Chapter 2

An Overview of the Changing Electric Power Industry

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An Overview of the Changing Electric Power Industry

INTRODUCTION

This chapter provides an overview of the structure and regulation of the electric power industry. The first section provides information on utility ownership, generation and transmission resources, electricity demand growth, and recent financial trends among private utilities.[1] *The second section concludes with a brief introduction to Federal and State regulation of electric utilities, bulk power markets, and transmission access.*

A SNAPSHOT OF THE ELECTRIC POWER INDUSTRY TODAY

Industry Ownership and Structure

The *electric power industry today is a diverse and heterogeneous amalgamation of investor and publicly owned utilities, government agencies, cogenerators, and independent power producers. The industry consists of more than 3,200 entities that supply electricity to more than 100 million households, commercial establishments, and industrial operations. At present, there are 203 investor-owned utility operating companies, 1,988 local publicly owned systems (including municipal, State, county and regional systems),* **994** *rural electric cooperatives (including 885 distribution co-ops and 59 generation and transmission co-ops), 59 public joint-action agencies, 6 Federal power agencies, and several hundred cogeneration and small power* producers.[2] Table 2-1 shows installed generating capacity and generation by ownership.

Investor-Owned Utilities

The 203 *investor-owned utility operating companies dominate the electric power industry, generating 76 percent of the Nation's power and serving about 75 percent of all retail customers.*[3] *These companies are an assimilation of some 2,000 private utility systems that were in existence in the 1920s. Actual control of the industry is somewhat more centralized because nearly one-quarter of the remaining utility operating companies are subsidiaries of nine registered electric utility holding companies regulated under the Public Utility Holding Company Act of 1935 (PUHCA). The registered utility holding companies are: Allegheny Power System, Inc., American Electric Power Co., Central and South West Corp., Eastern Utilities Associates, General Public Utilities Corp., Middle South Utilities, New England Electric System, Northeast Utilities, and The Southern Company. In addition to the regulated holding companies, there are "exempt" holding company systems consisting of affiliated utility subsidiaries operating intrastate or in contiguous States.*

Federal Systems

The *Federal Government is primarily a wholesaler of electric power produced at federally owned hydroelectric facilities operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers. Power is marketed through five Federal marketing agencies—Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, Southwestern Power Administration, Alaska Power Administration-and through the independent Tennessee Valley Authority, a government corporation. Together, Federal systems had an installed generating capacity of approximately 64,000 megawatts (MW) and accounted for 8.4 percent of the Nation's power generation in 1987.*[4] *All Federal power systems are required under existing legislation to give preference in the sale of their output to other publicly owned systems and to rural electric cooperatives.*

Local Public Systems

In addition to the Federal systems, there are 1,988 local, municipal, State, and regional public power systems ranging in size from tiny municipal distribution companies to giant systems like the Power

[1] Much of the information i, this section is drawn from an OTA contractor report, Scott A. Fenn, "An Overview of the Changing Electric Power Industry," December 1988.

[2] "U.S. Electric Utility Statistics, " *Public Power,* January-February 1989. p. 51.

[3] Ibid.

[4] Ibid.

Table 2-l-Electric Utility Industry Installed Generating Capacity and Generation by Ownership, 1987

Type of ownership	Nameplate capacity (MW)	Generation (millions of kwh)
Investor-owned	552,795	2,022,260
Federal	64,666	205,363
Municipal	39,378	86,211
States and power districts	34,858	135,786
Cooperatives	26,359	122,508
Total	718,056	2,572,128

SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1987* (Washington, DC: December 1988).

Authority of the State of New York. Publicly owned systems are in operation in every State except Hawaii. Municipal systems are usually run by the local city council or an independent board elected by voters or appointed by city officials. Other public systems are typically run by public utility districts, irrigation districts or special State authorities. Together, local public power systems generated 10.2 percent of the Nation's power in 1987 but accounted for 14.3 percent of total electricity sales, reflecting the fact that many public systems are involved only in retail power distribution.[5]

Rural Electric Cooperatives

Electric cooperatives, an outgrowth of Federal Government efforts to bring electricity to rural areas, now operate in 46 States. Rural co-ops are owned by their members, each of whom has one vote in the election of a board of directors. Congress created the Rural Electrification Administration (REA) in 1935 and subsequently gave it broad lending authority to stimulate rural electricity use. Cooperatives have access to low-cost government-sponsored financing through the REA, the Federal Financing Bank, and the Bank for Cooperatives. Early REA borrowers tended to be small cooperatives that purchased wholesale power for distribution to members. Over the past 20 years, however, many expanded into generating and transmission cooperatives in order to lessen their dependence on outside power sources. In 1987, rural co-ops accounted for 5.2 percent of total power generation and 6.9 percent of sales to ultimate customers.[6]

Industry Power Operations and Coordination

In *most areas of the country, utility systems are now highly interconnected and operate under a variety of formal or informal coordination agreements. The level of power transfers and coordination between utilities is determined largely by physical interconnections, power pooling arrangements, and control centers.*

Interconnections

North *America's interconnected utilities create four physically separate, synchronously operated transmission networks: the Eastern Interconnection (or Seven Council Interconnection); the Texas Interconnection; the Western Systems Coordinating Council (WSCC); and the Hydro Quebec System. The boundaries for these transmission networks are shown in figure 2-1. DC and AC transmission interties between the networks are limited in location and capacity, with the result that the transmission systems in the United States do not form a single national grid, but rather form three separate grids. The transmission barriers between the three grids effectively limit the market areas for electric power in the United States For instance, there is little opportunity for long-distance power transfers between relatively low-cost* **surplus** *power areas in the Western Systems network and the higher-cost power systems in the Midwest or between the Texas Interconnection, with its abundance of cogeneration capacity, and utilities in the Southeast. There are sound technical reasons for maintaining the integrity*

[5] 1bid.
[6] Ibid.

Figure 2-l--Interconnections of the North American Electric Reliability Council

SOURCE: North American Electric Reliability Council, 1987 *Reliability Assessment: The Future of Bulk Electric System Reliability in North America, 1987-1996,* September 1997.

of separate synchronous transmission networks. However, it would be possible to construct AC-DC-AC interties to allow greater power flows between these regional networks without disrupting synchronous operations.

Power Pools

There are two types of power pool arrangements—tight power pools, which include holding company power pools, and loose power pools. The nine tight power pools are highly interconnected, centrally dispatched, and have established arrangements for joint planning on a single-system basis. Four of these tight pools consist of utility holding companies with operations in more than one State; the others are mostly multiutility pools. Together, the tight power pools account for about a quarter of the industry's total generating capacity. Figure 2-2 shows the location of the major tight power pools in the United States.

In addition to the tight power pools, there are a number of loose power pools. Arrangements among utilities in loose power pools are quite varied and range from generalized agreements that coordinate generation and transmission planning to accommodate overall needs to more structured arrangements for interchanges, shared reserve capacity, and transmission services.

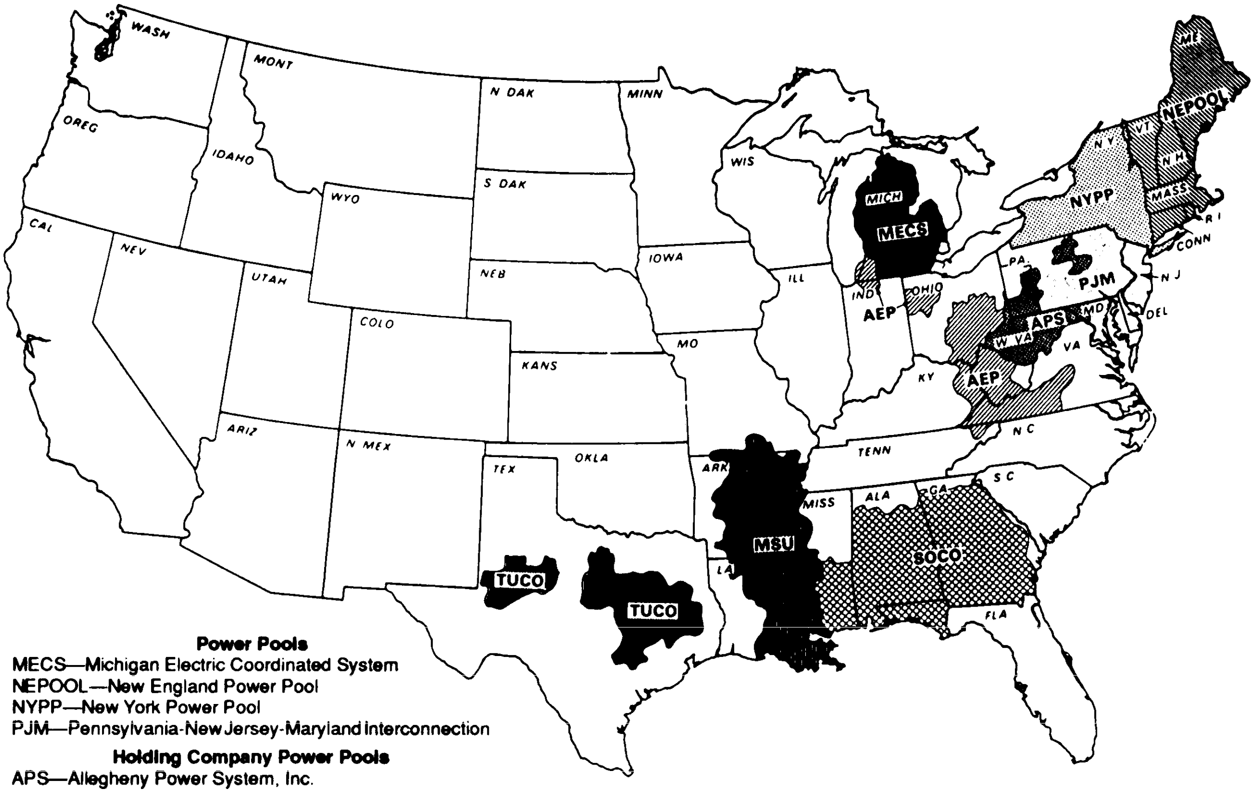
Existing interutility obligations and economic dispatch and transmission arrangements in interconnected and highly coordinated power pools may tend to limit opportunities for expanded competition in some areas for several reasons. Among the most significant are constraints imposed by existing long-term pooling contracts and the extent of operating economies already captured by pooling. In areas without extensive pooling agreements, increases in power pooling, coordination, and/or power brokering could offer benefits from better utilization of existing capacity that might be similar to those claimed for greater competition in bulk power purchases. One recent study indicates that the savings to consumers resulting from utility coordination and pooling arrangements total in excess of $15 billion annually, and that these annual savings can be expected to increase to more than $20 billion by the mid- 1990s.[7]

Control Areas

Responsibility for the operation of the Nation's generating facilities and transmission networks is divided among more than 140 "control areas. " In an operational sense, control areas are the smallest units of the interconnected power system. A control area can consist of a single utility, or two or more utilities tied together by contractual arrangements. The key characteristic is that all generating utilities within the control area operate and control their combined resources to meet their loads as if they were one system. If a single control area is used to dispatch the generating facilities of several utilities to minimize overall costs, the process is known as "central dispatch." Because most systems are interconnected with neighboring utilities, each control area must assure that its load matches its own internal generation plus power exports (or interchanges to other control areas) less power imports. Because of interconnection, each control area must satisfy more stringent requirements for generation control, frequency control, and tie line flows than would be needed for an isolated system. Control areas coordi-

TJohn A. Casazza, ''Free Market Electricity: Potential Impacts on Utility Pooling and Coordination, " *Public Utilities Fortnightl),* Feb. 18,1988, pp. 16-23.

Figure 2-2—Tight Power Pools in the United States



Power Pools

MECS—Michigan Electric Coordinated System
NEPOOL—New England Power Pool
NYPP—New York Power Pool
PJM—Pennsylvania-New Jersey-Maryland Interconnection

Holding Company Power Pools

APS—Allegheny Power System, Inc.
AEP—American Electric Power Company, Inc.
MSU--Middle South Utilities, Inc.
SOCO-The Southern Company
TUCO-Texas Utilities Company

SOURCE: Federal Energy Regulatory Commission, Office of Electric Power Regulation, *Power Pooling in the United States* (Washington, DC: December 1981).

nate transmission transactions among electric power systems through neighboring control areas. Control areas maintain frequent communications about operating conditions, incremental costs, and transmission line loadings.

There are about 99 control areas in the Eastern Interconnection, about 34 in the Western Interconnected System and 10 in the Texas Interconnected System. Figure 2-3 shows the North American interconnected control areas in 1981.

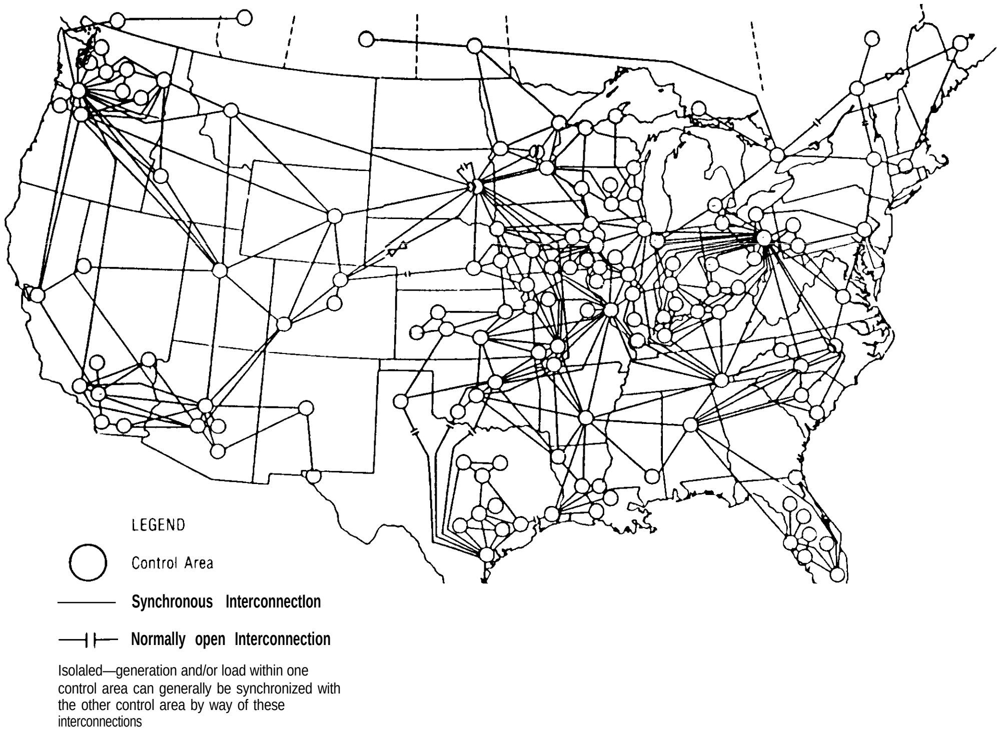
Electricity Generation, Demand and Supply

Major shifts in electric power usage patterns have bedeviled utility planners and energy forecasters since the oil embargoes of the 1970s made previous assumptions about fuel prices, inflation, and economic growth obsolete. Throughout the past decade, the electric utility industry has faced a situation of excess capacity as power plants, ordered in the 1970s, came on line and demand growth fell below the industry's expectations. As it enters the 1990s, however, the industry's problems with excess capacity appear to be receding and, in some regions of the country, capacity margins are tightening to the point that utilities are warning of shortages.

Demand and Peak Growth

Before 1970, electricity demand growth was vigorous and predictable, with power usage growing at an average annual rate of 7.8 percent and peak demand growth averaging 8.1 percent a year be-

Figure 2-3--North American Interconnected Control Areas, 1981



SOURCE: Federal Energy Regulatory Commission, Office of Electric Power Regulation, *Power Pooling in the United States* (Washington, DC: December 1981)

tween 1945 and 1970.[8] Utilities underestimated the price elasticity of electricity demand, however. and as consumers reacted to electricity price increases in the 1970s, growth in power demand fell sharply. Since 1973, peak demand growth-the chief determinant of the need for new capacity—and annual kilowatthour (kWh) sales growth have both averaged about 2.5 percent annually.[9] As shown in table 2-2, utility industry expectations of future electricity demand growth—for both peak demand usage and net energy usage—have been reduced in every year during this period and are now below the post-embargo average.

The drop in electricity demand growth is largely a reflection of a stagnation in the average growth of overall energy demand since the early 1970s. Total U.S. energy consumption in 1987 was only slightly higher than it was back in 1973 before the first oil shock, even though the real gross national product rose 39 percent, or about 2.4 percent annually, during this period. Thus, the only source of growth in electricity demand for 15 years has been an increase in electricity's market share relative to other end-use fuels. Electricity has steadily increased its share of the total U.S. energy market from 24.4 percent in 1970 to a record 36.2 percent in 1987 (see figure 2-4).

There are signs that electricity demand growth is beginning to accelerate again in the late 1980s in response to vigorous growth in the economy, including the revival of a number of energy-intensive manufacturing industries and a strong commercial

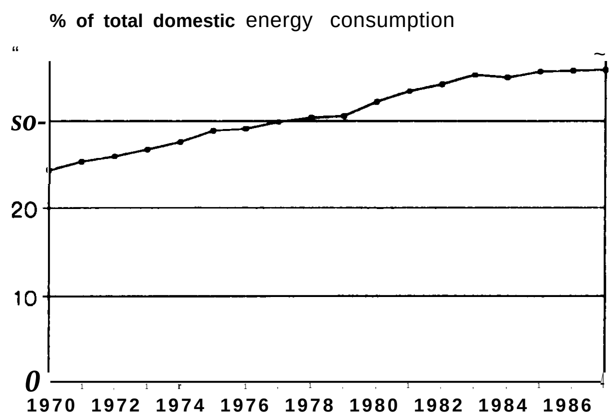
8 Arthur A. Thompson, "The Strategic Dilemma of Electric Utilities-Part I," *Public Utilities Fortnightly*, Mar. 18, 1982, p. 20.
9 Based on figures from Edison Electric Institute, *Statistical Yearbook of the Electric Utility industry/1986.* Data exclude Alaska and Hawaii.

Table 2-2--Industry Projections of U.S. Electric Load Growth

Forecast published	Forecast period	Average annual peak demand growth	*Average annual net energy growth
1974	1974-83	7.6	7.5
1976	1976-85	6.4	6.3
1978	1978-87	5.2	5.3
1980	1980-89	4.0	4.1
1982	1982-91	3.0	3.3
1964	1984-93	2.5	2.6
1986	1986-95	2.2	2.3
1988	1988-97	1.9	2.0

SOURCE: North American Electric Reliability Council, *Electricity Supply and Demand*, published each year.

Figure 2-4--Electric Power's Energy MarketShare, 1970-87



SOURCE: U.S. Department of Energy.

and service sector. Nationwide, summer peak demand growth for the industry reached 3.4 percent in 1986, 4.2 percent in 1987, and 6.1 percent in 1988, while total electricity kWh sales rose 2.1 percent in 1986, 3.7 percent in 1987, and an estimated 4.6 percent in 1988.[10]

Growth in electricity demand in recent years is rekindling debate over whether utilities are building sufficient capacity to meet future demand and how they should meet this demand. A number of analysts contend that the industry is now underestimating future demand growth in the same way that it overestimated such growth over the past decade. Other analysts, however, contend that customer responses to higher electricity prices-including efficiency investments, relocation of production facilities outside the United States, and onsite power production— will continue to moderate future demand for utility-produced power.

Generating Capacity

Total installed electric utility generating capacity reached 718,056 MW in 1987, an increase of 1.5 percent over 1986, with investor-owned utilities accounting for 77 percent of this capacity.[11] The distribution of this installed nameplate capacity by type of ownership is shown in table 2-1. In addition to this utility-owned capacity, it is estimated that nonutility companies had installed approximately 25,000 MW of cogeneration and small power capacity through 1987.[12]

Fuel Mix

Coal is the dominant source of U.S. electric generation, providing 56.9 percent of all electricity generated in 1987, as shown in figure 2-5. Nuclear power provided 17.7 percent, hydroelectric facilities provided 9.7 percent, natural gas accounted for 10.6 percent, fuel oil provided 4.6 percent, and other sources—including geothermal, wood, waste, wind and solar-accounted for the remaining 0.5 percent.[13]

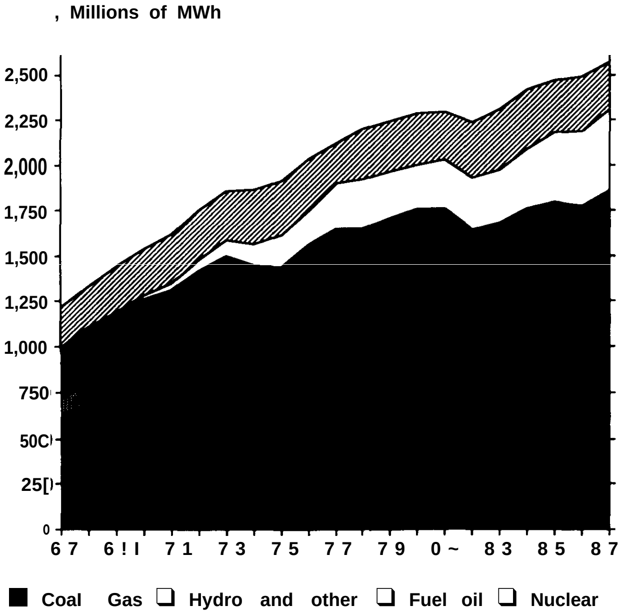
10 Carl Tobie, personal communication, Edison Electric Institute, Feb. 13, 1989.

11 Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1987* (Washington, DC: December 1988), p. 6.

12 "EEI: Over 25,000 MW of Non-utility Capacity Was in Service As of 1986," *Electric Utility Week*, Aug. 5, 1988, p. 13; and "Profile of Cogeneration and Small Power Generation Markets-1988 Edition," *Energy User News*, May 23, 1988, p. 2.

13 Edison Electric Institute, supra note 11, p. 32.

Figure 2-5--Electric Power Generation by Fuel Source



SOURCE: Edison Electric Institute, Statistical *Yearbook of the Electric Utility Industry/ 1987* (Washington, DC: December 1988).

Capacity and Reserve Margins

To meet expected load growth and to preserve system reliability, utilities maintain generating capacity reserves. Reserve margins express the difference between demonstrated capacity and peak demand as a percent of total peak. The traditional industry target has been to maintain a 20 percent reserve margin, although individual utilities have adopted different targets depending on many factors, including individual plant characteristics (e.g., age, size, type), access to power from other systems, and characteristics of customer demand. Actual electric utility industry reserve margins increased from around 20 percent in the early 1970s to 30 percent in the late 1970s and reached 35 percent in the mid-1 980s before beginning to decline-although there are significant differences in reserve margins on a regional basis as discussed in chapter 6. Trends in annual industry capability, summer peak loads, and adjusted capacity margins are shown in table 2-3.

Transmission Capacity

Transmission systems have been utilized in the past for the delivery of both capacity and energy. Under the first function, the seller provides a fixed amount of capacity and associated energy to the buyer for a specified time. Because the provision of this capacity is contractually guaranteed, the purchasing utility can include it in its reserve margin and use it as a substitute for additional generating capacity. In contrast, when energy alone is sold, the seller provides a given amount of energy over a specified period of time, but the availability of energy at any instant is not assured. This type of arrangement enables the purchasing utility to reduce its costs by substituting less expensive purchased power for more expensive electricity from its own generating stations, but it does not reduce the amount of generating capacity needed by the purchaser to meet reserve requirements.

In recent years, because of high industry reserve margins, transmission systems have been used more for providing energy to reduce *fuel costs than for providing capacity to avoid construction of new generating facilities.* As *industry reserve margins fall, however, the capacity function of transmission systems is expected to become more significant.*[14] *The pace of new transmission line additions has been declining in recent years. As of year-end 1987, the U.S. transmission system consisted of about 616,400 circuit miles of transmission lines of 22 kilovolts (kV) and above.*[15] *Approximately 79 percent of these circuit miles were owned by investor-owned utilities,*

Bulk Power Sales and Wheeling

Bulk power sales are defined as the sales of electricity at wholesale for resale or transmission of power for other systems (wheeling service). Such transactions constitute a significant share of total electricity sales in the United States.[16] *Wholesale power sales are generally divided into two categories: requirements sales, in which typically a vertically integrated, investor-owned utility sells power to meet the demand of a publicly owned utility that*

[14] See John A. Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination." *Public Utilities Fortnightly*, Feb. 18,1988, p. 16.

[15] Edison Electric Institute, supra note 11, p. 97.

[16] Linda Martinson and Thomas Loria, "The Transitional Bulk Power Market," *Public Utilities Fortnightly*, Nov. 26, 1987, p. 19.

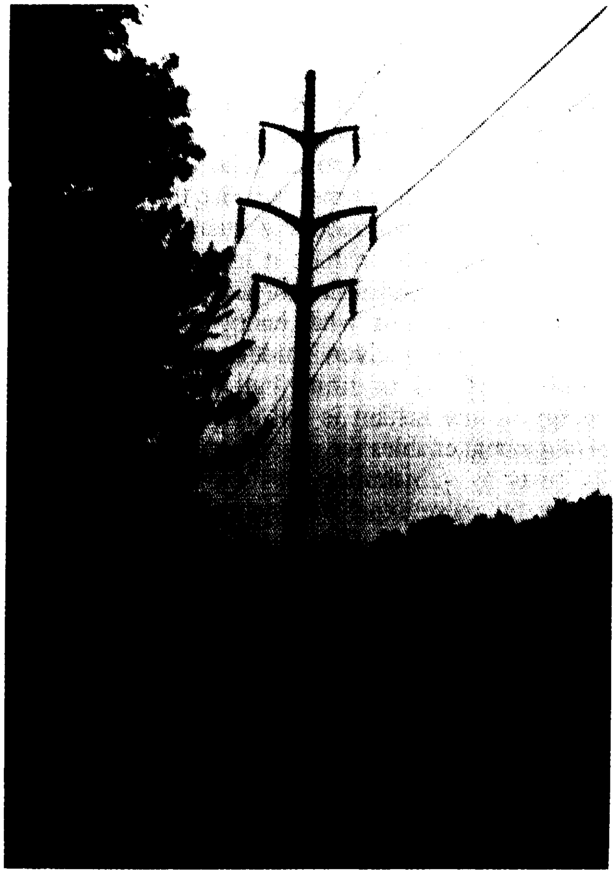


Photo credit: Casazza, Schultz & As.sock3tes, Inc.

A modem high voltage tower

owns little or no generating capacity; and coordination sales, typically involving two vertically integrated, investor-owned utilities.

Meanwhile, wheeling transactions, involving the transmission of power between two utility systems on a prearranged basis over the lines of one or more other systems, have become routine in the industry. Wheeling transactions are arranged on a voluntary basis and are generally subject to approval by the Federal Energy Regulatory Commission (FERC), where there are currently about 1,400 such agreements on file. Cost disparities and the development of sophisticated communications and control technologies have fostered an increasingly active market in bulk power transfers between utilities. Canadian power imports are also increasing. (See box 2-A on recent trends in bulk power purchases from Canada.) There are pressures from some sectors of the power industry to expand the number and the size of these transactions and to make them a more integral part of electric system planning. Independent power producers and cogenerators, in particular, see greater access to transmission facilities as essential to their future growth.

Electricity Prices

Prices *for electricity, like virtually all energy supplies, rose substantially in the 1970s and early 1980s in response to higher oil prices and general inflationary pressures in the economy, Unlike fossil fuel prices, however, which have retraced much of their earlier upward climb in recent years due to an excess of world oil production over demand, electricity prices have moderated only slightly. In large measure, this is due to the impact of a generation of very expensive generating plants, particularly nuclear units, that entered service during the 1980s. In addition, the fact that electricity prices are regulated*

Table 2-3-Total Electric Utility Industry Capability, Peak Loads, and Capacity Margins (excluding Alaska and Hawaii)

Year	Capability at time of summer peak load	Noncoincident summer peak load	Capacity margin at noncoincident peak
1978	545.7	408.1	25.2
1979	544.5	398.4	26.8
1980	558.2	427.1	23.5
1981	572.2	429,3	25.0
1982	586.1	415.6	29.1
1983	596.4	447.5	25.0
1984	604.2	451.2	25.3
1985	621.6	460.5	25.9
1986	633.3	476.3	24.7
1987 [a]	647.9	496.2	23.4

[a]Preliminary

SOURCE: Edison Electric Institute, *Annual Report of the Investor-Owned Electric Utility Industry*, 19/37 *Financi'al Review*.

Box 2-A—Electric Power Imports From Canada

As economic, political, and environmental problems have led to a slowing of new power plant construction in the United States, a number of U.S. utilities have begun to turn to Canadian imports as an attractive option for meeting future demand. Since the early 1970s, U.S. utilities have steadily increased the amount of power purchased from Canada-from less than 10 billion kWh in 1970 to an estimated 42 billion kWh in 1987—with roughly three-quarters of these imports displacing imported oil. The U.S. Department of Energy estimates that since the 1973 oil embargo, Canadian power imports have resulted in savings of more than $7 billion for U.S. consumers compared to the cost of imported oil.

While still accounting for less than 2 percent of total U.S. electricity demand, Canadian imports are significant in certain regions. In the State of New York, for instance, Canadian imports have accounted for about 12 to 17 percent of total power supplies in recent years. In addition, electricity imports from Canada are poised for further growth.

There is widespread agreement among utility industry experts that Canadian power imports will continue to grow, although there are substantial differences of opinion about the extent of this growth. Most estimates predict that import levels could range from 52 to 66 billion kwh annually by 1995. Among the factors that are leading to growth in imports are:[1]

- **Canadian energy reserves:** Canada has enormous untapped energy reserves, including economically attractive undeveloped hydroelectric reserves in northern Canada capable of supplying as much as 60,000 MW of generating capacity for which there is currently no Canadian market.
- **Ease of power plant construction:** In general, power plant construction appears to be somewhat less onerous in Canada than in the United States. Construction delays, cost overruns, and prudence reviews by regulators have made U.S. utilities extremely cautious about new plant construction.
- **Canada's economy and industry structure:** General economic conditions in some Canadian provinces, along with the government-owned structure of the Canadian provincial utilities, are making the construction of power plants for the export market increasingly attractive. Three provincial utilities are considering accelerating the construction of hydroelectric facilities for the U.S. export market. British Columbia has also formed a provincially owned corporation to sell privately produced power exclusively to export markets in the Western United States.
- **The U.S.-Canada Free Trade Agreement:** The recently negotiated U.S.-Canada Free Trade Agreement is expected to enhance the prospects for future electricity trade by increasing the security of Canadian energy supplies and lowering the cost of imports through the elimination of a discriminatory price test.

As Canadian imports grow, the arrangements under which power is being sold to U.S. utilities are also changing. To date, most Canadian imports-72 percent in 1986-have been interruptible economy transactions. Power sales are now shifting from short-term interruptible sales to firm, longer term contracts for energy and capacity. In 1987 alone, U.S. and Canadian utilities signed three major multi-billion dollar, multiyear power import deals. As a result, U.S. utilities are increasingly able to use Canadian electricity imports to defer or cancel new domestic power plant construction.

The most important limitation on future growth of Canadian imports is likely to be a shortage of transmission capacity. At present, more than 30 high-voltage transmission lines cross the border between the United States and Canada, with a carrying capacity of more than 10,000 MW. Each region along the northern tier of the United States has at least several lines. Most of these lines already operate near full capacity, however; so plans to expand U.S.-Canadian electricity trade further will require construction of additional transmission capacity. The New England Power Pool, for instance, is building a $570 million, 130-mile transmission line from the endpoint of its existing interconnection with Hydro-Quebec in New Hampshire to Massachusetts in order to begin importing an additional 7 billion kWh annually from Canada. Acquiring right-of-way for new transmission lines is difficult though, and a recent wave of public concern about the possible health effects associated with transmission lines is likely to intensify opposition to new lines.

[1] See Dina Washburn Kruger, *Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade* (Washington, DC: Investor Responsibility Research Center, 198S).

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Moreover, technical, economic, and environmental concerns in the United States and Canada may limit further expansion of electricity trade. Some U.S. utilities are concerned about the reliability of Canadian supplies, particularly in light of weather-related curtailments by Hydro-Quebec in January and April 1988. Others are opposed to imports because of the pricing structure used by Canadian utilities, which ties import prices to the importing utility's cost of displaced generation. Finally, many Canadians remain opposed to exploiting Canada's untapped energy resources for the U.S. market and a growing environmental movement within Canada could constrain the development of new hydroelectric dams.

These concerns notwithstanding, it appears that over the near term, the powerful forces driving import growth will overshadow import opponents. Over the longer term, it is also possible that emerging environmental concerns, such as global warming caused by the burning of fossil fuels, will give new impetus to the development of noncombustion technologies such as Canada's hydro resources.

The likely beneficiaries of growing cross-border electricity trade include U.S. consumers, utilities that can limit their construction programs or that control strategic transmission corridors, and financial institutions that participate in financing major Canadian construction projects. Opportunities may also arise for U.S. utilities or independent power producers to participate in Canadian power development through joint ventures with Canadian utilities. Among those firms that could be adversely impacted by Canadian imports are utilities and independent power producers attempting to sell excess capacity in the bulk power markets, nuclear and coal plant vendors, and domestic coat mining companies. Perhaps most importantly, the growth of power imports from Canada is further evidence of the competitive conditions emerging in domestic bulk power markets.

has tended to make them adjust more slowly than those of primary fuels to underlying economic trends. Consequently, the price gap between electricity and primary fuels has widened somewhat since 1980, as can be seen in figure **2-6.** As consumers react to these new relative prices, it is likely that utilities can expect greater interfuel competition in the coming decade.

As figure 2-7 shows, electricity prices have risen substantially over the past two decades. The average revenue per kWh sold by the utility industry rose from about 1.5 cents per kWh in 1970 to about 6.5 cents per kwh in 1986, in current dollars. Electricity prices for residential and commercial customers during this period were, on average, about 50 percent higher than those for industrial customers, although price trends for all three major customer classes have followed very similar patterns.

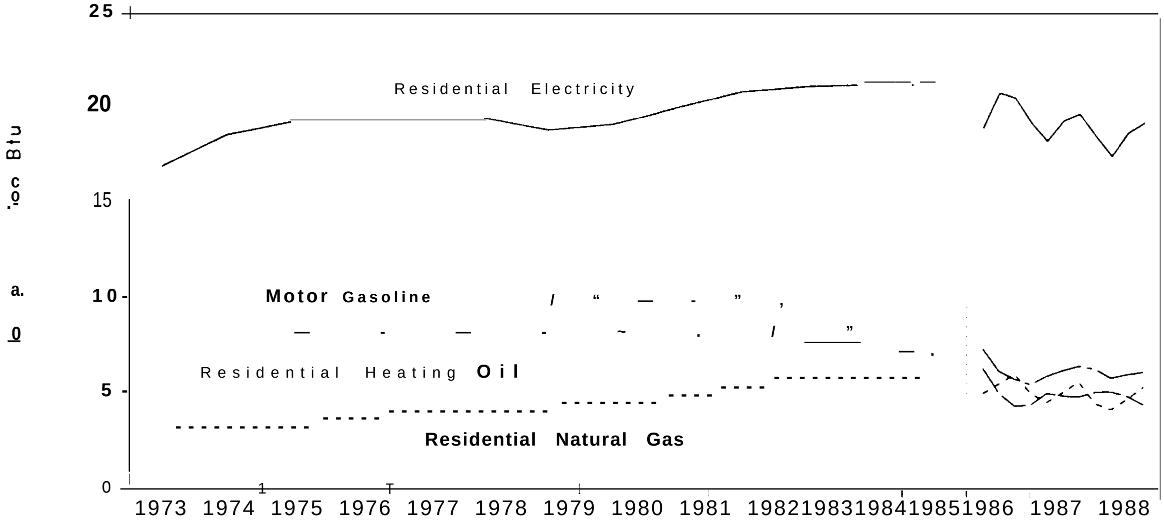
TRENDS IN INDUSTRY INVESTMENTS, BUSINESS STRATEGIES, AND STRUCTURE

Projected Industry Capacity Additions

The generating capability of the of the U.S. electric utility industry is estimated to have reached 718,056 MW as of year-end 1987.[17] Projections of future electric generation capacity additions are fraught with uncertainty because of ongoing changes in industry structure and regulation. In recent years, few utilities have been willing to commit to construction of new base-load capacity, in spite of the continued aging of the existing generating plant stock and predictions from some industry and government planners that the country faces possible shortages in the early to mid- 1990s. Meanwhile, the flow of new plant additions by utilities entering service as a result of orders placed in the 1970s is

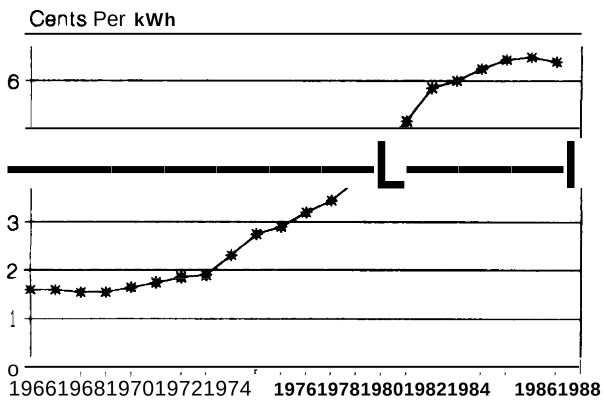
[17] Edison Electric Institute, supra note 11.

Figure 2-6-Coat of Fuels to End Users in Constant Dollars (1982 **dollars)**



SOURCE: Energy Information Administration, *Monthly Energy Review, October 1988* (Washington, DC: Jan, 26, 1969).

Figure 2-7—Average Utility Revenues Per Kilowatthour Sold, 1966-87



SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/ 1987* (Washington, DC: December 1966).

slowing to a trickle, although capacity additions by nonutility generators are increasing.

In 1988, only two utility-owned, coal-fired generating units are expected to come on line-marking a record low for the last two decades—and by 1992 only 13 utility-owned coal units totaling 8,383 MW of capacity are due to enter service. Nationwide, utilities are projected to add only 29,700 MW of capacity from all sources during this period.[18] *Through 1997, utilities and nonutility generators are projected to bring on line about 73,440 MW of capacity additions, with nuclear units accounting for about one-fourth of this total as shown in table 2-4.*[19]

Capital Spending Patterns

The *U.S. electric utility industry is expected to spend approximately* ***$27*** *billion for new facilities in 1988, according to recent industry surveys.*[20] *Industry capital expenditures have been falling in recent years since peaking in 1982 at more* than $40 billion (see figure *2-8). Annual utility industry capital spending has already fallen by about one-third (in constant dollar terms) since 1982.*

Capital spending in the electric power industry is expected to continue to fall for at least several more years before beginning to rise again sometime in the 1990s. Industry capital spending is projected to fall

[18] “Coal-Fired Power Plant Construction Hits All-Time Low, UDI Report Says,” *The Energy Report,* July 18, 1988, p. 494.

[19] North American Electric Reliability Council, 1988 *Electricity Supply and Demand for 1988-1997,* October 1988, P. 48.

[20] “1988 Annual Statistical Report,” *Electrical World,* April 1988, p. 5 1 (estimates $26,6 billion); Edison Electric Institute, *EEI Financial Info,* May 25, 1988 (estimates $25.3 billion for investor-owned utilities); and *Electric Light & Power,* January 1988 (estimates $27.5 billion).

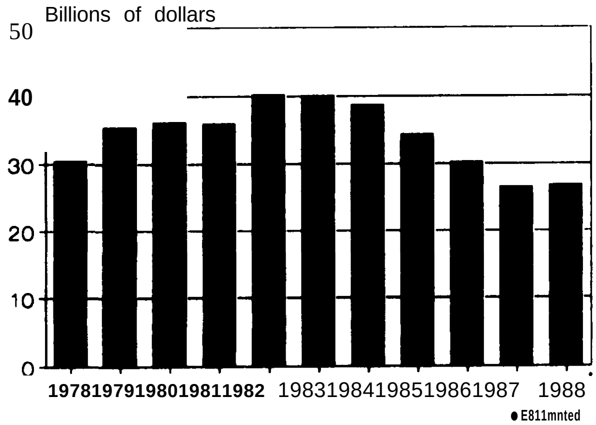
Table 2-Generating Unit Additions, 1988-97

Type	Thousands of megawatts	Percent of total
Nuclear	18.2	24.8
coal	15.4	21.0
Hydro	1.7	2.3
Oil/gas	13.6	18.5
Pumped storage	2.1	2,9
Other (utility)	2.6	
Nonutility	19.8	27.0
Total additions	73.4	100.0

NOTE: Figures are rounded.

SOURCE: North American Electric Reliability Council, *1988 Electricity Supply and Demand for* 198S- 1997, October 1988, p. 49.

Figure 2-8-Electric Utility Capital Expenditures



SOURCE: Electrical World surveys.

steadily through 1992, reaching a level of $22.2 billion, as shown in table 2-5.

The drop in industry capital spending is the result of a sharp decline in spending for new generating capacity. Capital spending for utility transmission and distribution projects has actually been rising in recent years, although the amounts are small in comparison to the decline in spending for new generation projects. The changing composition of the industry's future spending is illustrated in table 2-6, which shows different categories of forecasted capital spending by electric utilities. It is interesting to note that the 1990 forecast period is the first period where transmission and distribution spending is expected to exceed spending on new generation facilities. This change underlines the growing importance of off-system power sales, wheeling, and retail marketing to many utilities' strategic planning.

Growth in Nonutility Generation

The slowing of utility construction of new generating capacity is, to some extent, being offset by continuing growth in cogeneration and power production facilities built by nonutility entities and by unregulated utility subsidiaries. Since the passage of The Public Utility Regulatory Policies Act (PURPA) in 1978, the amount of electricity received by utilities from nonutility sources has grown dramatically. Estimates of current and projected nonutility capacity vary considerably, however, so it is difficult to measure the growth of this industry with precision. One measure of this growth can be traced through the marked increase in the number and size of filings submitted to FERC, which is charged with administering PURPA and certifying "qualifying facilities" (QFs) under the law. While these filings are not a precise indicator of the growth of nonutility power production—because a substantial number of projects filed with FERC are never brought to fruition-the growth in these filings, from 29 projects totaling 704 MW in fiscal 1980 to a cumulative total of 3,717 projects totaling 61,950

Table 2-5-Electric Utility Projected 5-Year Capital Expenditures by Function (millions of dollars)

Function	1988	1989	1990	1991	1992	5-year total
Generation	12,296	10,769	9,443	8,199	8,385	49,092
Substations	1,371	1,384	1,225	1,360	1,175	6,515
Transmission	2,558	2,376	2,397	2,795	3,092	13,218
Distribution	7,979	7,010	7,929	7,882	6,965	37,765
Other	3,281	3,106	3,118	3,054	2,622	15,181
Total	27,485	24,645	24,112	23,290	22,239	121,771

SOURCE: "Electric Utilities WIN Increase spending Plans Through 1992," *Electric Light & Power*, January 1988, p. 12.

Table 2-6--Changing Patterns of Utility Capital Investment, 1988-92

Function	1988	1989	1990	1991	1992
Generation	44.7%	43.7°/0	39.20/.	35.2°/0	37.7%
Transmission and distribution . . .	43.4	43.7	47.9	51.7	50.5
Other	11.9	12.6	12.9	13.1	11.8
Total	100.0	100,0	100.0	100.0	100.0

SOURCE: "Electric Utilities Will Increase Spending Plans Through 1992," *Electric Light & Power*, January 1988, p. 11.

MW by the end of 1987, do serve to illustrate the surge in nonutility generation.[21]

Although there is no definitive count of nonutility capacity actually on line, a recent survey by the Edison Electric Institute found 25,321 MW of nonutility capacity in operation at the end of 1986 from 2,449 projects. Of this total, 1,647 projects totaling 16,097 MW were qualifying facilities under PURPA. Cogeneration facilities accounted for 18,448 MW, or about 73 percent, of the total. Small power production capacity provided 20 percent, while other nonutility producers accounted for 8 percent. Three quarters— 18,968 MW-of the total nonutility capacity was interconnected to utility systems. A second small power database lists 1,808 QF projects, representing 24,833 MW of capacity, as operational through 1987.[22] Meanwhile, estimates of future capacity growth vary widely. Several estimates suggest that roughly 38,000 MW of nonutility capacity will be on line and selling power to utilities by 1995.[23] By the year 2000, some studies estimate that nonutility capacity will range from 40,000 to 80,000 MW.

Changes in Company Business Strategies

A number of important trends in the utility industry operating and regulatory environment have led many utilities to undertake fundamental reassessments of their corporate strategies in the 1980s. In general, utilities have begun to function more like competitive, market-driven businesses in response to an increasingly competitive and less regulated operating environment. The new, more competitive operating environment is the result of a variety of factors, including dissatisfaction with the results of traditional rate-of-return regulation, greater interfuel competition, changes in the industry's cost structure, and technological developments. (Some of the implications of a more competitive industry are shown in figure 2-9.) In the process of adapting to this new environment, the utility industry has shifted from a very homogeneous one—in which virtually all individual companies were pursuing the same strategy, namely to build new generating capacity to satisfy growing customer demand—to one in which companies are pursuing distinctly different business

Figure 2-9--Implications of Competition for Electric Utilities

Noncompetitive environment:
- Cost-based pricing
- Supply-oriented
- Regulatory allocation of cost across customer classes
- Obligation to serve all customers
- Service reliability a part of the obligation to serve
- Construction costs included in rate base
- Integrated services from power plant to customer meter
- Resources based on needs of service area
- Cost centers managing to budget

Competitive environment:
- Market-based, more flexible pricing
- Demand-oriented
- Cost management systems allocate cost by market segments
- Ability to "cherry pick" customers
- Reliability negotiated based on customer need
- Construction costs at risk
- Pressure to separate generation, transmission, and distribution services
- Resources allocated based on profitability
- Profit centers managing performance

SOURCE: Electric Power Research Institute, Competition. Pressures *for Change* (Washington, DC: June 1967).

21 "EEI: Over 25,000 MW of Non-Utility *Capacity* Was *in* Service As of 1986, " *Electric Utility Week,* Aug. 5, 1988, p.13.

22 *Energy Users News*, supra note 12, p. 1.

23 See Douglas Cogan and Susan Williams, *Generating Energy Alternatives —1987 Edition* (Washington, DC: Investor Responsibility Research Center, May 1987); and RCG Hagler, Bailly, inc., supra note 12.

strategies. These strategies can be summarized as follows:[24]

Modified Grow and Build

A number of utilities have continued to view the completion of large nuclear and coal plants, initiated in the 1970s, as their best option. This strategy is largely a continuation of that used by virtually the entire industry since its beginning. In the new utility environment, however, it typically includes increased emphasis on marketing to both retail and wholesale customers. Some utilities are also emphasizing growth through mergers or the acquisition of other utilities.

Capital Minimization

Many utilities are continuing to react to both overbuilding in the industry and regulatory uncertainty with a strategy of minimizing capital expenditures in order to minimize financial and corporate risk, Elements of this strategy include canceling plants both planned and under construction, increasing use of purchased power, participating in joint ventures if construction is necessary, selling excess capacity, rehabilitating existing plant, and devoting increased attention to energy efficiency and load-management programs.

Diversification

A *majority of investor-owned utilities have begun to diversify their business interests by investing revenues in potentially more profitable business ventures outside the electric utility business. Salomon Brothers Inc., for instance, found that 58 of the 100 utilities it follows have diversified or indicated an intention to diversify, including 24 that have formed holding companies during the past 5 years.*[25] *While the level of these expenditures is still relatively small for most utilities, a number of utilities now have sizable nonutility interests and the overall level of diversification activities in the industry is continuing to increase at a rapid pace. Pacificorp, one of the most diversified major electric* utilities, obtained nearly half of its total revenues in 1987 from operations outside of the electric utility business, including coal, gold and silver mining, regu*lated and unregulated telecommunications businesses, and financial services.*

Nontraditional Energy Technologies

Some *utilities have embarked on a strategy of significantly increasing reliance on alternative energy sources (including cogeneration, renewable energy sources, and other power supplies from nonutility sources) in an effort to reduce construction lead times and other risks from traditional power plant construction, mitigate public concerns about the environmental impacts of power generation, and shift supply risks to outside entities. Many more utilities have initiated increased research and development programs in new technologies, but they are adopting a "wait and see" attitude about major commitments to these sources.*

Outlook

At present, the utility operating environment remains quite uncertain, so it is common to find utilities pursuing more than one of these strategies simultaneously. There is a considerable amount of strategic positioning and experimentation taking place, but only a few utilities seem confident to make major strategic bets about the future direction of the industry. Most utilities seem to be attempting to hedge their risks by adopting measures to limit capital expenditures on the utility side of the business while attempting to gain experience with diversification into nonutility businesses. As market forces continue to exert a greater influence over the bulk power industry, utilities will be pressured to more clearly define and implement their strategic plans, and competition and rivalry between utilities are likely to continue to grow.

Industry Restructuring Trends

As one means of implementing their new business strategies, utilities are beginning to adopt a variety of financial restructuring measures designed to improve their operational and financial flexibility. Among the most significant types of financial restructuring evolving are sale-leaseback transactions, joint venture agreements with nonutility

[24] For further discussion of these strategies and utility implementation of them, see Scott A. Fenn, *America's Electric Utilities: Under Siege and in Transition* (New York, NY: Praeger, 1984).

[25] Mark Luftig et al., "Electric Utility Diversification," Salomon Brothers, Inc., October 1988.

companies, vertical disintegration, negotiated mergers, leveraged buyouts, and hostile takeovers.[26]

Sale-Leaseback Arrangements

One of the most common forms of restructuring that utilities are using is sale-leaseback transactions as an alternative to traditional finance methods. Utilities have used such transactions in the past for small facilities. Recently, however, they have begun utilizing lease financing in the funding or refunding of major assets. These transactions generally involve utilities selling generating plants or power lines to institutional investors and agreeing to lease back these facilities under a long-term contract, typically at very attractive rates relative to existing debt. In 1987, for example, Kansas Gas & Electric Co. arranged the sale and leaseback of the La Cygne 2 coal plant with U.S. West Financial Services for $400 million. Since the beginning of 1986, 11 power plants, including 4 nuclear plants, have been sold or put up for sale under sale-leaseback arrangements.[27]

Joint Venture Agreements

Another restructuring strategy being adopted by some utilities is the use of joint venture agreements with nonutility companies. Utilities have long been involved in joint venture arrangements among themselves to construct major generating facilities and transmission lines. In recent years, however, some utilities have begun pursuing joint ventures with nonutility entities as a way to recapitalize certain assets or to enter new businesses. Perhaps the best examples of utilities using joint ventures to enter new business areas are the joint ventures emerging between utilities and nonutility power producers in the area of cogeneration and independent power projects. In April 1987, for example, Dominion Resources Inc., the holding company for Virginia Power, announced that it was forming a joint venture with a subsidiary of CSX Corp. to develop coal- and gas-fired cogeneration projects in New England and the Middle Atlantic States. In the past 2 years, a.t least 10 such joint venture arrangements have been announced, suggesting that utilities see such ventures as an important way to participate in the evolving market for unregulated generating projects.

Vertical Disaggregation

Vertical disaggregation, or the "unbundling" of utility companies based on the functions that they perform, is another concept that a number of utilities are actively considering or pursuing. Basically, this involves the separation of all or portions of a utility's generation, transmission, and distribution functions into two or more entities that are owned and operated independently of each other. The British Government has also expressed an interest in "unbundling" utility functions to promote competition. Information on the British proposal is presented in box 2-B.

Utilities are exploring vertical disaggregation for various reasons, including:

- *fears of disallowances by State regulators for imprudent costs for new power plants entering service,*
- *a desire to attain greater flexibility in future pricing (because many disintegration proposals would allow utilities to fall under Federal jurisdiction over wholesale power sales), and*
- *as a way for the securities markets to differentiate the individual risk characteristics of the various components of the electric power business.*

State regulators have expressed considerable opposition to the major vertical disaggregation proposals that have been made to date, which include a proposal by Commonwealth Edison Co. to put three of its nearly finished nuclear plants into a separate but wholly owned generating company subsidiary that would sell power back to the utility and a proposal by Public Service Co. of New Mexico to separate its operations into independent generation and distribution companies. It should be noted that the Commonwealth Edison Co. proposal has been defeated and the Public Service Co. of New Mexico proposal withdrawn.

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[26]For a detailed discussion of utility restructuring activities, see Scott A. Fenn, "Competition and the Role of the Capital Markets in Restructuring the Electric Power Industry," OTA working paper, December 1987; and Scott A. Fenn, Mergers *and Financial Restructuring in the Electric Power Industry* (Washington, DC: Investor Responsibility Research Center, May 1988).

[27]Both investor-owned utilities and electric cooperatives have used sale-leaseback arrangements.

Box 2-B-Creating a Competitive Generation Industry in Great Britain

In February **1988,** Britain's Department of Energy proposed to privatize its electric utilities in England and Wales. The proposal is aimed at promoting competition by eliminating the industry's monopoly on generation.

Current Industry Structure

The Central Electricity Generating Board (CEGB) produces almost all (95 percent) of the power used in England and Wales today. It also owns and operates the transmission grid, which includes interconnections with Scotland and France. The CEGB plans capacity additions, specifies plant design and performance requirements, and supervises construction. The CEGB sells its power to 12 nationalized distribution entities, called area boards, which distribute the electricity to customers. According to the government, the CEGB is "an effective monopoly in areas where this is unnecessary and harmful to the interests of customers,'"

Proposed Changes

The government's proposal separates generation from transmission and distribution. The CEGB will be divided into two competing generation companies and an independent national grid *company. The two generating companies-National Power and Power-Generation—will own 70 percent and 30 percent of* existing plants respectively, The 12 area boards will be privatized as licensed distribution companies that can purchase power from a number of sources, including the two newly created generation companies, private generators, or foreign suppliers. Distributors also may construct their own generating units or enter into joint ventures to produce electricity. The area distributors will jointly own and control the new National Grid Company. The National Grid Company will be responsible for coordinating power plant operation and for acquiring new capacity through competitive bidding.[2]

Contracts will provide the basis for business relationships among generators, distributors, and the grid company. The distributing companies can contract for power supplies with the generators directly or through the grid company. In both cases, the Grid Company would have to be involved in order to ensure the reliability of the entire system. The national government will regulate prices in the retail market but not in the wholesale market. Adjacent regional distributors will be free to compete for large customers.[3]

Furthermore, the government proposal specifies that generation, transmission, and distribution companies be licensed by the Energy Department. The four kinds of licenses proposed cover: 1) companies that control low-voltage distribution lines, 2) companies that have more than 50 MW generation capacity and sell to the wholesale market, 3) companies that sell to a specific user or situation, and 4) the National Grid Company.[4]

R&D facilities will be divided among the three new companies. These labs will conduct research for all three new companies until the official split in the early 1990s. After that, companies will conduct their own independent research, although some research may continue to be jointly funded.[5]

The Department of Energy is seeking approval for its proposal (in the form of a' 'Royal Assent") by summer 1989,

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[1]pn"vdislw *Electricity—The Government's Proposals for the Privatisation of the Electricity Supply Industry in England and Wales,* presented to Parliament by the Secretary of State for Energy by Command of Her Majesty, February 1988.

[2]Ibid.

[3]Ibid.

[4]"Fair Play: British Define Terms of New Licenses for Generating Companies," *Energy Daily, Dec. 8, 19S8,* p. 3.

[5]"British Tackle Tricky Task of Dividing Electricity R&D After privatization, " *Energy Daily,* Nov. 18, 1988, p. 1.

Negotiated Mergers, Acquisitions, and Leveraged Buyouts

Negotiated or "friendly," mergers between utilities are likely to be one of the most significant types of utility restructuring activity. For example, a merger between the Pacificorp and Utah Power & Light Co. has recently been completed and a proposal by SCEcorp. to merge with San Diego Gas & Electric Co. is being pursued by the companies but is experiencing opposition. Hostile takeovers and acquisitions are likely to be difficult in the utility industry because of regulatory concerns, but it appears possible that some hostile transactions will *succeed, particularly in cases where the strictures of the Public Utility Holding Company Act of 1935 are not invoked. Leveraged buyouts (LBO), in which a small group of investors buy out a company's public shareholders at a premium, usually using the target company's asset base or cash flow to support a highly leveraged capital structure, have not been a factor in the electric power industry to date, although there have been at least two attempts to take a utility private in an LBO-type transaction.*

Although actual merger and acquisition activity has not lived up to many people's expectations, the pace of such activity has clearly begun to quicken, with about 10 merger or acquisition proposals announced in the last 3 years.[28]

Public and Private Power Takeover Battles

Another type of restructuring activity underway involves attempts by city or State governments to gain control of investor-owned utilities, and attempts by investor-owned utilities to gain control of publicly owned utilities. The catalyst for a number of these takeover situations of the first type appears to be the prospect for dramatic rate increases related to nuclear plant construction or operation. A number of city governments are looking at the option of creating municipal utilities to take over investor-owned electric distribution systems, although this option was made considerably less attractive by the passage of tax legislation late in 1987 that largely precludes State and local governments from using tax-exempt financing to acquire private electric utility assets. Among the large cities studying the municipal takeover option are Chicago, New Orleans, and Albuquerque. There also appears to be considerable interest, however, in what are essential] y buyouts of municipally owned and cooperative electric systems by the investor-owned sector.

Measures of Financial Health

Declines in utility industry capital spending have had a favorable impact on the industry's overall financial performance and health in recent years. In fact, by some measures, the industry's financial position is now stronger than it has been since the industry's "golden age" of the 1950s. Among the indicators commonly used to monitor the industry's financial health are internal cash generation, capitalization ratios, bond ratings, and trends in returns on equity and rate decisions.

Internal Cash Generation

The *decline in industry capital spending is particularly significant because it is Occurring at a time when the power industry's internal cash generation capability is climbing—meaning that less and less of the industry's capital spending needs to be externally financed.*

As shown in figure 2-10, Salomon Brothers Inc. predicts that the utility industry will finance 77 percent of its construction expenditures from internal funds in 1988, 85 percent in 1989, and 95.5 percent in 1990-up from only about 33 percent in 1980. In addition, Salomon Brothers estimates that by 1990,40 percent of all electric utilities it monitors will be generating 100 percent of the capital they need for construction from internal funds.[z9]

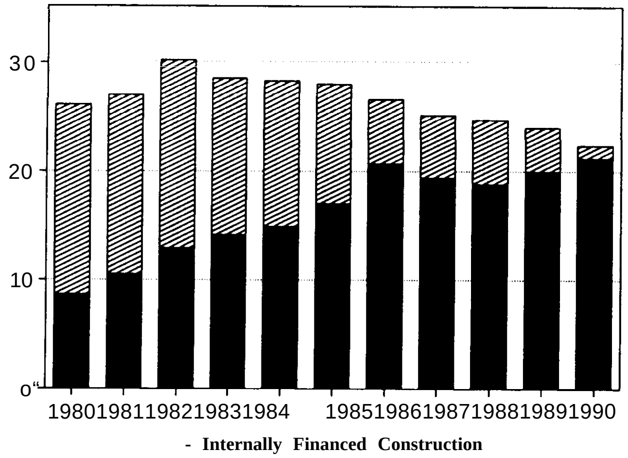
Capitalization Ratio

The improvement in the industry's financial position in recent years can also be seen in the industry's capitalization ratios. As shown in table 2-7, the percentage of common equity in the industry's capital structure is now at its highest level in more than 20 years, and is continuing to improve. In fact by this measure, the industry's financial position is now the strongest it has been since the 1940s.

28 Among the utilities involved i, merger and acquisition activities in recent years are Cleveland Electric Illuminating Co. and Toledo Edison CO. (merger announced in June 1985); Public Service Co. of Indiana (informal LBO bid by outside investment group in October 1986 was spumed by management); Newport Electric Co. (hostile tender offers in 1986 and 1987 resulting in new ownership); Pacificorp and Utah power & Light Co. (merger announced in August 1987 and approved by FERC in October 1988); Pacific Gas & Electric Co. (proposal to buy Sacramento Municipal *Utility District* made in September 1987 and later dropped); The Southern Co. (agreed to acquire Savannah Electric & Power in October 1987); Public Service Co. of New Hampshire (has received overtures from severat New England utilities after filing for bankruptcy in March 1988); SCEcorp and San Diego Gas& Electric (merger agreement reached in November 1988 ending San Diego Gas & Electric's previous agreement to merge with Tucson Electric).

2(? Salomon Brothers Stock Research, *Electric Utility Quality Measurements—Quarterly* Review, Jan. 26, 1989, p. 11.

Figure 2-10-internal Cash Generation and Construction by Investor-Owned Electric Utilities, *1980* (billions of dollars)



E = estimate.

SOURCE: Salomon Brothers Stock Research, "Electric Utility Quality Measurements, Quarterly Review," Jan. 26, 1969.

Bond Ratings

Although the utility industry's fundamental financial position has improved substantially over the past decade and is now quite strong, there are at least some indications that this improvement may be offset somewhat by a more risky operating environment. The industry's average bond ratings, for instance, have not improved over the past decade, primarily because ratings agencies believe that improvements in the industry's fundamental financial condition have been offset by increased business risk resulting from the growth of competitive forces and new regulatory approaches. During 1987, all four major utility bond ratings agencies downgraded the ratings of more utility debt securities than they upgraded. The bankruptcy filing by Public Service Co. of New Hampshire in 1988, the first major private electric utility bankruptcy in more than 50 years, may further increase perceptions of risk in this industry by securities ratings agencies. Moreover, the overall improvement in the utility industry's financial position has not been spread evenly throughout the industry. Utilities with nuclear plants still under construction, in particular, appear to remain quite vulnerable, as is reflected in the fact that five such investor-owned utilities carry bond ratings that are below investment grade.

Allowed and Earned Returns

In addition, allowed and earned rates of return in the industry are falling as regulators adjust to the lower interest rate environment of the mid- 1980s. As figure 2-11 shows, allowed returns on equity for the industry fell from nearly 16 percent in 1982 to just below 13 percent in 1988—although the spread between utility allowed returns and bond yields has actually widened somewhat during this period. Earned returns, the amounts actually earned by utilities, have also been falling since 1984 and actually exceeded allowed returns in 1987.

Trends in Rate Decisions

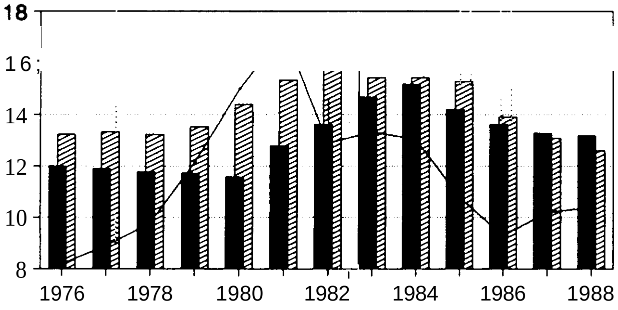
Recent trends in electric rate case actions-shown in table 2-8--confirm that many regulators believe that the industry's rate of return is, if anything, more than adequate. Rate increases granted by regulators have been dropping sharply in recent years due to declining interest rates, lower allowed returns on equity, and decreases in State and Federal income tax rates. In 1987, in addition to approving $2.3 billion in rate increases, regulators ordered more than $1.4 billion in annualized electric rate decreases-

Table 2-7-Capitalization Ratios of Electric Utility Industry, 1965-87

Capitalization	1965	1970	1975	1980	1985	1987
Common equity	38.3%	34.1 %	34.3%	36.50/o	41.470	41 .5%
Preferred and preference stock			12.1	11.7	9.5	7,9
Long-term debt	50.6%	53.0	50.8	48.6	48.1	48.2
Short-term debt	1.8	3.4	2.9	3.2	1.0	2.4

SOURCE: Leonard Hyman, *America's Electric Utilities: Past, Present and Future* (Arlington, VA: Public Utilities Reports, 1988 edition); and Salmon Brothers Stock Research, "Quarterly Review," Apr. 15, 1966.

Figure 2-n-Electric Utility Allowed and Earned Returns on Equity, 1976-87



SOURCE: Salomon Brothers Stock Research, "Electric Utility Regulation—Semiannual Review," Sept. 6, 1986.

the first time ever that rate decrease amounts have surpassed $1 billion.[30]

THE EXISTING REGULATORY STRUCTURE

In the United States, Federal, State, and local governments exercise jurisdiction over the activities of the electric power industry. Like other businesses, the electric power industry is subject to laws and regulations governing financial transactions, employment practices, health and safety, and environmental impacts. But unlike other businesses, it (along with segments of the transportation and telecommunications industries) is subject to the additional requirements of public utility regulation. The electric power industry is one of the most heavily regulated *with virtually all aspects of power generation, transmission, and distribution under the oversight of State and/or Federal agencies.*

The Concept of a Public Utility

Because their activities provide vital services to businesses and communities, public utilities enjoy a special status under State and Federal law that distinguishes them from other enterprises. This status confers specific rights and obligations. Generally, a public utility has:

- *an obligation to serve all customers in its service area (within its available capacity limitations);*
- *an obligation to render safe and adequate service, including meeting foreseeable increases in demand;*
- *an obligation to serve all customers within each service class on equal terms (i.e., with no unjust or undue discrimination among customers); and*
- *an obligation to charge only a ''just and reasonable" price for its services .31*

In return for assuming these obligations, the public utility enjoys certain "rights." First, the utility has a right to reasonable compensation for its services, however recovery of a specific authorized rate of return is not guaranteed.[32] *Second, through its franchise and certificate of public convenience and necessity, the utility generally is protected from competition from other enterprises offering the same service in the same service territory. Third, the public utility has a right to conduct its operations and render service subject to reasonable rates and regulations. Finally, in many States, public utilities can exercise the right of eminent domain to condemn and take private property for public use where necessary to provide adequate service, subject to the requirement of just compensation to the owner.*[33]

Federal and State Regulation of Electric Power

Both State and Federal laws define any entity that sells electricity as a public utility[34] *thus bringing*

[30] Edison Electric Institute, "Rate Decrease Amounts Top One Billion Dollars in 1987," *EEI Financial Info*, Apr. 12, 1988.

[31] Charles F. Phillips, Jr., *The Regulation of Public Utilities Theory and Practice* (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 106.

[32] Regulatory authorities cannot force a utility to operate at a loss. However, at times, the utility may not actually earn its authorized rate of return because of adverse economic conditions or poor business judgment. The rate will be upheld by the courts if it is determined to be reasonable.

[33] Phillips, supra note 31, p. 107.

[34] See, for example, the definition of an electric utility in the Federal Power Act as: "any person or State agency which sells electric energy, " 16 U.S. C. *7%(22),* and the definition of "electric utility company" in the Public Utility Holding Company Act as 'any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale, " 15 U.S.C. 79b(a)(3).

Table 2-8 Annual Electric Rate Case Actions, 1983-87

	Number of rate actions		Total amount (millions of dollars)	
Year	Increases	Decreases	Increases	Decreases
1983	241	17	5,373.4	59.1
1984 , ...	186	19	4,745.0	175.0
1985	127	17	4,989.7	129.7
1986	104	21	2,880.9	383.0
1987	86	117	2,304.3	1,441.8

SOURCE: Edison Electric Institute, 1988.

generators and retail distributors of electricity under regulation. Jurisdiction over the activities of electric utilities is split between the Federal Government and State agencies (including local governments). This division reflects both the historical growth of electric utility regulation in this country, which began at the State and local level, and the Federal Government's constitutional authority over interstate commerce. Most generators are now subject to both Federal and State rate regulation.

The split jurisdiction was formalized with passage of legislation in 1935 that gave the Federal Power Commission authority over interstate transmission and sale of electric power at wholesale.[35] *The creation of a strong Federal role in the regulation of interstate activities in electric power was prompted by the 1927 Supreme Court ruling that State regulatory agencies were constitutionally prohibited from setting the prices of electricity sold across State lines because it would violate the Commerce Clause.*[36] *This decision created a gap in effective regulation of electric utilities.*

Federal regulation of interstate and wholesale sales was initially seen as a supplement to State authority to fill a gap where existing State regulation had proven ineffective or unconstitutional. But as interconnections among utilities grew and long-distance transmission increased, virtually all electric power moving over transmission lines was viewed as being in interstate commerce and hence subject to exclusive Federal jurisdiction. Ever more expansive interpretations of Federal jurisdiction have now arguably limited State jurisdiction over wholesale sales and wheeling transactions, even when they involve instate parties.[37]

Federal Regulation

The major Federal regulatory agency for electric utilities is FERC, the successor to the Federal Power Commission. FERC is a five-member independent regulatory commission within the Department of Energy. It derives its primary authority from the Federal Power Act, as amended.[38]

FERC has authority over the prices, terms, and conditions of wholesale power sales involving privately owned power companies and of transmission of electricity at wholesale.[39] Because the power systems in the ERCOT region of Texas, and in Alaska and Hawaii are not synchronously connected to power systems in other States, FERC does not have jurisdiction over most power transactions in these States. FERC must approve sales and mergers of public utilities under section 203 of the Federal Power Act.[40] It has jurisdiction *over the issuance of securities and indebtedness of electric utilities.*[41]

[35] Title II of the Public Utility Act of 1935, known as the Federal Power Act, 16 U.S.C. 791a.

[36] *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric CO., 273 U.S.* 83 (1927).

[37] See *Federal Power Commission* v. *Southern California Edison Co.*, 376 U.S. 205 (1968), also known as *City of Colton v. Southern California Edison Co.* See also *Florida Power & LightCo., 29* F.E.R.C. 61,140 (1984) in which FERC asserted exclusive Federal jurisdiction over virtually all transmission service in Florida.

'1816 U.S.C. 791a.

[39] See secs. 201 and 205 of the Federal Power Act, 16 U.S.C. 824a and 824d, respectively.

[40] 16 U.S.C. 824b.

[41] 16 U.S.C. 824c.

FERC also oversees power pools and interconnections among utilities.[42]

As part of the responsibilities inherited from the Federal Power Commission, FERC oversees and licenses nonfederal hydroelectric projects on navigable waters under Title I of the Federal Power Act,[43] In addition, FERC approves the rates for public power sold and transported by the five Federal Power Marketing Agencies.

The Public Utility Regulatory Policies Act of 1978 (PURPA) amended the Federal Power Act and gave FERC expanded responsibilities for the encouragement of cogeneration and small power production using alternative energy technologies.[44] The goals of PURPA were to advance: 1) conservation of electric energy, 2) increased efficiency in electric power production, and 3) achievement of equitable retail rates for consumers. This was to be achieved in large part by requiring utilities to interconnect with and buy power from cogenerators and small power producers that met standards established by FERC. This requirement was the first major Federal move to open up electricity markets to nonutilities. At the same time, PURPA exempted these qualifying facilities (QFs) from most of regulatory burdens applicable to public utilities under Federal and State law in order to reduce the institutional barriers to QF development.

PURPA requires that electric utilities must offer to purchase electricity from QFs at their avoided costs and to sell electricity to QFs on nondiscriminatory terms and conditions. In addition, utilities must offer to interconnect and operate in parallel with QFs. The rates paid for QF power must: 1) be just and reasonable to electric consumers and in the public interest, 2) not discriminate against QFs, and 3) not exceed the cost of electric energy that the utility would generate itself or purchase from another source.[45] The rates charged to QFs for supplemental or backup power must be just and reasonable and not discriminate against QFs.

FERC was given the lead responsibility to issue regulations and guidelines implementing PURPA, but State regulatory commissions were given the primary authority for setting avoided cost rates and conditions for PURPA purchase and sale contracts. FERC has continuing responsibility for overseeing PURPA implementation and in March 1988 issued three notices of proposed rulemaking (NOPRs) that would alter the original PURPA regulations to correct perceived shortcomings in State avoided cost determinations and to allow the use of competitive bidding in setting QF payments.

In addition to the interconnection and purchase requirements, PURPA also gave FERC explicit, though severely limited, authority to order an electric utility to transmit over its lines power produced by another generator.[46] Whether FERC has any inherent authority to order wheeling services under other provisions of law is a matter of some controversy and debate. Until recently, FERC and many legal experts concluded that FERC had no wheeling authority under the Federal Power Act because Congress had expressly rejected such a provision in passing the Act.[47] Recently, it has been suggested that FERC has the inherent authority to require a utility to wheel power for others as a condition of approving wholesale rates, mergers and

[42] 16 U.S.C. 824b.

[43] 16 U.S.C. 791a to 823.

[44] Public Law 95.615, 92 Stat. 3117, Nov. 9, 1978.

[45] Public Law 95-615, sec. 210, 92 Stat. 3144, 16 U.S.C. 824a-3.

[46] PURPA secs. 203 and 204 amended the Federal Power Act to add new sea. 211 and 212, codified as 16 U.S.C. 824j and 16 U.S.C. 824k, respectively.

[47] In *Otter Tail Power Co. v. United States*, 410 U.S. 366, at 375 (1973), the U.S. Supreme Court noted in dicta that the Federal power Act did not grant any authority to order wheeling, but that wheeling could be ordered by the Federal Courts as a remedy under the antitrust laws. A similar conclusion on wheeling authority is reached in National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers*. September 1987, pp. 52-68, although the author notes that FERC may have some as yet untested authority to order wheeling as a remedy for anti-competitive behavior under sees. 205 and 206 of the Federal Power Act, id. at note 45, p. 64. See also *Florida Power& Light Co. v. FERC*, 660 F. 2d 668 (5th Cir. 1981), p. 679. The report of the Conference Committee on PURPA is vague on the extent of any existing wheeling authority FERC might have outside of sees. 211 and 212 and notes that PURPA is not intended to affect existing authority, House Conference Report 95-1750, to accompany H.R. 4018! 95th Cong., 2d sess., Oct. 10, 1978, pp. 91-95, 1978 U.S. Code Congressional and Administrative News 7825-7829.

acquisitions, or participation in competitive generation markets.[48]

The Public Utility Holding Company Act of 1935 (PUHCA) was passed in conjunction with title II of the Federal Power Act.[49] It gave the Securities and Exchange Commission (SEC) broad authority over the structure, finances, and operations of public utility holding companies. PUHCA was enacted in response to widespread concern over the influence of a handful of large interstate utility holding companies that by 1932 controlled over 75 percent of the private electric utilities. The holding companies' complex corporate structures and interlocking business arrangements had frustrated both State and Federal oversight of their activities, led to substantial investment fraud, and weakened or bankrupt a number of local gas and electric utilities.[50] PUHCA was intended to limit severely the use of the holding company structure and to force the regional consolidation of the existing large multi-State holding companies.

Under PUHCA any company that owns or controls more than 10 percent of the voting securities of a public utility is considered to be a public utility holding company. An electric utility company is any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale. The holding companies are subject to extensive regulation of their financial activities and operations under PUHCA. Public utility holding companies can qualify for an exemption from the most stringent regulatory oversight of PUHCA if they operate wholly within a State, or in contiguous States, or the company is only incidentally a holding company, is primarily engaged in a business other than the public utility business, and does not derive a material part of its income from the public utility business.[51] Non-exempt entities are registered holding companies and are limited in their operations to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate [there]to." Integration means that the utility operations are limited to a single area or region of the country. Registered holding companies must obtain SEC approval of the sale and issuance of securities; transactions among their affiliates and subsidiaries; and services, sales, and construction contracts. In addition the companies must file extensive financial reports with the SEC. In contrast, exempt companies need only file limited annual reports with the SEC.

The REA also exercises some regulatory oversight of cooperatives holding Federal loans. The extent of this regulation is primarily directed at assuring the financial viability of the cooperative entities to repay their Federal loan obligations. At times the REA has ordered cooperatives to raise rates to their customers to cover costs.

State Regulation

State regulation of electric power is diverse and only broad generalizations can be made. State regulation is conducted by multimember boards or commissions whose members may be either appointed or elected. The utilities under State jurisdiction vary-some States regulate all utilities, including publicly owned systems and cooperatives, while others limit jurisdiction to investor-owned systems and leave regulation of municipal systems to local

[48] In *Re Utah power & Light Co., eta/.* (Oct. 26, 1988), FERC approved the merger of Utah Power & Light Co. into Pacific Power & Light Co. subject to the condition that the merged companies provide firm wholesale transmission services at cost-based rates to any utility that requested such service. The condition was necessary to prevent the future exercise of market power by the new company to foreclose access by competitors to bulk power markets. The decision was reached under sec. 203 of the Federal Power Act which requires commission approval of mergers and acquisitions. The extent of any inherent conditional authority of FERC to order wheeling under other sections of the Federal Power Act is still uncertain. FERC has solicited comments on imposing 'wheeling in" and" wheeling out" conditions on utilities participating in bidding programs. Notice of Proposed Rulemaking on Regulations Governing Bidding Programs (18 CFR Parts 35 and 293), Docket No. RM88-5-000, Mar. 16, 1988, pp. 87-91. "Wheeling in" would require a utility bidding on the capacity needs of another utility to agree to provide firm transmission services to the purchasing utility for successful bidders that are located in its service area or that can reach one of its interconnection points. "Wheeling out" would require a utility bidding to supply its own capacity needs to provide firm transmission services in and through its service area to unsuccessful bidders that wished to sell to another wholesale purchaser. For an expansive exposition of the argument that FERC has and is required to use conditional wheeling authority to deal with potentially anti-competitive situations, see the comments of the Electricity Consumers Resource Council et al. filed in Docket RM88-5-000, July 18, 1988, and Reply Comments filed Sept. 13, 1988.

[49] Act of Aug. 26, 1935, c. 687, Title 1, sec. 33,49 Stat. 438,15 U.S.C. 79.

[50] For a discussion of the structure and influence of the holding companies, see Leonard S. Hyman, *America's Electric Utilities" Past, Present and Future,* 3d ed. (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 71-83.

[51] 15 U.S.C. 79c.

governments. In addition to control over prices, States or local governments control market entry and determine who may operate as an electric utility by granting certificates of public convenience and necessity and awarding franchise territories.

All States regulate retail prices of electricity. In setting retail rates, State regulators must approve a level that provides a reasonable rate of return to the utility which will cover its costs of providing service plus a profit. Under various formulations, many States require that utility investments be determined to be prudent and 'used and useful " before they can be recovered through retail rates. Some States allow recovery for plants under construction, while others defer recovery until the plant is actually in operation.

Many States also regulate other aspects of utility operations in some detail including planning and determination of resource needs including new generation, bulk power purchases, and construction of transmission and distribution facilities.[52] A number of States regulate the siting of utility facilities either through the public utility commission or a separate siting agency .53

Several States have included wheeling provisions in their competitive bidding programs. However, the extent to which State regulatory authorities can require wheeling is uncertain because of the possibility of preemption by FERC under section 201(b) of the Federal Power Act.[54] FERC has asserted authority over the rates and conditions of transmission in interstate commerce and has argued that this preempts State regulation of these matters.[55] But FERC has so far declined to resolve the issue of whether FERC jurisdiction also preempts State authority to order wheeling.

While States have exclusive retail rate jurisdiction, under the Narragansett doctrine they must generally pass through wholesale rates approved by FERC.[56] The extent to which FERC determinations of the reasonableness of wholesale rates preempts State consideration of the retail impacts of those same rates is a matter of some controversy.[57] The strain arises because State regulatory programs and the considerations used in setting rates are generally far more extensive than FERC's. In some cases, requiring States to adopt without question FERC'S wholesale rate determinations in setting retail rates would preclude States from exercising their own regulatory authority over issues normally within their jurisdiction.

The major limitation on Federal preemption is found in the Pike County exception, which affirmed the right of a State commission to examine the prudence of a wholesale power purchase contract and to disallow the pass through of FERC-approved wholesale costs if lower cost power supplies were available elsewhere.[58] The issue of whether States can review the prudence of wholesale power contracts will become especially critical if proposals to create a competitive generating sector result in utilities relying more heavily on bulk power purchases that, except for QF transactions, fall within FERC's jurisdiction. The vitality of the Pike County exception has been cast into doubt by the Supreme Court's 1988 decision in Mississippi Power& Light Co. v. Mississippi ex rel. Moore that rejected State efforts to deny a rate increase based on FERC's

[52] For a summary of State requirements for utility planning and forecasting requirements, see Public Utilities Commission of the State of Ohio, *Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey by the National Governors' Association Task Force on Electricity Transmission,* OTA contractor report, July 1988.

[53] See the discussion of State siting requirements in ch. 7 of this report.

[54] 16 U.S.C. 824b. See discussion of this issue in National Regulatory Research Institute, supra nOte 47, pp. 70-78.

[55] *Florida Power & Light Co. and* f. *lorida Public Service Commission, et al., 29* F. E.R.C. 61,140 (1984). See also the remarks of FERC Commissioner Charles Trabandt that FERC may not acquiesce in State efforts to require wheeling under competitive bidding programs, 'Trabandt: Generic Action by FERC Unlikely on Transmission Access, " *Electric Utility Week,* Feb. 13, 1989, pp. *1-2.*

[56] This rule was set forth in *Narragansett Electric Co.* v. *Burke,* 119 R.I. *559,381* A.2d 1358 (1977), cert. denied, 435 U.S. 972 (1978), one of a series of State court decisions that recognized Federal preemption.

[57] For discussion of these issues see the following: Ronald D. Jones, ''Regulations of Interstate Electric Power: FERC versus the States," 2 Natural *Resources & Environment 3,* Spring 1987; LYM N. Hargis, "The War Between The Rates 1s Over, But Battles Remain," 2 *Natural Resources & Environment 7,* Spring 1987; and Bill Clinton, Robert E. Johnston, Walter W. Nixon, 111, and Sam Bratton, ''FERC, State Regulators and Public Utilities: A Tilted Balance?" 2 *Natural Resources& Environment* 11, Spring 1987.

[58] *Pike County Light & Power Co.* v. *Pennsylvania Public Utility Commission,* 77 Pa. Comm'w. 268, 465 A. 2d 735 (1983). The potential exception was apparently accepted by FERC in Pennsylvania Power& *Light Co.,* 23 F. E.R.C. 61,005 (1983) and noted by the U.S. Supreme Court in *Nantahala Power & Light Co. v. Thornburg, 106* U.S. 2349 (1986).

allocation of the costs of a nuclear unit built to meet the needs of an integrated interstate holding company system on the grounds that the local subsidiary's participation in the project was imprudent.[59] *A State prudence inquiry was preempted even though FERC had not examined the issue during wholesale rate proceedings. The State regulators' only recourse is to challenge the prudence of the wholesale arrangements before FERC. Whether the Mississippi Power & Light decision is limited to the particular situation of interstate holding companies or whether it marks further limitations on the powers of State regulators is not yet known. Resolution of this controversy over conflicting Federal and State jurisdictional claims will be one of the major public policy issues in any transition to a more competitive electric power industry.*

[59] *Mississippi Power & Light* Co. v. *Mississippi ex rel. Moore*, No. 86-1970, June 24, 1988.