THE FEDERAL ROLE IN THE SEARCH FOR SOLUTIONS

The federal government has only a small role in allocating the large costs arising from the utility construction campaigns of the 1970s. Ratemaking has traditionally been a state prerogative, in which the costs and benefits of electric utility investments are apportioned between the utility's investors and its customers. Federal actions might be appropriate, however, in addressing longer-term concerns about risk, uncertainty, and investment inefficiency in the utility industry. In part, this is because the federal role in utility ratemaking has increased as more electricity is traded across state boundaries. The portion of electricity sales subject to regulation by the Federal Energy Regulatory Commission (FERC) has increased from about 5 percent in the 1970s to about 29 percent in 1984. Federal authority is likely to grow further to the extent that utilities meet new demand with power purchased from neighboring utilities rather than their own investments in new power plants.

In addition, the federal government is directly involved in the choice of fuel and generating technology. The Powerplant and Industrial Fuel Use Act of 1978, as amended, prohibits the construction of new, large power plants that burn natural gas. The Public Utility Regulatory Policy Act of 1978, as amended, provides incentives for industrial cogeneration to supplement or even displace power plants owned by electric utility companies. [2] Finally, the Public Utility Holding Company Act of 1935, as amended, has been instrumental in shaping the structure of the industry. Thus, the federal government is already heavily involved in shaping long-run incentives for investment efficiency.

For both the short-term problem of cost allocation and the long-term one of investment efficiency, this study examines the following questions:

- What are the common causes for utilities' financial stress and do sufficient similarities exist across utilities to allow a generic solution to the problem?

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2. Cogeneration refers to the sale of excess power generated by a privately or commercially owned company to a regulated utility. For example, a business that produces electricity for plant operations (such as a pulp and paper mill) could act as a cogenerator, and sell its excess power to the utility in its service area. This excess power would then enter the utility's "grid," becoming part of its total electricity supply.

- What options are available to utilities, state regulatory commissions, and the state and federal governments to relieve financial stress, prevent bankruptcy, or lessen the effect of potential utility failures?

- What options are available to help ensure that efficient, low-cost electricity capacity is built when needed?

CHAPTER II

THE CHANGING FINANCIAL CONDITIONS OF THE PRIVATE ELECTRIC UTILITY INDUSTRY

This chapter discusses the changing financial conditions of the investor-owned utility industry over the past two decades. Twenty years ago, the costs of building new power plants tended to be predictable and, most important, declining. The goal of regulators--to provide low-cost electricity to consumers--and the goal of utilities--to earn a fair return on investment for their stockholders--were in relative harmony. Through a series of events in the 1970s, however, the costs of new construction rose dramatically and the growth in demand for electricity dropped unexpectedly. In many cases, state regulators were reluctant to pass on to ratepayers the costs of expensive--and sometimes excess--capacity. Absorbing these costs caused a decline in the financial position of the private utility industry. Although most firms have recovered substantially from the industry's poor financial performance of 1980, some utilities currently engaged in new plant construction continue to experience significant liquidity shortages. Several firms, in fact, have been forced to omit common stock dividends to sustain operations.

CURRENT COMPOSITION OF THE INDUSTRY

The electric utility industry possesses about 600,000 megawatts (Mg) of generating capacity. Coal was the primary source of electricity generation in 1984, providing 43.6 percent of total U.S. capacity. Oil and natural gas accounted for almost one-third (32.2 percent) of total capacity. Nuclear generation in 1984 amounted to 10.7 percent of total capacity, with 84 reactors licensed to operate. Hydro power constituted about the same percent (10.4 percent) of total capacity as nuclear generation. Other sources, including pumped storage and geothermal, accounted for 3 percent of capacity in 1984. Because of their lower relative operating costs, however, coal and nuclear plants supplied disproportionately more electricity--55.9 percent and 15.9 percent, respectively--than would be suggested by their relative shares of generating capacity. 1/

1. North American Electric Reliability Council, *Electric Power Supply and Demand 1984-1993: 1984 Annual Data Summary Report.*

Not all regions have the same access to sources of power, and great variations exist in generating capacity by fuel type across the country. Coal is the dominant source of power (exceeding 50 percent) in the Mid-Atlantic, the Mid-West and the Southeast.[2] Nuclear power accounts for between 6 percent and 21 percent of the electricity generated in these regions. Oil exceeds 20 percent of the generating capacity only in the Mid-Atlantic and the Northeast. In the Southwest, gas is dominant while hydro power is important mostly in the West.

Physical and Financial Integration

Partly because of the high capital investment costs, the investor-owned electric utility industry is significantly integrated both financially and physically. The financial integration among utilities is apparent from the number of joint partnerships undertaking new plant construction and the number of publicly owned utilities participating in these partnerships. About half of all new nuclear-power plants under construction, for example, involve joint ownership by at least two utilities, with public utilities (such as electric cooperatives) often included among the partners. These joint efforts allow utilities to pool their resources, without entering into a formal merger agreement.

The electric power "grid" is evidence of physical integration. Grids provide common transmission links among plants and over large regions spanning several states. Such interconnection allows firms to sell their excess capacity to firms needing power.[3] The frequency of these interstate transactions have increased over the last decade, and now represent about 29 percent of electricity sales. Three major grids serve the continental U.S. market. For example, the eastern two-thirds of the United States, is served by one grid.

THE ERA OF STRONG UTILITY GROWTH

From 1950 to 1970, electric utilities experienced a strong and stable period, marked by steadily increasing returns on equity, relatively high stock prices,

2. Ibid., p. 79.

3. See Department of Energy, *The National Power Grid Study* (1980). In fact, excess power is not necessarily "shipped" to far away places. If a plant in one locale can spare power to another locale far down the transmission link, each intermediate locale between the sending and receiving areas simply passes on the power as it is received from the plant up the line. Thus, the excess power is eventually supplied to the needy area.

and robust growth in electricity demand. With economies of scale and technological advances encouraging larger and larger plants, and with integration within and across firms improving efficiency, generating capacity more than quadrupled while real prices decreased by about 30 percent. Reserve margins--the difference between total generating capacity and anticipated peak demand--were comfortably maintained at an average of 22 percent. 4/ These margins helped ensure a reliable supply of electricity even if demand increased faster than expected.

With declining real costs and prices, the goals of both the state regulators and the electric utilities were accommodated quite easily. Rate hearings needed to be held much less frequently than today, and the subject of such hearings often was not how much to raise prices, but how much to lower them.

Regulatory requirements affecting utilities were also considerably less complex during this period. Laws concerning the environment and power plant siting had little impact before 1970. Partly as a result of this benign regulatory environment, the average construction period for new baseload plants in the 1960s was about six years, compared with eight to twelve years today. 5/ Plants started now usually must receive a certificate of need from the state public utility commission before construction can commence, in addition to satisfying other applicable health and safety regulations.

UNCERTAIN ENVIRONMENT OF THE 1970s

At the beginning of the 1970s, the bright outlook of the preceding two decades continued to dominate the investor-owned utility industry. Anticipating relatively low inflation, moderate interest rates, stable or declining fossil fuel prices, the installation of new and cheaper nuclear plants, and a continuation of modest environmental and safety regulations, utilities expected to double capacity every 10 years. The relationships between most utilities and their regulators--the public utility commissions--also appeared harmonious and optimism prevailed among investors.

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4. See Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* (1980).

5. The term "baseload" refers to the number of hours a plant is relied on to produce power over the course of a year. A baseload plant typically supplies power for that portion of electricity demand that remains stable throughout the day, compared with a "peaking unit" which may be used to meet power demand surges. A baseload plant typically operates over 65 percent of the time. If stoppage for scheduled maintenance is included, a baseload plant can be considered to operate most of the time.

The 1970s marked the start of dramatic changes, however. First, fossil fuel and nonfuel operating and maintenance costs rose dramatically as a result of the 1973-1974 Arab oil embargo and inflation. Utilities passed on these additional costs to industrial and residential customers by charging higher electricity rates. Second, the anticipated growth in electricity demand failed to materialize. As a result, many of the capacity additions planned before 1970 for completion by 1975 were not economically justified. Third, increased regulatory requirements caused construction delays and created new uncertainties for capacity planning. Finally, construction costs for new baseload plants increased beyond utilities' original expectations (especially for nuclear plants) as a result of several factors, including construction delays, high interest rates, changing safety regulations, and construction problems brought about both by utility firms and contractors. Public utility commissions often refused to allow firms to pass on these costs to customers. These adverse conditions led to an unexpected decline in utility earnings and strained the relationship between the utilities and their regulators. By 1980 the industry's average market-to-book ratio--a financial measure used to indicate stock market performance--had fallen to its lowest level in two decades. Investors viewed those utilities with unfinished nuclear power plants with the greatest caution.

Rising Variable Costs

In 1970 the average variable cost of supplying electricity rose for the first time in more than a decade. 6/ Higher oil and gas prices resulting from the 1973-1974 oil embargo and the 1979-1980 oil shortage caused even greater increases in utilities' operating costs. In 1973, for example, electric utility plants paid an average of 87.6 cents, 169.8 cents, and 73.1 cents (in 1984 dollars) per million Btu for coal, heavy oil, and natural gas, respectively. By 1981 the real prices of these fuels had risen twofold for coal, fourfold for oil, and fivefold for gas--to 181.6 cents, 627.6 cents, and 403.8 cents (in 1984 dollars) per million BTU, respectively. 7/

Similarly, nonfuel operations and maintenance (O&M) costs also rose faster than inflation, in part from increased environmental regulation. Between 1970 and 1980, O&M costs for fossil-fuel plants increased from 2.07 mills to 2.55 mills per kilowatt-hour (in 1984 dollars). 8/ These costs

6. Variable costs include fuel and the majority of nonfuel operations and maintenance costs.

7. Department of Energy, Energy Information Administration, *Monthly Energy Review* (September 1985).

8. Department of Energy, Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses in 1980* (1981).

for nuclear plants rose even more, increasing twice as fast as nonfuel costs for fossil-fuel plants for the whole decade, and doubling between 1977 and 1980 alone. 9/

Because utilities could not obtain regulatory approval for price increases quickly enough to keep pace with rising fuel and other O&M costs, their cash-flow positions became strained. For example, as a result of the unexpected rise in fuel costs following the Arab oil embargo, Consolidated Edison Company was forced to skip a cash dividend on common stock in 1974. These cost increases also placed state utility commissions under pressure to grant electricity price increases. Automatic fuel adjustment clauses were established in many states to eliminate the necessity for frequent rate reviews. While this process assured the utilities sufficient cash flow for new fuel purchases, customers quickly felt the effects of the nearly twofold increase in oil and gas prices in 1979 and 1980. (Not all states employed this technique, however. Some states, such as Missouri and Michigan, prohibited their use and 15 other states eventually introduced legislation to restrict such pricing.)

Changes in Growth of Electricity Demand in the 1970s

Over the 40-year the period from 1930 to 1970, the demand for electricity grew at an average annual rate of 7 percent, doubling every 10 years. During the 1960s, falling electricity prices and rising disposable income spurred demand growth. In 1970 these major determinants of demand were expected to continue the 7 percent trend in demand growth. But between 1972 and 1984, electricity prices increased threefold, and real disposable income grew only 2.7 percent per year, compared with 4 percent annually during the 1960s. These unexpected events dampened the increase in electricity demand from the high rates experienced in the 1960s to only 2.5 percent annually over the 1970-1983 period. 10/

At 2.5 percent annual demand growth, capacity requirements would double only every 30 years, rather than every 10 as previously expected. Overforecasting actual demand led to overinvestment in new plants, many of which had to be cancelled. This phenomenon of overforecasting demand was shared by electric utilities throughout the industry and not limited to the small group of utilities that subsequently became financially distressed. But most utilities that cancelled unneeded plants between 1978 and 1983 emerged in relatively good financial shape.

9. Ibid., p. 289.

10. Peak demand, which also shapes supply requirements, rose 3.9 percent over the 1970-1983 period, also below previous expectations.

Increased Regulatory Requirements

Utilities became subject to a host of new regulatory requirements during the 1970s. Plants burning fossil fuels were regulated by the Clean Air Act of 1970 and its amendments in 1977. In 1971 nuclear plants were found to be subject to the requirements of the National Environmental Policy Act for environmental impact statements. 11/ Most states and many localities instituted laws governing power plant sites during the decade. These new requirements tended to increase licensing and construction periods for both nuclear and coal power plants. 12/

The 1979 accident at Three Mile Island (TMI), a nuclear generating station owned by General Public Utilities (GPU), also led to increased regulatory requirements. 13/ Following the incident, the Nuclear Regulatory Commission (NRC) suspended issuance of plant operating and construction licenses for one year. The Kemeny Commission, formed to investigate TMI, criticized NRC's approach to safety, and recommended that NRC require certain changes in equipment and design. The ensuing changes in requirements for quality assurance and safety equipment delayed construction schedules as plants nationwide were "backfitted" to meet these new standards. The TMI incident is reported to have caused construction delays of almost one year and capital cost increases of 2 percent for the typical nuclear plant built in its aftermath. 14/ In addition, 11 states reacted to the TMI accident by passing public referendums designed to limit the development of nuclear power.

Rising Construction Costs

Increased operating costs, lower than foreseen demand growth, and expanded regulatory requirements were only part of the evolving financial crisis in which some utilities found themselves in the 1970s. The other principal factor precipitating the industry's financial difficulties proved to

11. See *Calvert Cliffs v. Atomic Energy Commission*, 449 F.2nd 1109 (D.C. Circuit, 1971).

12. A recent study found regulatory requirements to be an important source of construction delays, along with labor and technical problems and deliberate delays because of reductions in demand growth. See Electric Power Research Institute, *Power Plant Construction Leadtimes* (February 1984).

13. For a thorough description of the events surrounding the near core meltdown at TMI, see Staff Reports of the President's Commission on the Accident at Three Mile Island (Washington, DC: Kemeny Commission, October 1979).

14. See Charles Komanoff, *Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulation, and Economics* (New York: Komanoff Energy Associates, 1981).

be rising construction costs, primarily caused by increases in labor and material costs, higher real interest rates, and longer construction lead times.

Construction costs generally rose most rapidly (relative to overall inflation) for nuclear plants. The cost (in 1984 dollars) of a typical nuclear plant entering commercial operation increased from about $715 per kilowatt (kw) in the 1971-1974 period, to about $1,389 per kw in the 1981-1984 period. The average cost of a plant expected to enter service in 1985 or 1986 has risen to about $2,600 per kw measured in 1984 dollars. 15/ The magnitude of these increases exceeds the level of cost escalation experienced in new coal plant construction (see Table 1).

Much of the growth in the costs of new nuclear power plants can be traced to construction delays and the attendant compounding of carrying charges. The construction period for nuclear utility plants has stretched from six years in the early 1970s to about 10 to 12 years for recently licensed nuclear plants. 16/ Causal factors were labor and equipment problems, plant redesign work necessitated by regulatory changes, and deliberate construction delays because of the waning demand. State regulatory commissions have also found significant utility mismanagement in some construction programs. 17/ The accrual of interest charges because of these delays can be quite large, especially during an inflationary period. For a nuclear plant begun in 1972, with debt financing at 12 percent and labor and materials inflation at 9 percent, the final cost of the plant would be 30 percent higher if the plant were completed in 1984 (12 years from start of construction) than if it were completed in 1980 (eight years from start of construction). Not all utilities incurred significant construction delays, however. A few nuclear plants entering service in the 1979-1983 period were completed in fewer than eight years.

RESPONSES TO CHANGING FINANCIAL PROSPECTS

Between 1974 and 1984, electric utilities cancelled 97 nuclear generating stations and 75 coal plants that were planned for operation in the late 1970s

15. See Department of Energy, Energy Information Administration, *Nuclear Power Plant Construction Activity 1984* (July 1985).

16. See Electric Power Research Institute, *Power Plant Construction Leadtimes* (1984); and Office of Technology Assessment, *Nuclear Power in An Age of Uncertainty* (1984).

17. The New York Public Service Commission, for example, has recently disallowed $1.5 billion of the costs of the Long Island Lighting Company's Shoreham facility because of imprudent management practices.

TABLE 1. ANNUAL RATES OF GROWTH IN COAL AND NUCLEAR CONSTRUCTION COSTS, 1973-1983 (In percents) [a]

Time Period	GNP Price Deflator	Handy-Whitman Construction Index	Coal-Fired Capital Costs	Nuclear Capital Costs
1973-1979	6.4	10.7	18.9	16.5
1979-1983	7.2	6.8	5.9	29.6

SOURCE: Congressional Research Service Report No. 84-236(s), December 31, 1984, based on *Statistical Abstract of the U.S.* (1984); and Department of Energy, Energy Information Administration, *Thermal Electric Plant Construction Cost and Annual Production Expenses (1981)* and *1983 Survey of Nuclear Power Plant Construction Costs.*

a. All growth rates are based on current dollars.

and early 1980s.[18] The Department of Energy (DOE) estimates that the sunk costs for the cancelled nuclear plants amounts to $10 billion.[19] Even with the high number of plant cancellations, reserve capacity margins increased 50 percent during the decade (from 21 percent to 33 percent) because of the completion of many other plants and the decline in demand growth. More cancellations might have occurred, but current regulations appear to have spurred some utilities to complete plants since their costs could only be recovered when the plant became "used and useful."[20] Thus, some utilities preferred to risk the cash-flow problems of construction so that the plant costs would at least be entered into the rate base (see box). Construction postponements--through the "mothballing" of unfinished plants--were also disadvantageous because high borrowing costs continued

18. Edison Electric Institute, *Electric Power Survey* (January 1985).

19. Robert Borlick, *Nuclear Plant Cancellations: Causes, Costs, and Consequences*, Department of Energy, Energy Information Administration (April 1983).

20. "Used and useful," a term used in ratemaking procedures, indicates that a plant is needed and operational. A plant typically must be used and useful before a utility may charge its customers for the investment, unless the regulatory agency specifically allows the utility to charge for construction work in progress.

Utility Ratemaking and the Rate Base

Because utilities are regulated monopolies, the electricity price that they can charge consumers is established by state public utility commissions for intrastate sales and by the Federal Energy Regulatory Commission (FERC) for interstate sales. While FERC ratemaking rules are uniformly applied throughout the country, state ratemaking practices can vary by state, although they tend to conform to certain established guidelines (which are also consistent with FERC practices).

Generally, a state commission holds a quasijudicial hearing to determine a utility's prices. Utility revenues are considered adequate when the prices charged for electricity sales are equal to the cost of providing electricity ("cost of service"), plus some subjective "fair" rate of return on the value of the utility's assets (the rate base). Allowable **service costs** include fuel expenses, operation and maintenenace costs, depreciation of capital stock, administrative expenses, and taxes. An estimate of total expenses for the coming year is typically derived by using an historical "test year," often the most recent 12-month period for which complete financial data is available.

The **rate base** reflects an electric utility's gross capital investment less accumulated depreciation--in essence, the value of the property that is "used and useful" in producing and delivering power. As such, it includes the value of land, buildings, generating stations, and transmission facilities owned by the utility. These assets can be valued by one of three methods: original cost, replacement cost, or--reflecting a compromise between the first two--"fair value." Most states employ fair value accounting. Once the rate base is determined, an allowed rate of return is applied. This rate generally reflects the weighted average rate of return the utility must pay for long-term debt (bonds) and preferred or common stock (equity). Many state commissions require that a plant must be operational to be placed in the rate base. Others may allow a portion or all of the construction work in progress (CWIP) to be included.

during this period and because tax write-offs of losses could only be taken for cancelled plants.

Utilities that quickly cancelled planned projects in the mid-1970s in response to dampening demand generally fared better than those that did not cancel plants until the late 1970s and early 1980s. Firms in the latter category continued to face mounting liquidity problems, since variable costs, as well as dividend and interest payments, increased faster than revenues. Many of these firms are still experiencing liquidity constraints today.

Regulator Response

Many state utility commissions reacted sharply to the building of expensive plants in a time of lower-than-expected demand. In order to shield consumers from large price increases, many commissions did not permit utilities to recover either the carrying or capital costs of plant construction (called construction work in progress, or CWIP) until the plant was fully used and useful. Instead, construction and interest charges were entered in a special account termed Allowance for Funds Used During Construction, or AFUDC. Under AFUDC accounting, the utility did not actually realize a cash return on its investment during construction. Instead, the book value of the account accumulated until the plant was placed into service, at which time the AFUDC account was entered into the rate base and began to earn a return on the utility's investment.

This accounting device had two effects. First, utilities' current cash income declined, as the construction-oriented AFUDC account rose from 12.9 percent of reported income in 1969 to almost 50 percent by 1983. 21/ And second, the size of the AFUDC account often reached several billion dollars by the time the plant was completed. The sudden entry of this amount into the rate base could cause sharp price increases, some ranging from 15 to 70 percent. To counter such price shocks, state regulators began employing "phase-in" plans to lessen the increases of including the entire cost of a new plant into rates all at once. Such measures further delayed utilities' recoveries of their investment costs.

Finally, regulatory commissions began to scrutinize utility plant cancellations more thoroughly. A study of 71 plant cancellations through June 1983 revealed that, in 24 percent of the cases, regulators ruled against any cost recovery. 22/ In 62 percent of the cases, cost recovery was granted for prudently incurred costs and, in the remaining cases, some return on the prudently incurred investment was allowed. Eight state utility commissions, however, ruled against any cost recovery, even if the initial plans for construction appeared prudent. Sunk costs for a number of these plants amounted to millions of dollars.

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21. Edison Electric Institute, *Financial Review-1983: An Annual Report on Investor-Owned Electric Utilities* (July 1983).

22. Ibid, p. x.

Investor Response

Utility investors soon realized that regulatory decisions about the recovery of plant costs could greatly influence a utility's final earnings. If investors viewed a state's regulatory decisions as unfavorable, utilities in that state had to pay higher interest rates to attract capital. Table 2 presents one view of how investors rank state commissions. The rankings range from A, excellent, to E, very poor. In general, state regulators that allowed some or all construction costs to be recovered before a plant was used and useful and allowed a return on equity above 15 percent were most well-regarded by investors.

Irrespective of regulatory climate, utility investors especially penalized nuclear utilities. As nuclear-power costs increased faster than expected in the 1970s, especially after the Three Mile Island accident, investors began to exact a risk premium from utilities seeking to finance nuclear construction. 23/ These effects can be seen clearly in Figure 1.

In 1970, of the utilities rated by Standard and Poor's Corporation, 96 percent of those with nuclear plant construction programs received bond ratings of A or better, thus suggesting a relatively good long-run prognosis for their financial health. (Bonds rated BBB or higher are considered investment grade; those ranked BB and below, speculative). Yet, by 1980, only 67 percent of the utilities with nuclear programs had investment grade ratings. The ratings on some utilities' bonds fell so low by the 1980s that many institutional investors were prohibited by law from buying them, because of their inferior quality. By contrast, investors' views of non-nuclear utilities changed very little during this period. Although the mean bond rating for nuclear utilities had degenerated to BBB by 1983, the mean bond ratings for nonnuclear utilities remained within the AA to A range.

CURRENT CONDITION OF THE INDUSTRY

The investor-owned electric utility industry reached its lowest point financially in 1980. The utilities average market-to-book ratio--a financial measure often used to characterize a firm's anticipated financial performance in the stock market--declined from 2.53 in 1965 to 0.73 in 1980, the lowest level in more than two decades. 24/ Long-term debt for utilities

23. U.S. Department of Energy, *Investor Perceptions of Nuclear Power* (May, 1984).

24. As a ratio of the market price of a utility's stock and the book or resource value per share of stockholder investment, the market-to-book ratio indicates the value investors in financial markets attach to the management and organization of a utility. As the market-to-book ratio declines below 1, the sale of new stock will usually dilute the value of the existing stock.

TABLE 2. EXAMPLE OF INVESTOR RANKING OF STATE REGULATORY COMMISSIONS AND PRACTICES IN 1984

State	Type of Rate Setting	Allowed ROE (In Percents) a/	SBI Rank b/
Alabama	Year-end original cost; no CWIP	15.0	C-
Arizona	Year-end fair value; some CWIP	16.2	C-
Arkansas	Year-end original cost; some CWIP	14.2	C-
California	Average original cost; no CWIP	16.0	B
Colorado	Year-end original cost; some CWIP	14.4	C
Connecticut	Year-end adjusted cost; some CWIP	16.4	B
Delaware	Average original cost; no CWIP	14.9	C+
District of Columbia	Average original cost; some CWIP for pollution control only	c/	D
Florida	Average original cost; some CWIP	15.6	B
Georgia	Year-end original cost; some CWIP	15.5	C-
Hawaii	Year-end original cost; some CWIP	15.0	C-
Idaho	Average or year-end original cost; CWIP in emergencies only	14.9	C-
Illinois	Year-end original cost modified for fair value; some CWIP	15.6	B
Indiana	Year-end fair value; no CWIP	15.8	C+
Iowa	Average original cost; no CWIP	14.7	C-
Kansas	Year-end original cost; CWIP during final year of construction	15.5	C
Kentucky	Year-end original cost; CWIP	15.0	C
Louisiana	Average original cost; some CWIP	c/	E
Maine	Average original cost; no CWIP	16.0	D+
Maryland	Average original cost; some CWIP	14.8	C
Massachusetts	Year-end original cost; no CWIP	16.0	C
Michigan	Average original cost; no CWIP	14.5	D
Minnesota	Average original cost; some CWIP	14.7	C+
Mississippi	Average original cost; no CWIP	15.5	D
Missouri	Year-end original cost; no CWIP	15.6	C-
Montana	Average original cost; no CWIP	14.2	E
Nevada	Year-end original cost; some CWIP	15.0	C
New Hampshire	Average original cost; no CWIP	16.1	C-

(Continued)

TABLE 2. (Continued)

State	Type of Rate Setting	Allowed ROE (In percents) a/	SBI Rank b/
New Jersey	Year-end original cost; some CWIP	15.8	C+
New Mexico	Year-end original cost; some CWIP	15.5	C+
New York	Year-end or average original cost; some CWIP	15.0	C+
North Carolina	Year-end original cost; some CWIP	15.3	C+
North Dakota	Year-end or average original cost;	14.5	C-
Ohio	Average original cost; CWIP when plant is 75 percent complete	16.9	D+
Oklahoma	Year-end original cost; some CWIP	15.0	C+
Oregon	Average original cost; no CWIP	15.8	B
Pennsylvania	Year-end original cost; CWIP only for pollution control	15.5	C-
Rhode Island	Average original cost; no CWIP	14.4	C-
South Carolina	Year-end original cost; some CWIP	14.3	D
South Dakota	Average original cost; no CWIP	14.0	D
Texas	Year-end original cost; some CWIP	16.3	B
Utah	Average original cost; some CWIP	15.0	B
Vermont	Average original cost; some CWIP	16.0	C+
Virginia	Year-end original cost; some CWIP	15.0	C-
Washington	Average original cost; no CWIP	15.8	C
West Virginia	Average original cost; some CWIP	14.5	D
Wisconsin	Average original cost; some CWIP	14.8	B
Wyoming	Year-end original cost; no CWIP	14.8	C-
FERC d/	Year-end original cost; some CWIP	15.5	B

SOURCE: Congressional Budget Office, based on Salomon Brothers, Inc., *Electric Utility Regulation - Semiannual Review* (New York, N.Y.: Salomon Brothers, August 8, 1985).

NOTE: CWIP = Construction work in progress.

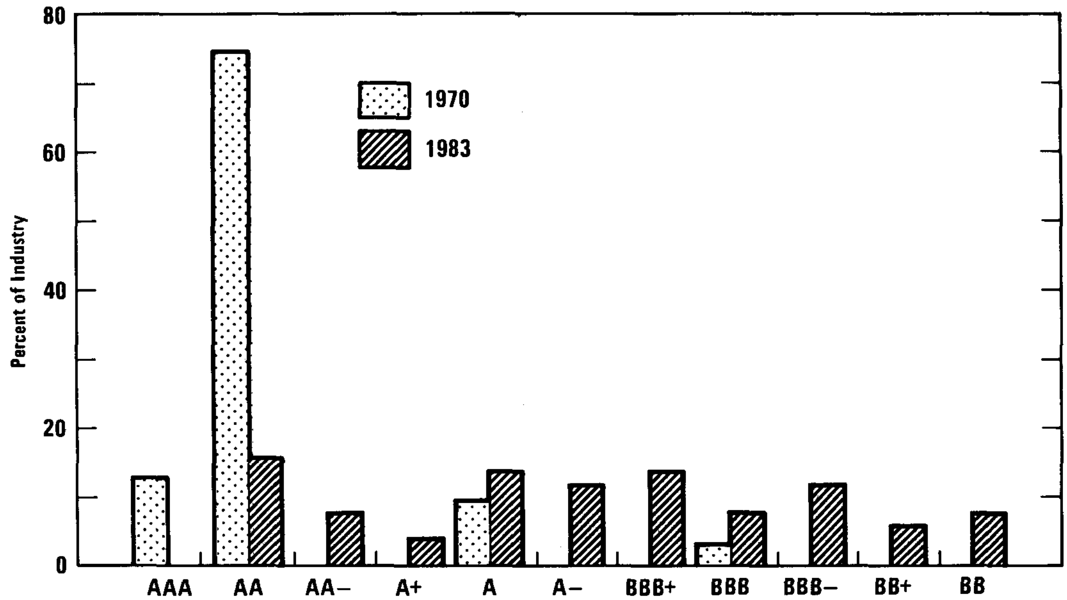
a. ROE is the return on common equity allowed by state commissions in recent decisions on representative major electric utility rates.

b. Ranking is provided by Salomon Brothers, Inc. Regulatory Rank (SBI Rank), with A ranking highest and E lowest.

c. Not available.

d. The Federal Energy Regulatory Commission (FERC) sets rates for electricity that is sold wholesale across state borders.

Figure 1.
Bond Ratings for Nuclear Electric Utilities, 1970 and 1983



SOURCE: Standard and Poor's Bond Rating.

grew from $42.2 billion in 1970 to $124.8 billion in 1982, with interest charges amounting to $11.5 billion alone in 1982. 25/ Utilities' current cash income also declined, as the construction-oriented AFUDC account grew to represent about 50 percent of utility earnings by 1983.

The industry's financial condition has improved markedly in the last five years, however, in part from the economic recovery which has spurred revenues from electricity sales. Industry-wide liquidity, measured by the ratio of cash flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 ratio usually considered a prudent minimum. In addition, the industry's average market-to-book ratio rose to 1.1 in June 1985, up from its 20-year low of 0.73 in 1980. In the course of this overall recovery, the industry has become stratified into two distinct sets of firms, each with particular financial problems. The first group--made up of the financially healthy majority of investor-owned utilities--is experiencing robust growth in earnings. Indeed, about 30 companies will generate 100 percent of their cash needs internally by 1987. For the most part, these firms are not now

25. Mark Luftig and Neal Kurzner, "Electric Utility Regulation--Semi-Annual Review" (New York, NY: Salomon Brothers, Inc., February 26, 1985).

building any baseload plants, but they are concerned that future construction efforts will be plagued by the regulatory and investment problems of the last decade. These firms, therefore, seek measures to reduce investment uncertainties in the long-term. The second group of firms have more immediate problems: they were still engaged in major construction projects in 1983 and 1984 and were experiencing liquidity shortfalls.

Utilities with Liquidity Constraints: 1983-1984

About 15 of the 100 largest investor-owned electric utilities experienced cash-flow shortages in 1983 and 1984 (see Table 3). These firms were identified using a four-fold screening process described in Appendix B. Five of the firms identified (Consumers Power, Long Island Lighting, Public Service of Indiana, Public Service of New Hampshire, and United Illuminating) had market-to-book ratios below 50 percent. Middle South Utilities--a holding company--and Central Maine Power had market-to-book ratios of between 50 and 80 percent. The remaining eight firms (Dayton Power and Light, Toledo Edison, Ohio Edison, Union Electric, Philadelphia Electric, Kansas Gas and Electric, Gulf States Utilities, and Kansas City Power and Light) have shown considerable improvement since they were first identified by the CBO screening procedure and were selling common stock at 80 percent or more of book value by mid-1985.

These 15 utilities have experienced liquidity constraints only in the last several years. In 1974, for example, this group of firms exhibited no liquidity problems, having a cash-flow coverage to dividends ratio of 2.5, relative to the industry average of 2.6. (A cash-flow coverage ratio is defined as income available to common equity plus noncash expenses less noncash credits divided by dividends paid.) A high cash-flow coverage ratio (above 2) indicates the firm has adequate liquidity; as the ratio falls below 2, however, liquidity problems arise. Cash-flow coverage ratios for this group of firms eroded to 1.5 during 1984, compared with an industry average of 2.7.

Although specific causes vary by firm, construction programs have probably been the most important overall reason for the liquidity problems of these firms. Like most investor-owned utilities, these firms were considered excellent long-term bond risks in 1974, rated A or higher. With long construction delays and the erosion of regulatory and/or investor support, bond ratings dropped and capital costs increased. Public Service of New Hampshire, for example, with a rating of BBB, was forced to raise approximately $450 million in bonds with effective interest rates ranging from 19 to 21 percent in order to continue building its still unfinished Seabrook

TABLE 3. ELECTRIC UTILITIES WITH LIQUIDITY CONSTRAINTS IN 1983 AND 1984 a/

Firm	Plant	Location of Service Area
Central Maine	Seabrook 1 Millstone 3	Maine
Consumers Power	b/	Michigan
Dayton Power & Light	c/	Ohio
Gulf States Utilities	River Bend 1	Louisiana, Texas
Kansas City Power & Light	Wolf Creek	Kansas, Missouri
Kansas Gas & Electric	Wolf Creek	Kansas
Long Island Lighting	Shoreham	New York
Middle South Utilities	Grand Gulf 1 Waterford 3	Louisiana, Arkansas, Mississippi
Ohio Edison	Perry 1 Beaver Valley 2	Ohio
Philadelphia Electric	Limerick 1	Pennsylvania
Public Service of Indiana	b/	Indiana
Public Service of New Hampshire	Seabrook 1 Millstone 3	New Hampshire, Maine, Vermont
Toledo Edison	Perry 1 Beaver Valley 2	Ohio
Union Electric	Callaway 1	Illinois, Iowa, Missouri
United Illuminating	Seabrook 1 Millstone 3	Connecticut

SOURCE: Congressional Budget Office.

a. These utilities were identified by comparing a series of standard financial ratios over the 1983-1984 period as described in Appendix B. These historical ratios do not necessarily imply similar circumstances today.

b. Plant deferred or abandoned.

c. Plant being converted to a coal-fired facility.

plant. By comparison, bond offerings by A-rated firms were sold for 12.9 percent during 1984. 26/

As construction programs are completed, remaining liquidity problems should begin to ease. If they do not, the troubled utilities may face more difficult choices. (Other options to resolve the cash-flow difficulties for this group of firms are discussed in Chapter III. The long-term issues confronting the industry are presented in Chapter IV.)

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26. Mark Luftig and Neal Kurzner, "Electric Utility Regulation--Semi-Annual Review," Salomon Brothers, February 26, 1985.