TEXAS PUBLIC POLICY FOUNDATION

A Primer on Electricity

Technology, Regulation, and Markets

December 2006

By Robert Michaels
California State University, Fullerton

Table of Contents

About the Texas Public Policy Foundation

The Texas Public Policy Foundation is a 501(c)3 non-profit, non-partisan research institute guided by the core principles of individual liberty, personal responsibility, private property rights, free markets, and limited government.

The Foundation's mission is to lead the nation in public policy issues by using Texas as a model for reform. We seek to improve Texas by generating academically sound research and data on state issues, and recommending the findings to policymakers, opinion leaders, the media, and general public.

The work of the Foundation is primarily conducted by staff analysts under the auspices of issue-based policy centers. Their work is supplemented by academics from across Texas and the nation.

Funded by hundreds of individuals, foundations, and corporations, the Foundation does not accept government funds or contributions to influence the outcomes of its research.

The public is demanding a different direction for their government, and the Texas Public Policy Foundation is providing the ideas that enable policymakers to chart that new course.

A Primer on Electricity

Technology, Regulation, and Markets

Robert Michaels
California State University, Fullerton

RR 04-2006

Permission to reprint in whole or in part is hereby granted, provided that the Texas Public Policy Foundation is properly cited.
Copyright ©2006 by the Texas Public Policy Foundation, Austin, Texas.

A Primer on Electricity

Technology, Regulation, and Markets

by Robert Michaels

Executive Summary

Few revolutions in history stand out so prominently as the electrification of the planet. Electricity transformed the machine age and became the foundation of the information age, as a once-undependable novelty became a necessity of life and commerce. Among the best measures of a nation's welfare are its production and consumption of power.

As of today, 19 states and the District of Columbia allow retail customers access to competitive suppliers. Texas has moved the fastest and furthest toward successfully providing consumer choice in the electric market, and is almost alone in its continuing rise in loads of all types that have switched away from utility service. While Texas leads the nation, many other states have faltered and given up on these efforts.

Electricity's move to the market has been complicated by both technological, economic, and political factors. An electric system is very capital intensive and some of its most important facilities, particularly transmission, may require a significant amount of centralized control. Any markets that are formed must take into account the realities of the industry's structure, which is particularly complex in America.

Nevertheless, competition—particularly at wholesale—has grown, in part because of FERC policy and in part because of legislation that authorized FERC to take a more active role in ensuring nondiscriminatory access to transmission by wholesale producers, consumers, and marketers. At the state level some programs that allow retail choice, like California's, are moribund and the promise of others like Pennsylvania's is vanishing as flaws in its underlying legislation become apparent. Texas, however, has had a near uniform record of success at instituting competition in both its wholesale and retail markets.

Electricity has always been an important public policy issue. Because of the complexity of the electric markets and related public policy, this paper—the first in a series—is a primer on electricity providing a foundation for our examination in future papers of the successes and challenges in the move toward deregulation in Texas electric markets.

Introduction

Few revolutions in history stand out so prominently as the electrification of the planet. Electricity transformed the machine age and became the foundation of the information age, as a once-undependable novelty became a necessity of life and commerce. Among the best measures of a nation's welfare are its production and consumption of power. Around the world, the interactions of private enterprise and public policy have produced a remarkably diverse set of electricity industries. Government-owned Électricité de France is a near-total monopoly, but one known for its innovation in nuclear technology and its efforts to institute economically efficient power pricing. Japan and the United States are characterized by large corporate utilities with exclusive territories and regulated rates, but the U.S. also has over 2,000 utilities operated by local governments and nonprofit cooperatives. Almost everywhere, electricity is moving to the market. Nations with governmentally-operated systems are moving toward privatization, and those with regulated systems are introducing competition into power production and consumer supply. State governments in the U.S. regulate most power sales to final consumers, and they are moving forward to the market at different rates. Texas has moved the fastest and furthest in that direction.

Electricity is used in virtually every home and business (homes use approximately one-third of all delivered power), and there are few readily available substitutes for it in most applications.

Electricity has always been an important public policy issue. There are various aspects of this issue that are especially relevant for Texas, including:

Size

Over the twentieth century the U.S. came to consume more energy per capita than any other nation, and electricity became more important in its energy mix. In 1940, fuels burned to produce electricity accounted for 10 percent of America's energy consumption. By 1970 that figure had reached 25 percent and today it is 40 percent.[1]

Economic Importance

Electricity is used in virtually every home and business (homes use approximately one-third of all delivered power), and there are few readily available substitutes for it in most applications. By any standard it is a major industry. In 2005, $247 billion was spent on delivered power.[2]

Environmental Impact

Nearly two-thirds of America's electricity comes from generators fueled by coal, whose environmental effects require costly remediation, and uranium, which requires provisions to handle spent nuclear fuel. Some policymakers believe that to address international concerns about global warming, energy efficiency must increase substantially so as to reduce power production.

Inadequate Infrastructure

Some parts of the nation are approaching a reliability crisis. Investments in electric transmission fell in every year between 1975 and 1999, from $5 billion (2003 dollars) per year to less than half that amount.[3] That trend has recently reversed itself, but investment in 2004 remained below its 1975

level. Meanwhile, power consumption continues to increase and the emergence of markets for it has further stressed the grid. Today at least 75 percent of power passes through various markets before reaching its final users.[4]

Changing Roles of Government and the Private Sector

Electricity production in many nations is being "restructured" to rely more on competitive markets and less on regulation. Nevertheless, the industry's political environment make some degree of regulation hard to escape. Uncertainty and disagreement about how to best capture the benefits of competition pervade discussions among policymakers, industry figures, and academics.

Texas' Exemption from Important Federal Regulations

Prices in "wholesale" power that will ultimately be resold to final users are federally regulated everywhere in the continental U.S. except in those markets that operate under the auspices of the Electricity Reliability Council of Texas (ERCOT). Most of the state is minimally interconnected with interstate grids, but remains subject to federal policies regarding transmission access and the treatment of independent power producers.

Generation Costs in Texas

The area of Texas where users of power can choose their suppliers consists of most, but not all of the state. Although largely disconnected from other grids, ERCOT's territory contains enough generators and transmission lines to maintain reliability equal to that elsewhere in the country. Electrical isolation leaves the 20 million customers in the competitive area with a mix of generators that is heavily weighted toward natural gas, whose price has recently become unstable. Coal-burning and nuclear plants are possible alternatives, but they face regulatory and political hurdles. Some propose that the state invest in major conservation and demand management programs to limit the need for new power plants.

Consumer Choice in Texas

Currently, the 19 states and the District of Columbia that account for roughly one-third of U.S. power consumption allow households and businesses to choose among competing suppliers.[5] Relative to other states with choice, Texas has been the most successful in terms of consumers exercising choice, the development of competing suppliers, and the impact of competition on prices. Now that the transition to competition is nearly complete, what policies are required to ensure that Texans can continue to enjoy these benefits?

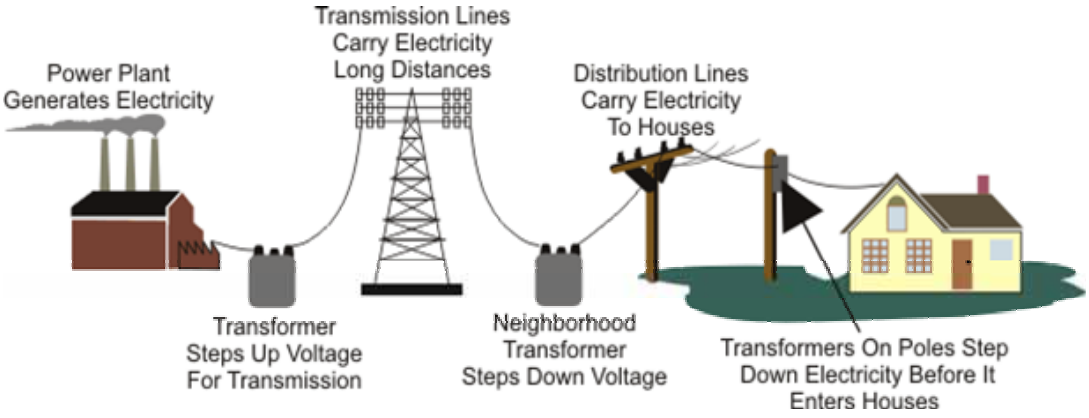
Texas has been the most successful in terms of consumers exercising choice, the development of competing suppliers, and the impact of competition on prices.

Electricity: Its Generation, Transmission, and Distribution

The Basics

Figure 1-1 shows the fundamentals of a typical electric system. On the left a utility is responsible for serving customers in its territory. Before competition a customer's only choice was to take service from the utility at regulated rates. The utility either owns or has arrangements with power plants (generators) which it dispatches to meet changes in demand (its "load"). In addition to operating generators the utility will have units scheduled to come on-line during the peak hours and reserve units in various stages of readiness. A utility that owns generators, high-voltage transmission lines and low-voltage distribution lines is said to be *vertically integrated*. Transformers "step up" the voltage to prepare power for transmission and "step it down" to voltages that small customers can use. This utility in Figure 1-1 also performs customer service. Its employees deal with interruptions in delivery as well as metering, billing, and customer relations.

Figure 1-1
Basics of an Electric Delivery System

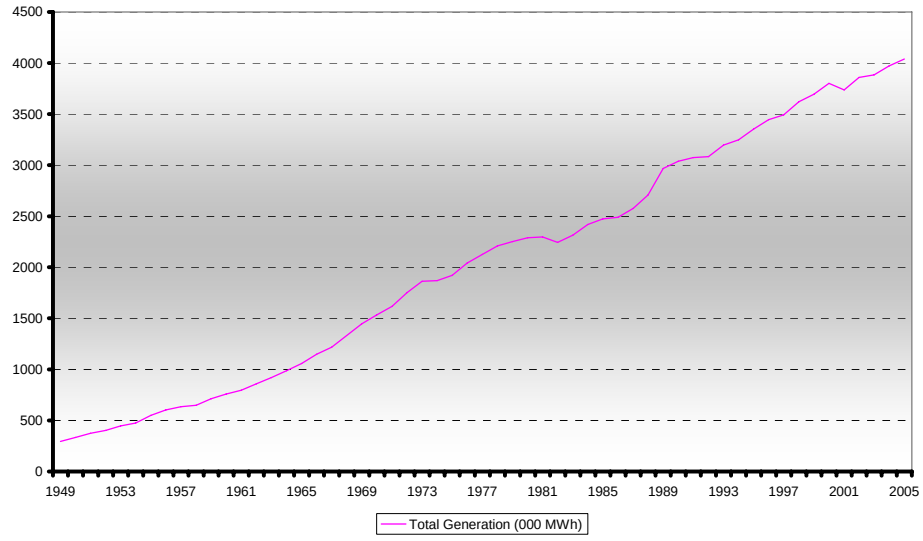


Source: "Electricity Basics 101," Energy Information Administration (EIA), http://eia.doe.gov/basics/electricity_basics.html.

Generation

A generator transforms the energy of fuel or falling water into electrical current. A "thermal" power plant creates high-pressure steam that turns an electromagnetic turbine, inducing an alternating current at 60 Hertz (cycles per second) into the transmission grid.[6] A generator's capacity is measured in megawatts (MW, equal to thousands of kilowatts (KW)), produced in flows of megawatt-hours (MWh).[7] **Figure 1-2** shows the growth of power production in the U.S. from 296 million kwh in 1949 to 4,038 in 2005. Since 1990, production in Texas has risen from 282 million kwh to 390, a higher growth rate than for the U.S. as a whole.[8] Texas consumes more electricity than any other state, 44 percent above runner-up California.

Figure 1-2
Total U.S. Electricity Generation (000 MWh), 1949-2005



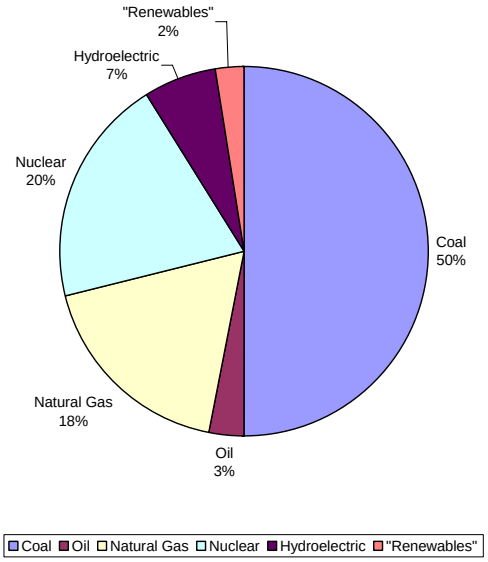
Source: U.S. Department of Energy, Energy Information Administration (EIA), "Electric Power Annual 2005," Op. Cit. Data Tables at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

Since gas and coal account for over 50 percent of delivered power costs from plants that burn them, the rise in gas prices and its increasing instability over the past three years has become a matter of concern.

Electricity is the world's most capital-intensive major industry. Between the 1920s and 1970s, the scale and efficiency of fossil-fueled generators increased steadily, reducing the cost per unit of output. This trend reversed itself in the 1980s. A new 600 MW coal-fired generator inclusive of pollution controls currently costs about $1.7 million per MW.[9] A new 540 MW combined-cycle natural gas-fired plant costs about $540,000 per MW, but has considerably higher operating costs.[10] A new coal-fired unit requires an average of seven years to go from proposal to operation, and a gas-fired one takes about three. Coal and nuclear generators are usually "base-loaded" to operate at all times, while most gas and hydroelectric plants operate only during hours when demand is higher.

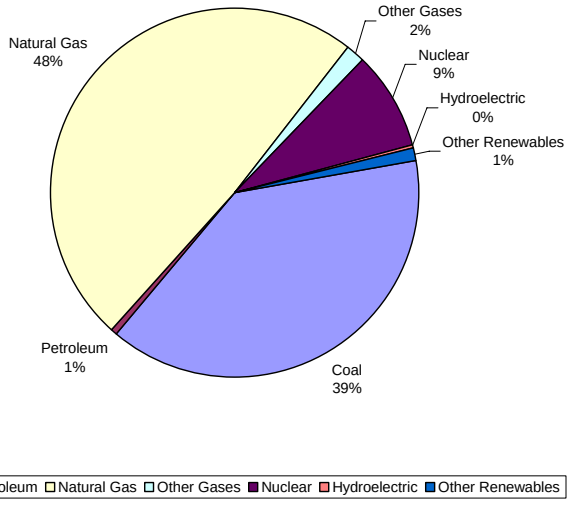
As shown in **Figure 1-3**, the fuel mix of generators has evolved with technology and fuel prices, in both the U.S. and Texas. As of 2004, coal generated 49.7 percent of all power in the U.S., followed by nuclear plants at 19.8 percent, gas at 12.6 percent, hydroelectric at 9.6 percent, and miscellaneous sources accounted for the remainder. "Renewable" power sources, mostly windmills, biomass conversion (agricultural trash burning), and geothermal accounted for only two percent of the total. **Figure 1-4** shows that Texas has a quite different mix of sources, with virtually no hydroelectric power. Gas produced 49 percent of its electricity, coal 39 percent, nuclear 9 percent, and renewables (nearly all wind turbines) only 1 percent.[11] Since gas and coal account for over 50 percent of delivered power costs from plants that burn them, the rise in gas prices and its increasing instability over the past three years has become a matter of concern. Coal prices too have increased but by less, and most coal is purchased under contracts that provide for smaller fluctuations.

Figure 1-3
U.S. Electricity Generation by Energy Source, 2004



Source: U.S. Department of Energy, Energy Information Administration (EIA), "Electric Power Annual 2004," Table 1.1, http://eia.doe.gov/cneaf/electricity/epa/epax1file1_1.xls.

Figure 1-4
Texas Electricity Generation by Source, 2003



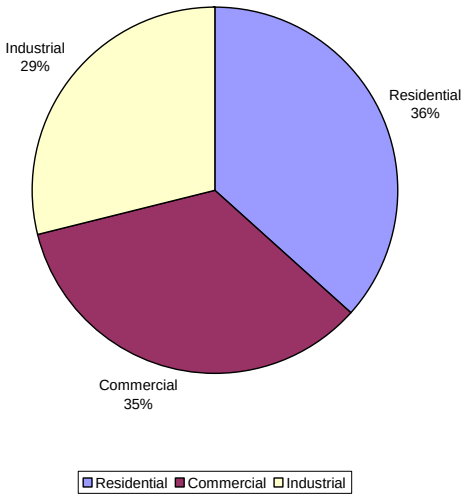
Source: U.S. Department of Energy, Energy Information Administration (EIA), "Electric Power Annual 2004," Table 1.1, http://eia.doe.gov/cneaf/electricity/epa/epax1file1_1.xls.

Transmission and Distribution

High-voltage transmission lines move power from distant generators, and low-voltage distribution systems deliver it to users. The U.S. contains 637,000 circuit-miles of lines capable of carrying power at 110 kilovolts (thousand volts, or KV) or above, the definitional breakpoint between transmission and distribution facilities.[12] The highest voltages currently in operation are 765 KV. The amount of power a line can carry increases far more than proportionately with its voltage—a 100-mile long 230 KV line (the "backbone" transmission in most metropolitan areas) can carry 265 MW, but a 345 KV line over that distance has a capacity of 860 MW.[13] The economies of scale in transmission are even more pronounced than these figures suggest. Construction costs per mile increase less than proportionately with a line's voltage, and a smaller fraction of a large line's power is lost in transit due to resistance.[14] Reliability considerations aside, a single line is the cheapest way to deliver power. As we will see, this need not imply that the line's owner produce the power it carries. Corporate utilities own 73 percent of the nation's transmission lines, the federal government owns 13 percent, and municipal and cooperative utilities own the remainder.[15]

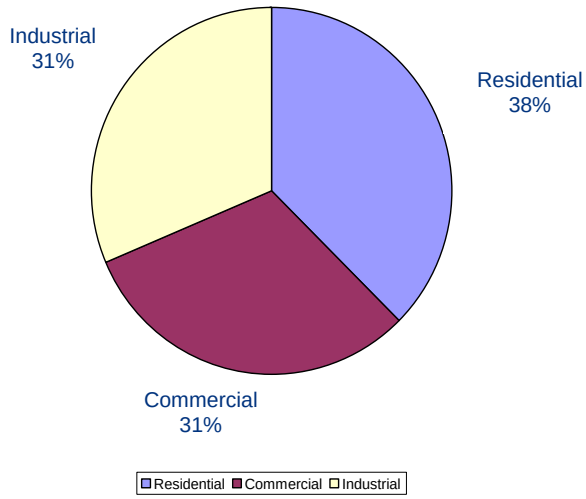
Distribution of power to final consumers is known as retail service. **Figure 1-5** shows that residential customers in the U.S. consumed 34.8 percent of delivered power in 2004, commercial establishments 33.1 percent and industrial plants 27.4 percent.[16] **Figure 1-6** shows comparable figures for Texas. Most localized distribution grids that deliver power to final customers operate under regulated rates and terms of service. Duplicated low-voltage lines are viewed as redundant and unattractive by local governments, so most distribution utilities have monopoly franchises and legal obligations to serve all customers in their territories.

Figure 1-5
U.S. Percentage of KWH Consumed by Customer Type, 2004



Source: U.S. Department of Energy, Energy Information Administration (EIA), "Electric Power Annual 2005, Op. Cit., Table 7.2, http://www.eia.doe.gov/cneaf/electricity/epa/epax1file7_2.xls.

Figure 1-6
Texas Percent of KWH Consumption by Customer Type, 2004

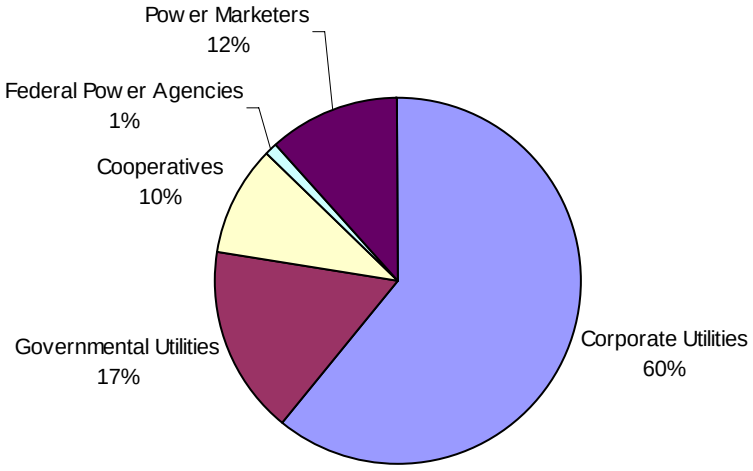


Source: U.S. Department of Energy, Energy Information Administration (EIA), "Electric Power Annual 2005, Op. Cit., Table 7.2, http://www.eia.doe.gov/cneaf/electricity/epa/epax1file7_2.xls.

History has given the U.S. a mix of electric providers unlike any other nation's, consisting of corporations, governmental entities, and nonprofit associations.

History has given the U.S. a mix of electric providers unlike any other nation's, consisting of corporations, governmental entities, and nonprofit associations. Their shares of sales are shown in **Figure 1-7**.

Figure 1-7
2004 Percentage of Retail Power Sales by Supplier Type



Source: American Public Power Association, U.S. Electric Utility Industry Statistics, 2004. http://www.appanet.org/files/PDFs/2006StatCharts.pdf.

In 2004, the distribution arms of 220 corporate utilities accounted for 60 percent of the industry's sales revenue, 2,011 governmental utilities (municipalities and special districts) accounted for 17 percent, and 884 cooperatives accounted for 10 percent. Nearly all of the remainder was sold by power marketers (rather than utilities) to retail customers in states that allowed them to seek competitive supplies. Sixty percent of those sales took place in Texas.[17] In 2001 (the last year before retail customer choice changed the nature of electricity service), Texas contained six corporate utilities, whose customers used 198.4 million kwh of electricity, 63.0 percent of the state total.[18] Eighty-seven municipal utilities delivered 87.9 mkwh (27.9 percent) to their customers, and 62 cooperatives delivered 28.7 of them (9.1 percent).[19] By May of 2006, 56 percent of power consumed in ERCOT territory was sold by non-utility marketers.[20]

Technology and Operations

Electricity is a unique commodity, or perhaps it is a service. Most users value reliability very highly, and also wish to enjoy the option of changing their consumption of it without notifying their suppliers. To satisfy these desires the operator of an electricity system must have reserve generators operating at all times, ready to instantly change output in order to meet changes in demand or unexpected outages of other generators or transmission lines. Most U.S. systems strive for a reserve margin (operating and ready to operate) of approximately 18 percent of peak load, but this figure has been falling as markets become more dependable sources of power. A mismatch between inflows into the transmission network from generators and outflows to users (load or demand) as short as one second can black out a large region, regardless of whether demand exceeds supply or falls short of it. With minor exceptions like pumped hydroelectric storage, economically important amounts of electricity cannot be stored. Over a day, a region's late afternoon peak demand can be as much as twice its pre-dawn minimum, requiring the system's operator to choose an efficient mix of generators to operate at different times of day, and to have others in readiness to meet unexpected conditions. A human operator (or in some regions, a market) determines the roster of available generators, and computers adjust their outputs so that production remains in balance with load.

Electricity is a unique commodity, or perhaps it is a service. Most users value reliability very highly, and also wish to enjoy the option of changing their consumption of it without notifying their suppliers.

Prior to the coming of power markets in the 1980s, these network properties and scale economies were major determinants of the industry's organization. They strongly favored regional operation by vertically integrated entities. Many small municipal systems operated as "requirements" customers of corporate utilities, purchasing some or all of their power for resale to local residents and businesses. To maintain reliable operation, an electric grid is best broken up into control areas where generating units are controlled and operated from a central location to match the demand for power instantaneously with generation sources.

Even if one operator controls all of a region's facilities, the physics of electricity adds its own unique difficulties. Power cannot be directed to flow along a single alternating current (AC) line like water or gas in a pipe. Instead it moves over an entire grid, with more of it flowing along paths that have lower resis-

tances. If these flows threaten to overload a line, the best way to reduce the hazard may seem at variance with economic principles—the grid operator may need to operate a high-cost generator at one location while leaving a low-cost one elsewhere idle. Lines affected by these so-called "loop" or "parallel" flows need not be directly connected to a producer or purchaser. Only about half the power sold by an Oregon generator to a California buyer will move along the Pacific coast. The rest gets there via lines in Utah and New Mexico, where unexpected flows can threaten reliability and raise operating costs.

Electricity and Government

State Regulation

Electricity also often operates under a unique regulatory regime that controls the rates and terms of service that power suppliers must offer.

On matters like labor relations and safety, governments regulate electricity producers and distributors in the same ways they do other firms. Because electric generation is by far the nation's largest coal consumer, it is particularly affected by environmental regulation. Electricity's unattractive transmission lines often make it a target of pressure groups intent on seeing that new facilities are not built, or that they at least be less obtrusive. Electricity also often operates under a unique regulatory regime that controls the rates and terms of service that power suppliers must offer. Some regulations are federal and others come from the states. Tensions between them have risen with the opening of markets.

Commercial electricity began in 1882 when Thomas Edison started serving 85 customers from the Pearl Street generating station in lower Manhattan. By the early twentieth century his direct current (DC) technology had been superseded by alternating current (AC), which could cover wider areas with more complex and reliable grids. Because the delivery of electricity required rights-of-way and easements, local governments soon began issuing franchises that gave individual utilities rights to serve and exclude other suppliers, in return for tax revenues. The spread of electricity to unincorporated areas and the extortionate behavior of local governments toward franchised utilities combined to move much of the regulation of electricity to state governments. Beginning with Wisconsin and New York in 1907, newly invented public utility commissions allocated larger and more permanent service territories to utilities and instituted standardized regulatory procedures. Regulators gave utilities obligations to serve all customers in their assigned territories at rates that recovered their costs and offered investors returns that were sufficient to attract capital. Both politics and technology favored self-sufficient, vertically integrated utilities that invested in transmission and generation to anticipate load growth. Regulation spread over the nation during the twentieth century. Texas was the last state to get a public utility commission, in 1975.

The regulation of retail electric rates remains little changed since its inception. In a "general rate case," a utility presents cost and demand data to justify a "revenue requirement" that meets its expected expenses, inclusive of returns that will attract investors to its stock and bonds. It then estimates the costs of serving customers with different load patterns and proposes rates that will meet

its revenue requirement. Industrial customers with steady loads can fully utilize baseload generation that runs all the time, while service to residential and commercial customers with high afternoon and evening use requires "peaking" plants that may operate for only a few hours of the year. Not surprisingly, representatives of the various customer classes (as well as environmentalists and public interest groups) often testify in rate cases. Since some of the utility's most important costs are common to many customers (a transmission line carries power for all of them), allocating them is usually the most contentious aspect of a regulatory proceeding. Regulators have the power to disallow from rate recovery utility expenses that they find "imprudent," but only on rare occasions like the nuclear powerplant overruns of the 1980s have they done so on a large scale. However, some smaller expenses are routinely denied as a rate case proceeds.

These "cost of service" proceedings can have perverse effects. Regulators allow the utility to earn a return on its "rate base," the cost of its facilities net of depreciation. Setting the allowed rate of return can involve rather arbitrary calculations in which a fraction of a percentage point may mean millions of dollars in customer bills. The system gives utility managements some odd incentives, because the more that a utility spends on rate base the higher is its income. In other industries competition usually suffices to restrain managements from spending imprudently, but utilities are franchised monopolies with regulated rates. The coming of power markets (described below) has replaced some state regulation, but in other areas the scope of that regulation is growing. As power prices rise, regulators have become more responsible for assistance to low-income customers. Currently in twenty states they are responsible for enforcing "renewable portfolio standards" that direct utilities to purchase certain environmentally benign resources that they might not otherwise have chosen and allow them to pass the costs on to consumers. In some states decisions about new powerplants and transmission have been taken out of utilities' hands and given to regulators who administer "Integrated Resource Planning" proceedings. Nominally an attempt to determine how to meet future power demands (including possible reductions in use) at least cost, IRP has often turned into a forum for interest groups whose outcomes have had little economic rationality.

The regulation of retail electric rates remains little changed since its inception. In a "general rate case," a utility presents cost and demand data to justify a "revenue requirement" that meets its expected expenses, inclusive of returns that will attract investors to its stock and bonds.

At best, IRP has graphically shown that regulators have no better foresight than anyone else. The planning process that California initiated in the 1970s produced such an inefficient mix of resources and bureaucratized procedures that by 1993 even the staff of its Public Utilities Commission had called for an end to IRP and the introduction of competition.[21]

Federal Regulation

The Federal Power Act of 1935 established the Federal Power Commission (FPC), which in 1977 became the Federal Energy Regulatory Commission (FERC). Its original duties to license hydroelectric dams and allocate power produced at federal facilities are now a minor part of its workload. Most of the commission's electrical activities (it also regulates natural gas and oil pipelines) center around rates for "wholesale" transactions, defined (unlike everyday lan-

guage) as power sales intended for resale to retail customers, whose rates are under state jurisdiction. Wholesale transactions include trades of power and transmission service between utilities, as well as their purchases from non-utility power producers and marketers.

The law requires that FERC set rates at "just and reasonable" levels, which allow a wholesale seller to recover its expenses plus a return on capital. As wholesale transactions grew in the 1970s, FERC treated their prices as just and reasonable if the markets they took place in were competitive. A short-term energy trade between two utilities might, for example, "split the savings" between them, pricing it halfway between the seller's incremental costs (those of an extra kwh, mainly fuel) and the buyer's decremental costs (the expenses of self-supply that it saved). Wholesale contracts remain under FERC jurisdiction, but increasingly the Commission simply accepts filings without further investigation. It assumes that in competitive markets both parties have enough potential counterparties that their transaction creates economic value.

The law requires that FERC set rates at "just and reasonable" levels, which allow a wholesale seller to recover its expenses plus a return on capital.

Most wholesale power is ultimately resold by utilities to retail customers. The rest of a vertically integrated utility's power supply is produced by its own generators, whose output is dedicated to its "native load." Power producers of all types also supply energy into short-term bid-based markets, to be bought by entities with service obligations that find themselves short of energy. Where these markets exist they generally handle no more than 5 to 10 percent of total electricity. They generally determine prices no more than one day ahead of bidding, and some set them for delivery in an hour or less. FERC applies competitive "screens" to wholesale trades that determine whether there are enough sources of supply that sellers will be unable to exercise market power to raise prices and restrict output.[22] Much of the country passes the screens, but large sellers in areas that do not may only charge cost-based prices.

FERC's regulation of transmission rates and practices has been a major force behind the growth of competition. The commission allows a transmission owner to recover its costs plus a reasonable return on capital.[23] Although transmission lines are almost invariably government-granted monopolies, prior to the Energy Policy Act of 1992, FERC was unable to order their owners to carry power for others, including their potential competitors. The Commission now has powers to enforce nondiscriminatory access requirements. Authority over the siting of new transmission, including eminent domain, lies with the states, but the Energy Policy Act of 2005 gave FERC some authority to order construction if it determines a need for new facilities that states have not approved.

Municipal and Cooperative Utilities

Municipal electric utilities exist to distribute (and sometimes generate) power for local residents and businesses. They are also sources of revenue, usually sending city government a percentage of their gross receipts. These payments, in part, replace taxes and franchise fees that a corporate utility would have paid. In most states municipal rates are unregulated by public utility commissions. Municipal governments or local appointees usually set them, sometimes after a

study of service costs and sometimes by pegging them at or near those of the local corporate utility. Municipal systems are also largely exempt from FERC regulation.

The territorial conflicts between corporate and municipal utilities that occurred in the industry's early years are largely over today. Some municipals were first formed after corporate utilities chose not to incur the cost of serving their territories. Others originated in elections that terminated a corporate utility's franchise and bought up its lines and facilities. In the past 50 years there have been few franchise changeovers in either direction, but in principle the threat of an election may motivate an incumbent utility to keep rates down. A substantial number of municipal utility formations in earlier years were motivated by their legal priority over corporate systems to obtain inexpensive "preference" power from federal facilities, but nowadays very little of it is available. Larger generation-owning municipals like Los Angeles, San Antonio, and Seattle now participate in wholesale markets on much the same terms as profit-seeking entities.[24]

Like cooperatives in other industries, those that supply electricity are owned by customers, whose votes ultimately determine their policies. Most are only distributors of purchased power, but some are G&T (Generation and Transmission) operations. As nonprofit organizations, their rates and other policies are generally exempt from state and federal regulation. Like municipal systems, relatively little of the rivalry between cooperatives and corporate utilities from the last century remains, and their participation in wholesale markets is increasing.

Between the 1940s and 1970s, electric utility regulation looked like an easy job. By the early 1970s, the golden age was over.

From Regulation to Markets

How the Golden Age Ended

Between the 1940s and 1970s, electric utility regulation looked like an easy job. Regulators spent much of their time dividing the benefits of technological progress in generation between consumers and producers. Limits on transmission technology ensured that most corporate utilities were self-sufficient in generation. Constant increases in generator efficiency made it easy to satisfy both the interests of utilities and consumers. Over this period productivity growth in electricity was only equaled in a handful of other industries. As generators improved, utilities under cost-of-service regulation were happy to build more of them. The cost of power to retail customers fell as demand grew, while investors realized steady and attractive returns.

By the early 1970s, the golden age was over. Giant new coal-fired power plants were not as efficient as promised, and complexity made them less reliable. Nuclear facilities that had once promised power "too cheap to meter" would turn out to be phenomenally expensive, their costs far higher than anticipated and their on-line dates sometimes delayed by as much as a decade. The 1979 accident at Three Mile Island and subsequent regulations ensured that nuclear power would cease to be a relevant alternative for any utility.[25] Developments in fuel markets compounded the utilities' cost problems. By the early 1970s, wellhead

price controls on natural gas had created onerous shortages in interstate markets (the only ones subject to the controls until 1978) that would sometimes close gas-using businesses and threaten supply interruptions to homes that heated with it.[26] With no price controls in gas-producing states, market prices prevailed and some gas-fired generators remained economical. Coal remained abundant but air quality concerns made it the target of a growing environmental movement. New rules increased the costs of regulatory compliance for prospective builders of coal-burning plants. Environmental intervenors became active at regulatory commissions and in the courts, questioning the effectiveness and the ecological consequences of proposed plants and sometimes successfully delaying or shelving them. They also led some commissions to begin exploring conservation and demand limitation programs as alternatives to new generators.

The Coming of Inter-Utility Markets

The chaos of the 1970s also saw the beginnings of power trading.

The chaos of the 1970s also saw the beginnings of power trading. Plant cancellations and delays had left some with utilities in deficit while others owned more capacity than was needed by their own customers. Some compact regions like New England had long pooled generation owned by many different utilities and centrally operated it to meet the demand for power from the generating sources with the lowest costs on an hour-by-hour basis. Bilateral exchanges over longer distances became more common using newly developed extra-high-voltage lines that were managed by new control technologies. Some power trades that took advantage of short-term cost differences flowed for as little as an hour, while others allowed the parties to gain from seasonal load diversity. The 1970 completion of the Pacific Interties allowed California utilities to import inexpensive hydropower from as far away as Canada to meet their summer peaks, while California and the southwest profitably sent power back during the northwest's winter peak. Transactions like these reduced both immediate supply costs and requirements for investment in generators that would otherwise operate for only a few hours a year.

By the late 1970s, federal policy makers had singled out energy as the nation's most important problem. The Carter administration's policies were embodied in legislation intended to cope with what it believed was the impending exhaustion of energy supplies. Apparently deluded by declining oil and gas reserve statistics in the face of price controls, the administration intended to reduce consumption and utilize coal as a backstop fuel as other hydrocarbons ran out. It would also emphasize production of power by "renewable" technologies while minimizing potential production that was wasted. Two parts of the legislative package would transform electricity.

1. The Growth of Independent Power

The first of these laws, the Natural Gas Policy Act of 1978 (NGPA), had a twofold intent: to keep much existing gas under price controls put in place during the 1950s, while allowing newly discovered gas from deep wells to sell at market prices. Alongside the NGPA, the Powerplant and Industrial Fuel Use Act would phase gas out of many industrial applications including power generation in order to conserve it for uses that policy makers deemed

more valuable. As things happened, a complex set of causes produced a surplus of gas shortly after the NGPA's passage. By the mid-1980s the Fuel Use Act had been administratively nullified and federal policy intended to find new uses for gas, whose supply had been remarkably responsive to prices.[27] Adjusted for inflation the wellhead and delivered prices of gas would decline in every year between 1984 and 2003. In 1985, FERC in effect abolished the entire regime of ceiling prices under the NGPA. Gas was both economical and the fuel of choice for compliance with environmental regulation. The stage was set for a revolution in powerplant design.

The second law was the Public Utility Regulatory Policies Act (PURPA) of 1978. Prior to PURPA utilities acquired virtually all of their power from plants that they owned or through purchase agreements with other utilities. Cost-based regulation made them unwilling to trade with non-utilities like industrial plants that might generate their own power as a byproduct of heat creation. In addition, the government believed that "renewable" generators would only be developed if it forced utilities to purchase their output. PURPA set rules to determine facilities that qualified for utility purchases. It also required that state regulators set the "avoided cost" that utilities would pay, measuring the value of power they did not have to generate because of the purchase. Originally expected to apply to only a small amount of power, much from unorthodox sources, PURPA brought a rush to build new gas-burning plants. States like California and New York set very high avoided costs, at a time when gas was falling in price. Engineers began designing highly efficient gas-burning generators, some of which could be downsized that qualified for mandatory purchases under PURPA.

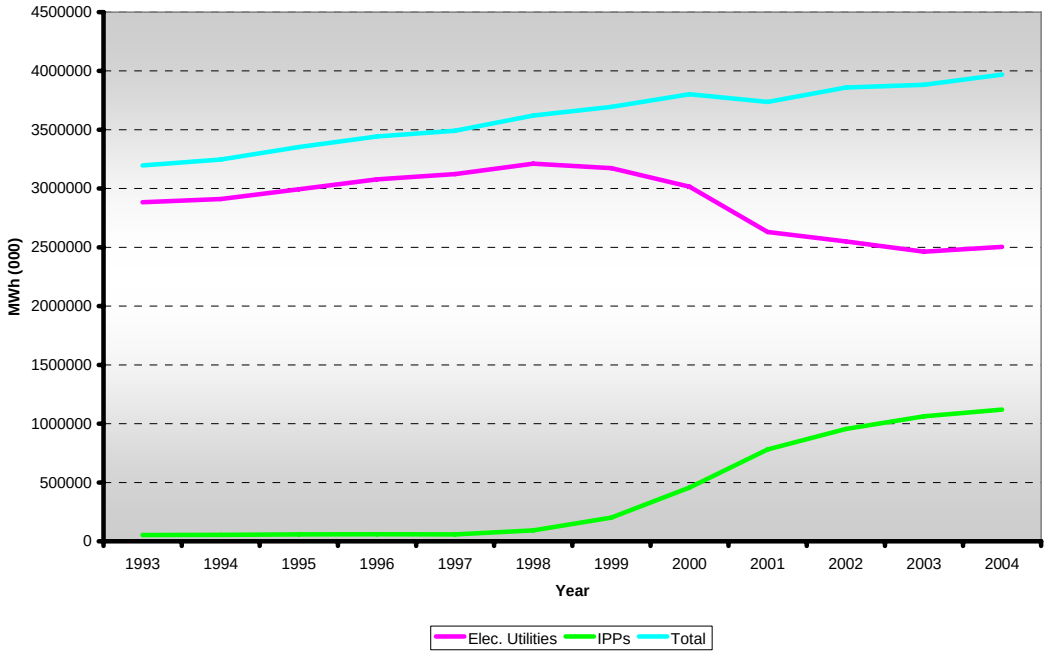
During the 1990s, independent power production (IPP) accounted for a significant and steadily increasing proportion of the total.

During the 1990s, independent power production (IPP) accounted for a significant and steadily increasing proportion of the total. **Figure 1-8** (page 20) shows the growth of their production and the decline of utility-owned generation relative to the national total. As the market grew, a new industry of wholesale marketers (Enron was one of the first) arose to construct transactions between IPPs and utilities. The Energy Policy Act of 1992 (EPAct) allowed FERC to order utilities to transmit non-utility power if necessary, whether the power was produced in PURPA facilities or larger independent plants, now known as Exempt Wholesale Generators (EWGs).[28] In 1996, FERC attempted to standardize transmission policy by issuing Order 888, which required utilities to file rates (known as tariffs) at the commission that were available to all qualified parties, thereby eliminating possibilities for discrimination or needless delays. The basics of today's wholesale markets were now in place.

2. Regional Transmission Operators

Even after Order 888, wholesale markets did not achieve their economic potential due to a number of factors, including the difficulty of arranging equitable power transactions over complex regional grids. The scheduling problems stem from the network technology discussed above. An agreement to flow power between two utility grids would specify a "contract path" along which the power would nominally flow and the charges for us-

Figure 1-8
Generation by Electric Utilities and Independent Power Producers, 1993-2004



Source: U. S. Energy Information Administration, from Annual Review of Energy, 2005, http://www.eia.doe.gov/emeu/aer/pdf/pages/sec8_9.pdf; http://www.eia.doe.gov/emeu/mer/pdf/pages/sec7_7.pdf.

ing it. Power, however, will flow along all the lines in the interconnection regardless of who owns them. These flows can confound the transactions of distant parties, and efficiently alleviating these problems may require centralized operation of all the region's systems. Even if a transaction causes no operating problems its fictitious contract path may cross several utility territories. Each of them will extract a charge for its portion of the path, a phenomenon called "pancaking." The pancaked total may be too high to warrant the making of a transaction, while the true costs to the region are low enough that the transaction should go through.

As markets grow, loop flows and pancaking can become greater obstacles to trade. FERC has attempted to deal with them by having all of a region's transmission owners surrender control to a Regional Transmission Operator (RTO, also known as an Independent System Operator or ISO). The RTO will operate its grid in a nondiscriminatory way, and price access to transmission at rates that allow the owners (who are still responsible for construction and maintenance) to recover their costs. There are currently six active RTOs, including ERCOT. FERC believes that RTOs are essential for competition but is unsure of its legal powers to order membership in them and is averse to a court test of those powers.

3. Retail Customer Choice

Over the 1980s and 1990s, many small municipal utilities and cooperatives succeeded in obtaining transmission service that allowed them to access power from distant sources. The small utilities could find power sources better suited for their particular needs, and possibly obtain bargains by entering transactions that others had overlooked. Transmission-owning corporate utilities retained responsibilities for obtaining or providing ancillary services like reserves, emergency aid, and residual power requirements at federally regulated rates. Some of these once "captive" utilities were smaller than individual industrial power users who generally had no opportunities to shop for power in this manner. Operating in highly competitive product markets, industrial users petitioned regulators for the right to choose suppliers. Because industrial rates often cross-subsidized residential users, state regulators were often unenthusiastic about allowing them to choose suppliers.

California's Experience

Other pressures would bring customer choice. In April of 1994, the California Public Utilities Commission was the first to take the jump.[29] Its own staff had previously acknowledged that the state's planning process had performed disastrously. California's corporate utilities (municipals are unregulated) were reluctant to lose their customers, particularly because they owned nuclear facilities whose value would be unrecoverable at competitive prices, and had signed power purchase contracts under PURPA whose prices were well above market levels. A complex and inconsistent set of political compromises brought forth enabling legislation, known as Assembly Bill 1890.

Operating in highly competitive product markets, industrial users petitioned regulators for the right to choose suppliers. Because industrial rates often cross-subsidized residential users, state regulators were often unenthusiastic about allowing them to choose suppliers.

Assembly Bill 1890 initiated a rate freeze at 1996 levels for all customers.[30] The state's three large corporate utilities would have to buy their entire power supplies in day-ahead and hourly markets operated by the newly formed California Power Exchange (PX) and Independent System Operator (ISO), and would divest most of their in-state gas-fired generation. The utilities had five years to recover their stranded costs,[i] and would bear the losses of any that remained unrecovered. Departing utility customers would continue to pay for their stranded costs in transmission charges. The utilities were spot-market dependent, unable to contract bilaterally for power or to use any financial or physical hedges against volatile market prices.

For two years after they began operation in April 1998, California's markets produced prices that tracked marginal costs quite closely (at these prices, owners of the acquired plants could recover their variable costs but not their capital costs). By summer of 2000, however, energy prices had risen well above the frozen rates customers were paying. A combination of bad weather, market

[i]Stranded costs are those costs a utility incurred under the system of vertically integrated regulated monopolies, that it would not be able to recover under a competitive market structure. In other words, the costs sunk into an regulator-approved power plant that could not be recovered if rates were lowered to meet competition from less expensive plants.

power by owners of divested generators, and the state's long-term supply-demand imbalance interacted to bring high energy prices. Pacific Gas & Electric filed for bankruptcy and Southern California Edison narrowly averted the same fate. The Legislature suspended customer choice and state government took over the purchasing functions of the insolvent utilities. It soon signed fixed-price contracts for the next 10 years of utility power supplies, but as luck would have it shortly after the contracts went into effect power prices fell drastically, leaving the state with a new set of stranded costs. California's singularly bad experience was more a reflection of its peculiar politics than of any inherent flaws in competitive electricity supply.

Retail Choice Today

As of today, 19 states (including Texas) and the District of Columbia allow retail customers access to competitive suppliers. For states with choice, **Table 1-1** shows the percentage of electric load that has switched to non-utility providers in the states with the most activity.[31] The performance of the individual states in customer switching varies greatly—approximately one-third of retail consumer loads in the nation have rights to switch, and approximately 63,000 MW of peak demand has been switched from utility provision.[32] The percentage of industrial load that has switched to non-utility suppliers ranges as high as 85 percent in Maine, while Texas leads the nation in the percentage of residential loads that have switched.[33] The table does not include information about important changes have occurred with the passage of time. In April of 2000, 35 percent of total Pennsylvania loads had switched to outside suppliers. The state's "shopping credit," however, was fixed in dollar terms.[34] Its failure to change with rising fuel prices made competition with utilities impossible for nearly all marketers, with the results shown in **Table 1-1**. Texas is almost alone in its continuing rise in loads of all types that have switched away from utility service.

California's singularly bad experience was more a reflection of its peculiar politics than of any inherent flaws in competitive electricity supply.

Table 1-1
Competitive Supply by State:
Percent of Load Served by Competitive Suppliers

State	Residential	Commercial	Industrial	All
CA	0.5	14.8	36.0	13.2
DC	8.3	67.1	67.1	55.2
IL	0.0	38.6	59.4	34.8
MA	2.2	26.5	48.8	22.3
MD	2.7	43.0	43.0	23.6
ME	0.9	34.9	85.2	38.0
MT	0.0	33.2	33.2	22.2
NY	6.9	36.5	66.9	32.2
OH	18.9	28.0	14.5	19.3
PA	3.3	16.2	10.5	9.3
RI	0.2	18.4	18.4	11.6
TX	26.0	81.6	81.6	55.4

Source: David O'Connor, "Can There Be Competition for Mass Market Consumers of Electricity," Presentation to Harvard Electricity Policy Group, May 19, 2005, http://www.ksg.harvard.edu/hepg/Papers/OConnor/. Data from KEMA, Inc., Retail Energy Foresight, April 2005.

Summary

Electricity's move to the market has been complicated by both technological, economic, and political factors. An electric system is very capital intensive and some of its most important facilities, particularly transmission, are natural monopolies that would be economically wasteful to duplicate. Electricity flows through a network in ways that render competitive operation of generators by their owners impossible. Instead, a system must be centrally controlled in order to match supply with demand at every instant, since failure to maintain this relationship will bring about regional blackouts. Nevertheless, developments in generation technology and operating practices have made market competition possible in some areas of the industry.

Any markets that are formed must take into account the realities of the industry's structure, which is particularly complex in America. Instead of the national utilities seen in many other developed nations, the U.S. is covered by a patchwork of distribution systems. Most are regulated corporations, but there is a substantial presence of municipally-owned systems and cooperatives. This fragmentation is further complicated by a dual regulatory system in which state commissions have control of rates to ultimate (retail) customers, while the federal government has jurisdiction over interstate transmission and wholesale transactions, defined as sales for ultimate resale. While the Federal Energy Regulatory Commission has actively attempted to foster competitive wholesale markets, many states are reluctant—for political reasons—to allow their residents and businesses to choose their own suppliers.

Nevertheless, competition—particularly at wholesale—has grown, in part because of FERC policy and in part because of legislation that unexpectedly produced a competitive industry of non-utility power producers and marketers, and that authorized FERC to take a more active role in ensuring nondiscriminatory access to transmission by wholesale producers, consumers and marketers. At the state level some programs that allow retail choice, like California's, are moribund and the promise of others like Pennsylvania's is vanishing as flaws in its underlying legislation become apparent. Texas, however, has had a near-uniform record of success at instituting competition in both its wholesale and retail markets.

Texas has had a near-uniform record of success at instituting competition in both its wholesale and retail markets.

Endnotes

[1]U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, *Overview of the Electric Grid.* http://www.energetics.com/gridworks/grid.html.
[2]*Overview of the Electric Grid, Op. Cit.*
[3]Edison Electric Institute, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures 1999 - 2008*, 3-4. http://www.eei.org/industry_issues/energy_infrastructure/transmission/Trans_Survey_Web.pdf
EEI is the trade association of the nation's corporate utility companies.
[4]U.S. Department of Energy, *Electric Power Annual 2004* (Nov. 2005) Tables ES and 6.1. http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.
[5]Electric Power Supply Association, *Competitive Power Supply Industry Facts* http://www.epsa.org/Competition/quick_facts_mp.cfm and http://www.epsa.org/Competition/EPSA_Choice_Map.pdf.
[6]A small amount of transmission carries direct current (DC), which is only of peripheral relevance.
[7]A megawatt-hour is roughly sufficient to serve 1000 average American residences. Air conditioning puts consumption per Texas household above the national average.
[8]*Electric Power Annual 2005, Op. Cit.* Data Tables at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.
[9]U.S. Department of Energy, *Tracking New Coal-Fired Power Plants* (21 June 2006) http://www.netl.doe.gov/coal/refshelf/ncp.pdf.
[10]Northwest Power Planning Council, "Natural Gas Combined Cycle Gas Turbine Power Plants," (8 Aug. 2002) http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf.
[11]All data are from U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 2004*, Table 1.1. http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile1_1.xls.
[12]There are fewer circuit miles than so-called pole-miles, because a single transmission tower often carries two or more separate lines.
[13]National Regulatory Research Institute, *Some Economic Principles for Pricing Wheeled Power,* Ohio State University, 1987: 52.
[14]National Regulatory Research Institute, *Op. Cit.*, 41-57.
[15]U.S. Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, Ch. 3, http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/chapter3.html.
[16]*Electric Power Annual 2005, Op. Cit.*, Table 7.2, http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile7_2.xls . The remainder of deliveries are for miscellaneous uses like street lighting and agricultural pumping.
[17]American Public Power Association, *U.S. Electric Utility Industry Statistics* (2004) http://www.appanet.org/files/PDFs/2006StatCharts.pdf.
[18]The territories are held by Center Point Energy (formerly Reliant), TXU Electric Delivery (Formerly Texas Utilities), Texas-New Mexico power company, Xcel energy, Entergy Texas, and American Electric Power, whose two operating companies in the state are AEP Central and AEP North.
[19]U.S. Department of Energy, Energy Information Administration, *State Electricity Profiles 2001,* DOE/EIA 0629 (Oct. 2003) 190. http://tonto.eia.doe.gov/ftproot/electricity/stateprofiles/01st_profiles/062901.pdf.
[20]*See* Figure 3-2 below.
[21]California Public Utilities Commission, Division of Strategic Planning, "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future," (3 Feb. 1993) http://www.cpuc.ca.gov/Published/Report/3822.htm.
[22]FERC is currently in the process of revising these rules. *See* "Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities," Docket No. 04-7-000 (19 May 2006) http://www.ferc.gov/whats-new/comm-meet/051806/E-2.pdf.
[23]The jurisdictional split between state and federal regulation has become a matter of increasing contention as the scopes of wholesale markets have grown to subsume wide regions. In practice rules of cost allocation that have little economic significance determine the proportions of transmission and generation that FERC controls.
[24]In California's 2000-2001 crisis, municipals like the Los Angeles Department of Water and Power sometimes sold electricity to power-short corporate utilities at the same extremely high market prices that non-utility power producers were receiving. On the other hand the last major transmission line crossing the California border was built by a consortium of municipal systems, and is sometimes used by corporate utilities. The municipalities were able to build it because they were not subject to the same state permitting procedures that allowed regulators to reject applications from corporate utilities.
[25]In Texas generation owners are considering the expansion of some existing nuclear plants, as will be discussed in a later paper.
[26]As noted above, very few powerplants burned oil so the embargo of 1973-4 had little direct impact on the power industry. Existing price controls on domestic oil and gasoline imposed in 1970 aggravated the gas shortage by discouraging oil exploration. A substantial fraction of gas reaching the market was associated with oil discoveries.

[27]Robert J. Michaels, "The New Age of Natural Gas: How the Regulators Brought Competition," *Regulation* (Winter 1993) 16. http://www.cato.org/pubs/regulation/reg16n1e.html.
[28]"Exempt" meant that they were not required to meet the financial strictures of the Public Utility Holding Company Act of 1935, which had been enacted to control the financial structuring of utilities after the downfall of Samuel Insull's paper empire.
[29]California Public Utilities Commission, Order Instituting Rulemaking and Order Instituting Investigation, Docket Nos. R.94-04-031 and I.94-04-032 (20 Apr. 1994). This document has been removed from the web sites of the CPUC and California Energy Commission.
[30]Small consumers actually got a 10 percent discount, to be financed by bonds that they would ultimately have to pay off.
[31]David O'Connor, Can There Be Competition for Mass Market Consumers of Electricity," Presentation to Harvard Electricity Policy Group (19 May 2005) http://www.ksg.harvard.edu/hepg/Papers/OConnor/. Data from KEMA, Inc., Retail Energy Foresight (Apr. 2005).
[32]Data on total states are from the Electric Power Supply Association, the trade group of non-utility power producers. http://www.epsa.org/competition/quick_facts_mp.cfm. California's program was suspended in 2001, but users who had left the system were allowed to continue their contracts with outside suppliers. Other states have retail choice, but most of them have seen relatively little switching. They include Arizona, Connecticut, Delaware, Michigan, Nevada, New Hampshire, New Jersey, Oregon, and Virginia.
[33]As of July 2006, 89 percent of Central Maine Power's and 90 percent of Maine Public Service's large industrial customers had switched suppliers. "Maine Power Shopping up at Two Utilities," *Restructuring Today* (29 Aug. 2006) 3.
[34] "PUC's Fitzpatrick Sees Big Fixes in Penna. Market," *Restructuring Today* (2 Nov. 2001) 1.

About this Report

As of today, 19 states and the District of Columbia allow retail customers access to competitive suppliers. Texas has moved the fastest and furthest toward successfully providing consumer choice in the electric market, and is almost alone in its continuing rise in loads of all types that have switched away from utility service. While Texas leads the nation, many other states have faltered and given up on these efforts.

Electricity has always been an important public policy issue. Because of the complexity of the electric markets and related public policy, this paper—the first in a series—is a primer on electricity providing a foundation for our examination in future papers of the successes and challenges in the move toward deregulation in Texas electric markets.

About the Author

Robert J. Michaels is a Professor of Economics at California State University, Fullerton. His areas of qualification are industrial organization; antitrust analysis; regulation and deregulation; and competition in the electricity and gas industries.

Dr. Michaels has conducted significant research on electric markets, including areas such as market power in California, regulating competitive electricity, and FERC'S California market order. He has also testified before the U.S. House of Representatives Subcommittee on Energy and Power, the Federal Energy Regulatory Commission, the California Public Utilities Commission, the Illinois Commerce Commission, the California Energy Commission, and the Superior Court of California.

Dr. Michaels is a Senior Fellow at the Texas Public Policy Foundation; a Resident Scholar at the Center for Advancement of Energy Markets; Co-Editor of *Contemporary Economic Policy*, a peer-reviewed journal of the Western Economic Association; and an Adjunct Scholar at the Institute for Energy Research.

He holds an A.B. from the University of Chicago and a Ph.D. from the University of California, Los Angeles, both in economics.