an electricity meter that measures the amount of electricity consumed within that particular structure. However, those meters tend to be installed on the exterior of the building where consumption decisions are not made (though convenient for monitoring by the utility providing the electricity). Furthermore, the meters do not provide the consumer any information about the cost of the electricity being consumed. The price of electricity varies over time according to the demand and seasonal factors. For instance, electrical consumption peaks during the middle of the day in the summer because households are typically running air-conditioning devices. Conversely, winter peak hours tend to be early in the morning and late at night as heating devices are used mostly at those times. This utility company website explains one such breakdown of peak and off-peak electrical usage.

A third major drawback to the present electrical grid is its vulnerability to outside attack and natural disasters. Given the current disposition of the grid, generation and transmission of electricity tend to be concentrated upstream. This concentration means that a focused attack by terrorists or another nation can adversely affect a disproportionately large segment of the population. Furthermore, earthquakes and other natural disasters of local effect can have a devastating impact on a regional power grid. This blog summarizes some of the key vulnerabilities of the U.S. electrical grid and the stance of the Department of Defense towards the issue.

One approach to addressing the drawbacks of the current electrical grid is through the implementation of a “smart grid.” The term “smart grid” encompasses more than mere transmission of electricity; it is a concept which embraces radical changes to the way electricity is generated, transmitted, and consumed along the entire value chain. First, smart grids incorporate a variety of energy sources and possess the means to integrate renewable and nonrenewable power plants. Second, smart grids provide information to producers, consumers, and regulators to provide opportunities for efficiency, cost reduction, and conservation. Third, smart grids represent physical upgrades to the electrical grid that improve reliability and provide for the multidirectional flow of energy. This primer published by the U.S. Department of Energy provides a good overview of the key concepts of a smart grid.
Smart grids are capable of integrating energy produced from any source, and allowing that energy to be tapped in any number of ways. Large-scale power plants and small wind farms can ideally be accessed and harnessed by a smart grid at the same basic cost and level of efficiency. Furthermore, a smart grid possesses the means to store energy for later consumption. Storage can ameliorate the difficulties posed by the variability of solar, wind, and hydrokinetic energies, and additionally allow consumers the opportunity to better manage the times at which energy is consumed. Finally, smart grids allow for energy to be put into the grid at any point along the value chain. Consequently, a household might place solar panels on the roof of a home or install a small-scale wind farm on its property to generate power for itself and to be put back into the grid. This Australian white paper discusses the ways in which the integration problem can be addressed in a smart grid.

Information is an important and powerful tool. Currently, producers and consumers of electricity are blind to the means by which that electricity arrives at the point of consumption. Electric utilities still routinely dispatch “meter readers” who go from home to home recording and reporting the amount of electricity consumed. A smart grid instantly reports this data to electric utilities for billing purposes. Furthermore, a smart grid notifies the consumer of the rate and costs of consumption on a real-time basis so that better informed decisions can be made regarding when and to what extent electricity should be used. Finally, smart grids provide system-wide intelligence to governments and utilities for the purpose of assessing the health of the grid, the supply of electricity, and its usage at any given moment. This information allows policymakers and industry to better address changes in the grid and allocate resources effectively. The Department of Energy’s Advanced Modeling Grid Research Program is one such effort to better understand grid dynamics.

The reliability of the electrical grid has a direct impact on safety, economic productivity, and quality of life. Smart grids improve the reliability of electrical power through the use of improved hardware, flexible means to reroute the flow of electricity, and better information available to the producers of energy. For instance, automatic switchable networks combine multidirectional flows of electricity through the grid with software capable of analyzing and presenting decision makers with the feasibility of varying contingency plans depending on the availability, cost, and demand of electricity. These networks effectively lower the cost to provide electricity by allocating it across the grid in the most economic possible manner at any given point in time. One effort to implement this aspect of the smart grid is the North American SynchroPhasor Initiative, which seeks to apply a uniform method of measuring grid activity along with hardware to take the measurements.

The technology required to successfully implement a full smart grid is in varying stages of maturity. However, the question of whether smart grids will exist is not so much a matter of “if,” but rather “when.” The U.S. has legislated a Smart Grid policy and offered matching federal funds to offset smart grid investment costs. 42 U.S.C. §§ 17381-86. As the cost of these improvements is decreased over time, the move towards a smart grid that provides cheaper,
efficient, reliable electricity will depend upon the collaboration of government, industry, and consumers of energy.

### 8.4.2 Competition in Electric Power

Traditionally, electric power was considered a public utility; a vertically integrated monopoly in a given geographic location would provide generation, transmission, and distribution services. Under this traditional understanding, regulation was based solely on cost-of-service. Cost-of-service is “the amount of revenue a regulated gas pipeline company must collect from rates charged consumers to recover the cost of doing business.” [FERC Cost-of-Service Rates Manual](https://www.ferc.gov). However, due to bad investments and the need for additional flexibility in the regulatory process, federal policy has begun to shift to promoting competition within the industry. FERC’s core responsibility now is to “guard the consumer from exploitation by non-competitive electric power companies.” While FERC’s goal has always been to find the best combination of regulation and competition, it has recently begun to shift the balance towards the side of competition.

There are two reasons why the electric power market has become deregulated and thus more competitive. First, the sale of electricity simply is not a natural monopoly. A natural monopoly is a situation where for technical or social reasons there cannot be more than one efficient provider of a good, i.e. public utilities. [About.com, “Definition of Natural Monopoly.”](https://www.about.com) Federal policy makers have taken the position that the electric power market should be an industry in which sellers compete for customers. Second, markets are able to set electricity prices more efficiently than governments can, because markets tend to be more dynamic and responsive to supply and demand.

The shift towards a more competitive market has helped create our current system, dominated by state-chartered, vertically integrated, investor-owned utilities (IOUs), which provide monopoly electric service within their designated service areas. This system however is limited by the obligation of universal service and limits on the sale price of electricity. It is also criticized for its inefficiency and asymmetry of information, as regulators are forced to depend on regulated firms for cost information.

Advocates of deregulation generally have seven goals as the market becomes more competitive: 1) lower prices for consumers; 2) diversification of firms in the industry; 3) increased flexibility in firm investments; 4) increased adaptability to technological change; 5) increased efficiencies; 6) diversification of risk; and 7) increased accountability and decreased reliance on government. Barriers to these goals, some argue, are inherent to the natural structure of the electric utility. That is, deregulation might have the effect of giving utilities too much power which may, in turn, lead to increased prices, decreased competition, and less accountability. *The False Promise of Electricity Deregulation.*
Growth of Wholesale Competition in Electric Generation. How would increased competition in the electricity generation affect prices? A 1997 report by the U.S. Energy Information Administration (EIA) concluded that full-scale competition would reduce rates 6 to 13% within two years. According to the EIA, under conditions of intense competition, prices could fall as much as 24 percent. However, the study noted, there would be significant differences in different states. Not only had Congress intended to diversify electric generation sources and create greater competition among utilities, but Congress also wanted to reduce reliance on petroleum. Indeed, “[t]he basic purpose of § 210 of PURPA was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels.” Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp. Given these purposes, the Supreme Court found that, in the implementation of PURPA, it was appropriate for Congress to incentivize the development of small power producers. Such incentives helped lead to the growth of independent power producers.

PURPA and Independent Power Producers (“IPPs”). As electricity prices rose in the 1970s and 1980s, due to increased oil prices and more stringent environmental standards, pressure increased to create more competition in the electric market. In response, in 1978 Congress adopted the Public Utilities Regulatory Policy Act (PURPA), 16 USC § 2601 et seq., the first endorsement by Congress of a more competitive electric industry. PURPA began the deconstruction of the traditional structure of regulation by allowing FERC to create rules encouraging new entrants, known as “qualifying facilities” (QFs), to participate in electric generation. It authorized FERC to require utilities to purchase or sell electricity to new entrants, thus allowing for monopolies to be broken up. Some of these new entrants “were pioneering renewable-energy technologies . . . [which had] not been able to produce electricity at the (relatively) low cost that utilities [could] achieve.” Qualifying Facilities Under PURPA: What Qualifies? These rules were challenged, but upheld by the Supreme Court. See FERC v. Mississippi, 456 U.S. 742 (1982).

Market-Based Rates and Other Reforms to Rate Regulation. With increased competition, federal regulators have taken two approaches to move away from the traditional structure: 1) market based rates; and 2) incentive rates.

Market-based rates are established through competitive bidding or through negotiation between the buyer and seller, rather than set by a regulator. US Dept. of the Interior Bureau of Reclamation, “Glossary.” In the 1980s, FERC approved market-based rates for independent power producers that lacked significant market power, relieving these generators of the burdens of cost of service regulation, and exercised “light-handed” regulation for independent power producers, in order to lower costs.

In analyzing whether an electricity generator’s rates are reasonable as market-based rates, courts will look at whether 1) the seller or any of its affiliates is a dominate firms in the sale of generation services in the market; 2) the seller or its affiliates owns or controls transmission
facilities which could by used by the buyer; and 3) the seller or any of its affiliates is able to erect or other control any other barrier to entry. Dartmouth Power Associates Limited Partnership, 53 FERC ¶ 61, 117 (1990).

While most utilities with market power continue to base rates on cost of service, in 1992 incentive rate systems emerged as an alternative. Incentive rates attempt to lower rates to consumers and increase shareholder returns. Incentive regulation programs provide financial rewards or penalties based upon the utility’s performance. Such performance is based on criteria set by state utility commissions and include low heat rates (which reflects high efficiency) or purchased power at below-average prices. An Evaluation of Incentive Regulation for Electric Utilities. “Formal comprehensive incentive regulation mechanism have been slow to spread in the U.S. electric power industry, though rate freezes, rate case moratoria, price cap mechanisms and other alternative mechanisms have been adopted in many states, sometimes informally since the mid-1990s. Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks. For more on incentive rates, see FERC. “Transmission Investment.”

8.5 New Wholesale Power Markets

In order to further increase competition in the electric power industry, Congress passed the Energy Policy Act of 1992, which expanded FERC’s authority over wholesale electricity transmission and removed certain restrictions on the growth of the independent power industry. Wholesale electricity is that which is sold to non-consumers, usually a retailer, for resale. 16 U.S.C. § 824(d) defines “sale of electricity at wholesale” simply as the “sale of electric energy to any person for resale.” Electricity originates from a generating station, is transmitted over high-voltage lines (this is wholesale transmission), and is then distributed locally to end-users after the power is stepped down at power substations.

NY ISO, Understanding the Markets
The Energy Policy Act of 1992 allowed FERC to mandate wholesale transmission where it would not result in a “reasonably ascertainable uncompensated economic loss” and would not place “an undue burden,” “unreasonably impair the reliability of any electric utility,” or impair adequate service to customers. This expanded section 211 of the Federal Power Act (FPA), 16 USC § 791 et seq., which bars FERC from requiring wholesale transmission unless it would “preserve existing competitive relationships.” The Act of 1992 therefore opened up access to a broader range of energy providers.

8.5.1 FERC Order 888

In 1996, FERC adopted Order No. 888, which required all public electric utilities to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. FERC, “Order No. 888.” The goal of the order was to remove impediments to competition in the electric marketplace and lower the costs for consumers. FERC, “Order No. 888.” The order also required functional unbundling, requiring each utility to state separate rates for generation, transmission and ancillary services. FERC, “Order No. 888.”

FERC Order No. 888 was issued in order 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.” FERC, “Order No. 888.” The Order therefore required all public utilities involved in interstate commerce to file open access transmission tariffs (OATTs). “Transmission open access provides the ability to make use of existing transmission facilities that are owned by others . . . in order to deliver power to customers.” FERC Order No. 888. Open Access Transmission Tariff Accounting. Filing of the OATTs with FERC allows the Commission to actively monitor the interstate electricity market, including producer market power, price points of electricity, and non-rate terms of transmission. FERC Docket No. RM95-8-000.
In *New York v. FERC* (US 2002), the Supreme Court discussed first, whether a public utility that unbundles—separates the cost of transmission from the cost of electricity when billing customers—will be required to transmit competitors’ electricity over its lines on the same terms that the utility applies to its own energy transmissions, and second, whether FERC may impose that requirement on utilities that continue to offer only bundled retail sales. The court answered “yes” to the first question, and “no” to the second. The court upheld both FERC’s assertion of jurisdiction under section 201 of the FPA and its ability to implement Order No. 888. It held that FERC has the authority to regulate wholesale transmission because of its determination that functional unbundling was necessary to remedy discrimination in the wholesale electricity market.

### 8.5.2 Implementing Open Access for Wholesale Transmission

An important feature of Order No. 888 is that it requires each utility under the jurisdiction of FERC to file an open access tariff. This tariff is subject to the approval of FERC after submission. The tariff lays out the terms and conditions for access to wholesale transmission. Usually, the utility and FERC will agree upon the price of such transmission; however, many regional utilities’ prices are set by Regional Transmission Organizations (RTOs). RTO’s, by FERC mandate, are 1) independent (i.e., they operate independently from market participants), 2) “serve a region of sufficient scope and configuration to permit it to maintain reliability, effectively perform its required functions, and support efficient and nondiscriminatory power
markets,” and 3) have “exclusive authority for maintaining the short-term reliability of the grid.” FERC Order No. 2000-A. Finally, RTOs are the sole providers of transmission services and sole administrators of their respective open access tariffs, and they are required to manage congestion within the wholesale transmission network. FERC Order No. 2000-A.

Unlike natural gas, the transmission of electricity does not require the use of valves. While the technology exists to limit and stop the flow of electricity, use of such technology should be cautioned. If not monitored and controlled efficiently and carefully, there is a high risk of sacrificing reliable service. Thus, it is important to determine where the optimum locations of these control devices so that service remains uninterrupted. Because electrons flow in the past of least resistance, it is possible for a transmission that appears to be between New York and New Jersey to use transmission lines through other states, like North Carolina, even though these states do not lie in the direct linear path between the generator and the customer. Such physical diversions in the transmission of electricity are called “loop flows.” See Understanding Loop Flows.

Loop flows are, by their definition, not the most efficient method of transmission. Before the transition to a competitive market, vertically integrated companies could manage these loop flows with cooperative mechanisms. However, since deregulation, loop flows have been a growing concern since a simple market model, such as the model used in natural gas (where the consumer could negotiate directly with the pipelines), will likely be problematic where transmission capacity constraints lead to large and constantly changing congestion costs.

To remedy this problem, FERC has looked to Independent Service Operators (ISOs) to ensure reliability in the transmission of electricity. ISOs manage the transmission of electricity over specific regions of the country. This management provides open and equal access to all electricity buyers and sellers. ISOs will be responsible for the reliability and security of the transmission system and could provide maintenance of the overall structure. While utilities are not required to have an ISO, FERC’s standards for approval encourage such plans.

Despite these responsibilities inherent to an ISO, ISO’s still enjoy less direct accountability to FERC than do RTO’s. For a discussion of the differences between RTO’s and ISO’s, see the PJM Learning Center and ISO-RTO.
Due to the constantly changing supply and demand of the electricity market, supply and purchase arrangements are not isolated. Another barrier to reliability is that some remote areas of the country have little access to mediums of transmission. To remedy this problem, FERC proposed a Standard Market Design (SMD) for pricing transmission across the entire country. See FindLaw, “Detailed Summary of FERC’s Standard Market Design NOPR.” FERC’s SMD model received significant opposition and it was abandoned. Had FERC continued to pursue SMD, and perhaps why it abandoned its efforts, there would have been deep federalism implications (asserting federal jurisdiction over state retail transmission) and upset tradition balances of merchant and utility-owned generator power (anathema to state regulators in the Southeast). See Gridlock. Nevertheless, FERC is still interested in maintaining stable prices across the varying markets.

One example of why FERC is concerned with price reliability is the Summer of 1998 Heat Wave. See National Climatic Data Center, “Climatic Extremes of the Summer of 1998.” A prolonged heat wave spread across the United States during the summer of 1998 and demand for electricity skyrocketed. A power company in Chicago had not contracted for enough power supply to satisfy this unexpected demand, forcing the company to go to spot markets to buy electricity at 20 times the standard rate. At one point, prices surged to nearly 100 times their normal level. On the other side of the negotiations, companies like Enron made millions of
dollars by selling electricity, doubling its revenue of 5.86 billion dollars and generating 241 million dollars in income.

![Billion Dollar Weather/Climate Disasters graph](image)

**Graph: National Oceanic and Atmospheric Administration**

In a report on these events, FERC issued a report that acknowledged that the market system would have highs and lows, depending on demand. Some people criticized FERC’s reaction, claiming that there should be more regulation to prevent such problems in the future. Others claimed that the market reacted exactly as it should have, and the markets are developing just as many markets do: they learn as they evolve.

### 8.5.4 FERC’s Jurisdiction over Power Marketers

Traditionally, electric power generators sold the power that they generated directly to the consumer. The shift from a non-competitive, monopolistic system to a market-driven one gave rise to independent ‘power marketers.’ These power marketers typically do not own transmission or generation facilities; they instead purchase and resell energy generated by others. As discussed below, the rise of power marketers came with benefits, drawbacks, and regulatory needs. In October of 1985, Citizen’s Energy filed a petition to FERC seeking approval to purchase and resell electricity. Two years later, Howell Gas Management submitted its own petition asking for the same privileges. It was not until 1989 that FERC approved a petition to buy and sell. This approval signaled that FERC recognized a new type of company in the wholesale market: a power marketer. See [PMA Online Magazine, “Why Use Power Marketers?”](#)
A power marketer buys electricity and services that support the transmission of electricity and resells these products and services at a higher price in order to make a profit. While it may seem counterintuitive, many believe that the rise of power marketers will result in cheaper energy prices for the consumer. Additionally, power marketers can provide consumers more stable prices that are not subject to variation as a result of generation costs. PMA Online Magazine, “Why Use Power Marketers?” These types of companies have grown in tandem with the growth of the deregulated wholesale market. Power marketers exist in varying forms, including gas marketers, brokers, financial firms, utility affiliates, entrepreneurs, commodity traders, and independent power producers. While these firms vary in size, some power marketers have become powerhouses in the wholesale market. At one point Enron, Lewis Dreyfus, and Electric Clearinghouse accounted for 57% of sales.

Power marketers can easily manipulate markets. For example, as mentioned in Chapter 2 of this Wikibook, Enron was a significant player in the California Energy Crisis. A FERC investigation uncovered Enron’s manipulation of the power market in California and other states. See FERC, “Initial Decision.” Enron was eventually ordered to refund more than $32 million in unjust profits.

In 2005, Congress passed the Energy Policy Act, 42 USC § 13201 et seq. See EPA, “Summary of the Energy Policy Act.” The Act made significant changes to federal jurisdiction over electric power transmission and enforcement of reliability standards. These additional powers include “back stop authority,” which allows FERC to order the acquisition and rights-of-way to provide mediums of transmission through the nation’s electricity corridors. The Act also amended the FPA to provide FERC the power to certify an Electric Reliability Organization (ERO) to help reliability standards. On July 20, 2006 the North American Electric Reliability Corporation (NERC) was designated as the ERO and assumed the following responsibilities:

- An obligation to maintain independence from users, owners and operators of the bulk power system while assuring fair stakeholder representation on its board of directors
- The right to charge and collect fees, dues and charges from end user to pay the ERO’s administrative costs
- A duty to promulgate reliability standards after notice and opportunity to public comments subject to FERC approval
- The authority to impose penalties for violations of reliability standards, also subject to FERC review.

The Energy Policy Act also gave FERC jurisdiction over all users, owners, and operators of the “bulk power system.” This includes jurisdiction over power marketers, traditional utilities, and other producers otherwise not subject to FERC’s jurisdiction. Prior to FERC’s designation as the ERO, compliance with its guidelines was encouraged but ultimately voluntary. Following its designation as the ERO, its standards became compulsory and if any users, owners, or operators
are found to be in violation of the ERO reliability standard, FERC is authorized to penalize the violator up to $1 million per day, and possible criminal penalties and jail sentences are available. (For the list of standards, see FERC: Reliability Standards). If a regional entity meets the same standards as the ERO, it may delegate the ERO’s responsibilities to that entity. See 18 CFR § 39.8, “Delegation to a Regional Entity.”

8.5.5 Evolution of Electricity Trading Mechanisms

Lately, there has been a development of sophisticated trading mechanisms that facilitate the trading of electricity on commodity markets. These mechanisms allow electricity to be traded along the same lines as petroleum and natural gas. This flexibility allows electricity to be sold at market centers at market-based rates.

One of these electricity trading mechanisms is the electricity future contract. In an electricity future contract, parties agree to buy or sell a specified amount of electricity at a set rate at a particular time in the future. Another of these mechanisms is the electricity option contract. In this sort of contract, a party purchases the right to buy or sell a certain quantity of electricity at a set price. Electricity Trading in Competitive Power Market.

Electric energy trading poses particular risks not found in other commodity markets, One of the largest of these risks arises from the fact that electricity is essentially non-storable. This means that the energy must be generated at the time it is going to be consumed. Electric energy trading is also impacted by transmission constraints. Unlike natural gas and petroleum which can be piped or shipped across countries and oceans, the laws of physics limit the distance that electricity can be transported. Electricity Trading in Competitive Power Market.

8.6 Retail Competition in Electric Power

8.6.1 History and Rationale of Retail Restructuring

Beginning in the 1990s after passage of the Environmental Protection Act, new calls were made for deregulation of the retail energy markets. See EPA, “National Environmental Policy Act.” Politicians and economists spurred the movement for deregulation seeking to introduce competition to the energy markets in order to lower rates and ensure better service. They used as their model the deregulation of the natural gas industry. One of the spurs for reform was the fact that some states had high power costs, and thus they hoped competition would lower prices by allowing a more dynamic market. Much of the discussion in this section parallels closely to the discussion of state Public Service Commissions and their efforts to deregulate and open up for competition discussed in an earlier chapter. State PSCs took the lead in designing and implementing retail competition because of their authority over retail rates, local distribution, and construction of power plants (as opposed to FERC leading the effort on a national scale). The movement began with the idea for “retail wheeling,” which allowed direct access to electricity supply markets for large retail customers, but the movement shifted to comprehensive
efforts to implement “retail competition.” Retail competition encompassed many aspects of energy transmission and pricing such as customer protection and stranded cost recovery. This allowed consumers to deal with more than one company in the various aspects of energy consumption instead of dealing head on with just one company. Under the hypothetical retail competition regime, states maintain regulatory control over some aspects of energy consumption, while leaving other aspects to markets, meaning that true deregulation was not accomplished.

In a competitive retail market, the incumbent distribution utility, known as the “DisCo,” continues to operate as a regulated natural monopoly. See Energy Central, “Energy Central Glossary - DisCo.” However, competitors are allowed to use the DisCo’s distribution network so that consumers can choose the company that provides their energy.

Proponents of restructuring claimed that it would lead to less expensive power for consumers, choices of electricity suppliers (including allowing “green energy suppliers” greater access to customers and vice versa), and innovations in generation and transmission grid technologies that would be stifled by a traditionally regulated energy environment.

Restructuring has not occurred uniformly throughout the country. In some regions, such as the South, the West, and the lower Midwest, restructuring was slower because those regions have larger utility companies and thus can create economies of scale where energy is typically cheaper. Also, state regulatory environments vary by region, which can cause variations in the price of energy and thus incentives or disincentives for restructuring. Finally, access to subsidized energy, like areas powered by the Bonneville Power Administration and the Tennessee Valley Authority, affected the price of energy. All of these factors affected a push for restructuring in areas of higher energy prices -- the Northeast, California, and upper Midwest -- while places with lower energy prices -- the South, lower Midwest, and Northwest -- resisted efforts at restructuring.

One serious policy implication of restructuring was the continued role of consumer protection. How can regulators assure that consumers’ rights are being protected when there is more than one energy provider at work in an area and thus no single company is tasked with ensuring equal service to all customers? State PSCs have had to address this question and change the way they operate on customers’ behalf.

Other policy concerns deal with similar aspects of market competition and their effects on consumers and prices. How would market mechanisms control supply and demand for the most essential commodity (electricity)? Would retail rates decrease or would consumers be vulnerable to price spikes in a restructured market? How would markets be structured so that participants would not take advantage of consumers? Would price signals from the market be sufficiently clear to encourage the appropriate level of investment in generation and transmission? Or would it be more likely that the current group of generators would be encouraged to limit capacity growth and instead maximize current profits?
The previously monopolistic utilities also faced concerns in a newly competitive market. They feared they would not be able to recover investments made under the assumption of continuous state regulation of their activities. They demanded that these “stranded costs” be accounted for.

8.6.2 Common Features of Restructuring Plans

By 2010, fourteen states and D.C. had restructured their retail electricity markets. Another eight states had suspended or repealed their restructuring laws as a result of the California electricity crisis of 2000-01. Restructuring plans were as diverse as the states themselves, but most addressed the following issues.

Choice of alternate provider. Retail electricity customers in most states have their choice of electricity generators but no choice of distribution utility. In Texas, customers choose a retail energy provider that selects the generators and sells electricity to retail consumers.

Standard offer or default service (plus customer protections). The “duty to serve” has evolved with the dawn of competitive energy markets, so states have adopted different ways to protect customers who choose to stay with the incumbent electricity providers. Such methods of protection include: (a) the incumbent utility continues to provide service under a rate that essentially passes through the utility’s wholesale cost of power; (b) the utility remains a service provider to some customers but not to others; (c) the utility continues to provide service but does so under a rate structure designed to gradually wean customers away from utility service and towards market-based prices; (d) the privilege of serving non-choosing customers is bid out while the utility’s role is to deliver power.

Stranded costs. Stranded costs are the costs of investments made by utilities that assumed they had an indefinite window of time as the utility provider to make long-term investments. Wikipedia, “Stranded Costs.” The traditional system of regulation and monopoly protected electric utilities. This meant that they could set their prices high enough to recover their costs and earn a reasonable rate of return without fear of being undercut. As the electric energy market is restructured to a market-based, competitive system, the utilities lose the protections afforded to them by the traditional system. As competition enters the market and prices drop, the value of the electric utilities’ assets will erode, leaving some of their costs and investments ‘stranded.’ It is estimated that the amount of stranded costs in the U.S. is more than $100 billion. These stranded costs raise a number of regulatory and policy issues. Electric Utilities: Deregulation and Stranded Costs.

There are four basic types of stranded costs: ‘(1) undepreciated investments in power plants that are more expensive than generators today. (2) Long-term contracts – most if not all mandated by the 1978 Public Utilities Regulatory Policies Act (PURPA). (3) Generators built but not used, primarily nuclear. (4) Expenses related to demand-side management (“DSM”) and other conservation programs that, as substitutes for new plant construction, were chaged to the
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Utility companies believe that they should be compensated for these stranded costs. They argue that they incurred these costs by serving the public interest under a particular regulatory regime, and that it is unfair to penalize them when this regulatory regime changes. They also argue that they made certain investments that they would not have made had they known that they would be forced to operate in a restructured market. Additionally, some of these investments came about as a result of pressure from regulators and federal or state governments. Electric Utilities: Deregulation and Stranded Costs.

Consumer groups do not believe that utility companies should be compensated for these stranded costs. Their argument is based on a number of premises: 1), there is no regulatory compact, so utilities are not entitled to compensation; 2) investors have long been aware that serious losses or bankruptcy were possible in the electric utility industry without hope of compensation; 3) electric utility investors have for many years been compensated at levels sufficient to cover the risk of some loss of their strandable investment; 4) not all strandable commitments were prudently incurred; 5) compensation would delay the benefits of competition from reaching consumers; 6) utility restructuring has been on the way for a long time and utility companies should have been prepared; 7) other utilities have experienced deregulation and survived. Electric Utilities: Deregulation and Stranded Costs

To deal with this problem, most states established a “competitive transition charge” that customers would pay the incumbent utilities to cover stranded costs for some amount of time. These CTCs (also known as wire charges) are nonbypassable charges imposed on every utility customer for a transitional period of time. In addition to CTCs, some states allow stranded cost recovery to be securitized -- where the utility’s right to receive future competition transition charges could be converted into a current, fully vested property right that could be pledged or sold as security for the issuance of transition bonds. This raised a whole new set of concerns pertaining to the trading of securities of a public utility.

Consumer rate protections. Many state restructuring plans promised consumers rate reductions or attempted to hold residential consumers harmless. These resulted from the recognition that retail markets would not be established immediately, and addressed the risk that retail markets might not serve to lower prices. In response to these concerns, many states instituted rate caps on electricity providers. However, these caps dampened the demand for a competitive market because consumers were discouraged from switching to another energy provider if the incumbent provided promised locked-in low rates. These rate caps were often designed to expire once the state had completed the transition to full competition. Once the caps expired, residential consumers of electricity often saw their electricity rates increase by 20-50%. Rate Cap Fact Sheet.
Other consumer protections. Many states sought to police the retail markets by setting up systems to protect consumers from abusive behavior by energy marketers. The abuses that were feared parallel two that are common in competitive telecommunications markets; ‘slamming’ and ‘cramming.’ Slamming is the illegal practice of changing the type of service the customer receives without authorization. FCC: Slamming. Cramming is the illegal practice of placing unauthorized, misleading, or deceptive charges on the customer’s bill. FCC: Cramming. While such practices are not common in the utility industry, states nevertheless felt the need to put specific protections in place.

One type of consumer protection takes the form of electricity marketer licensing, and the Maine Public Utilities Commission’s (MPUC) scheme presents a typical example of this sort of licensing framework. To obtain the required license under this scheme, the electricity marketer ‘must show evidence of financial capability, demonstrate that they could enter into binding interconnection agreements with utilities that would transmit and distribute their power, disclose all pending legal actions or consumer complaints from the previous year, and disclose names of affiliates.’ Additionally, the licensed marketer cannot disconnect service without thirty days’ notice and cannot call customers who have made written ‘do not call’ requests. Should an electricity marketer violate the terms of its license, MPUC can revoke its license and impose penalties of up to $5,000 a day for each violation.

System benefits charges. Many states feared that electric utility restructuring would negatively impact some ‘public benefits’ found in a non-competitive, monopolistic system. As a result, these states imposed ‘system benefit charges’ on each energy consumer as a condition of restructuring. These system benefit charges were designed to ensure that market-driven utilities would continue to research and develop renewable energy sources, provide assistance for low-income consumers, and promote energy efficiency. Electric Utility Restructuring and the Low Income Consumer.

Exit fees and switching penalties. If too many customers switch to the competitive market from the incumbent utility, this could affect reliable distribution and the rate charged to the remaining customers. States addressed this problem by assessing exit fees (also to compensate for stranded costs) if a customer left the utility, or penalty fees if a customer switched providers too often. Other states required minimum period of use of the chosen provider.

While sound in theory, exit fees raise a number of issues. Given the nature of the electric energy market, the reduction in load caused by an individual leaving the incumbent utility may not result in any increase in cost or reduction in reliability of distribution. States are beginning to examine this issue when structuring their exit fee systems. Another issue raised by exit fees is the fact that some energy consumers may move outside the utility’s distribution system (e.g. a residential consumer that moves from one region to another). In this case assessing an exit fee would not serve its deterrent purpose, EPA: Utility Fact Rates Sheet.
Functional separation and divestiture. States often required that utilities separate the generation function of their businesses from the transmission and distribution functions to prohibit self-dealing and thus prevent abuse of market power by utilities. If a utility is allowed to merge its production and transmission costs, it could raise its transmission prices in order to artificially lower its generation costs. Allowing a company to offset its generation costs by inflating its transmission costs has a number of negative effects:

- Transmission will be overpriced, which may result in underutilization of the transmission system.
- Generation will be underpriced, which my result in overutilization of the generation system.
- The owner of the transmission system will have an unfair advantage over other generators, since the other generators cannot subsidize their generation with inflated transmission revenues.
- The utility may reduce its transmission system maintenance expenditures in order to offset generation costs, resulting in reduced transmission reliability.

The separation of electric energy utilities takes two forms: functional separation and divestiture. In a system of functional separation, both the transmission and generation processes are owned by the same company. The separation is accomplished by requiring that the company have a separate employee organization and accounting process for its transmission and generation arms. Functional separation is relatively easy to accomplish since the company can simply separate its generation and transmission departments into nominally independent divisions. The major drawback of functional separation is that it will be difficult to ensure that the company is not merging costs between its generation and transmission divisions.

Divestiture prohibits a single company from owning both the generation and transmission processes. Divestiture is more difficult to accomplish, since it requires that original company be split into two completely independent companies. This raises a number of issues, including assigning the assets and liabilities of the original company among the two new companies. The major benefit of divestiture is that the independent companies that result would have no financial incentive to collude. Why Separate Utilities?

8.6.3 Status of Common Law “Duty to Serve”

The advent of a competitive market for energy brought with it the risk that, with many energy providers, no providers would carry the “duty to serve” that traditional utilities carried (such as with the PSC discussion earlier in the book). While customers have the option of switching from provider to provider, thus perhaps eviscerating the need for the duty to serve, those customers of little means might find themselves without adequate service. This represents
the most serious of policy concerns – with a commodity as vital as energy, who bears the role of guaranteeing service to all members of the public? This represents the clash between consumers’ ability to choose the most efficient electricity services and the broader goal of allocating society’s resources efficiently (ensuring all members of society have access to vital resources like energy).

### 8.6.4 Examples: State Restructuring

The approaches taken by states in restructuring their electric retail markets have been as varied as the states themselves. The text below describes the approaches taken by three states in particular: Pennsylvania, Texas, and California.

**Pennsylvania.** Pennsylvania was one of the first states to implement a retail competition plan. This effort was spurred by Pennsylvania’s status as the state with one of the highest energy rates in the country in the mid-1990s. Proponents of restructuring hoped energy prices would drop by as much as 25% if restructuring were enacted. Pennsylvania enacted a plan that maintained protections for customers who chose not to switch, such as rate caps. A large percentage of Pennsylvania consumers initially switched to the retail market. However, within five years of the initiation of the retail market, the vast majority of consumers had switched back to one of the incumbent utilities. Even after the expiration of the rate caps, the public utilities were able to drop their rates to compete with or beat the new energy competitors.

In contravention to the argument that the Pennsylvania rate caps dampened the market for energy competition is the concept that the market system was not introduced to destroy the public utilities but instead to provide an alternative to people who wanted another service or who sought more green alternatives, for example.

**Texas.** Texas initiated its retail energy market in 1999, with it becoming fully operational in 2007. Texas’s plan included a “price to beat” (PTB) that served as the benchmark below which the incumbent provider could not go as to encourage competition. At a later period in the transition, the PTB also served as a ceiling above which energy prices could not go to ensure consumers had some access to affordable energy. The law also required a utility to act as the utility of last resort for customers who could not afford the market’s price or for customers whose energy provider went out of business. Texas’s market continues today, however the higher prices brought about by deregulation continues to be debated. [Texas Coalition for Affordable Power](https://www.texascoalition.org)

**California.** California also had high energy prices in the early 1990s. Pressure for lower prices, especially from industrial users, led to California’s move towards a competitive retail market. In 1996, California enacted a law to move the state’s energy resources toward a market-based system. The bill required state-chartered, non-profit institutions to manage and operate the electrical grid (ISO) and supervise the electricity exchange (CalPX) where buyers and sellers would auction energy to maximize price efficiency. The law required private and public utilities
to allow ISO to control their electricity transmission facilities.

Unfortunately for California, a series of worst-case scenarios hit the state in 2000 and 2001, when the competitive retail market was coming on line. The sudden skyrocketing of electricity prices (caused by increased demand, lack of output, increase in natural gas prices, and flaws in the CalPX system) combined with illegal market manipulation by unscrupulous energy companies led to devastating blackouts, a shortage of power, and unsustainably high electricity prices. This combination of factors caused California’s transition to a competitive retail market to be put on hold.

8.6.5 Future of State Restructuring

Electric industry deregulation and restructuring has seen some successes and many failures over the last two decades. The jury is still out on the best solution moving forward, and different commentators have varying opinions on the matter. The failures of California’s system provide a warning of mistakes not to make again. Some aspects of Pennsylvania’s and Texas’s systems provide guideposts for future steps. Proponents of competitive retail markets argue that it takes time for markets to mature and ripen. Others suggest that unbundling, arms length transactions, and deregulation in a unique market like electricity create market inefficiencies of their own.

Traditional monopolistic regulation, though it has its merits, would benefit from reform even if states do not embrace the market-oriented reform method. Ultimately, to maximize efficiency in pricing, usage, and distribution, politicians will have to acknowledge and reconcile the two competing factors at play in electricity production: (1) market efficiency cannot be achieved if politicians intervene to protect consumers from price increases caused by energy scarcity and (2) vulnerable customers cannot be subjected to unaffordable energy costs. Until these factors are reconciled, market volatility will continue, and energy users may prefer the safety of a regulated but expensive market to the uncertainty of a still-forming energy market.