The original documents are located in Box 7, folder: "National Energy Outlook - 1976" of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Chapter V

ELECTRIC UTILITIES

INTRODUCTION

During most of the period since World War II, electricity consumption grew at 7 percent while prices declined steadily. Consumption and price trends have since broken with historical patterns: electricity prices have risen precipitously and demand growth is uncertain. There has been talk of possible power shortages even though current reserve margins far exceed the recommended level, and capacity is still expanding. Analysts continue to disagree over the financial viability of the industry, and regulators face the conflicting demands of strengthening utilities and holding prices down.

The Significance of Electricity

Electricity has come into prominence in large part because of its versatility. It is usable energy that can be produced from coal, oil, gas, uranium and renewable geothermal and solar sources; and it can be used for a wide range of purposes in residences, commercial establishments, and industry. This versatility, however, is expensive both in economic terms and in energy consumed. Electric power requires large amounts of capital for generating and distribution equipment, and uses about three Btu of energy input to produce one equivalent Btu of electricity output. In 1974, electric utilities required about 27 percent of total energy ultimately consumed. The use of electricity itself is essentially pollution free, but its generating stations often concentrate pollutants in a localized, single, and highly visible source.

The 1973 oil embargo and subsequent price increases, coupled with the coal strike in 1974 led to large fuel cost increases for many of the Nation's utilities. Consumer reaction to price increases, a heightened awareness of energy conservation potential, and the economic slowdown combined to bring about the first hiatus in the growth of electricity consumption in more than a generation. The uncertainty that resulted, along with the stress in U.S. financial markets during 1974 led to major cutbacks in the development plans for future generating capacity. Determining what share of the cutbacks was due to financial, technical siting and licensing problems, or to reduced demand forecasts has become a widely debated issue.

THE EVOLUTION OF UTILITY PROBLEMS

For decades, the electric utility industry was known for its stability. Demand was predictable, growth was deemed inevitable, and earnings increased year by year. As a result, utility securities were considered to be among the safest available investments. It was normal practice to hold 10 to 20 percent of any large common stock portfolio in utility equities, and utility bonds carried an interest rate that was about equal to that of the equivalent industrial bonds; (they are now .60 percent higher). There was consequently little impediment to financing new construction.

The post-World War II period was characterized by rapid technological advances in the design efficiency of generating and transmission equipment. As companies expanded generation capacity, each new plant was larger and more efficient, resulting in steadily declining costs per unit of output.

Public utility commissions set consumer rates based on historical costs to the utility with the expectation that these rates would yield a target (allowable) rate of return on capital. Since costs were declining, utilities typically earned more than the allowable rate of return. Consumers were not concerned, however, since rates were also decreasing, despite the lag time experienced before cost decreases were passed on.

The same lag turned against the companies, however when costs stopped declining in the late 1960's and began to rise. This fundamental reversal of previous cost trends was exceedingly complex both in its genesis and its impacts, and lies at the root of present utility problems.

Plant Cost Increases

While there are many reasons for the reversal in utility cost trends, the most important is the dramatic increase in the cost of electrical generating plants, particularly since the carrying cost of fixed assets represents about 50 percent of utility costs in each year.

The decisions to invest in plant are made with long planning lead times. Utilities now generally file ten-year capacity projections with the National Electric Reliability Council. The lead time for planning construction of the large base load electric generating plant has increased to ten years so that decisions must be made well in advance.

Most of the money is spent during the five years before a base load plant goes into service. However, consumers do not normally begin to pay for the cost of such plants until after the plants have come on line. The normal practice in the industry requires companies to accumulate the cost of acquiring the needed capital and to add it to the cost of the plant. Rate payers are not required to make any payments for such costs until the new plant goes into service and is included in the rate base. At that time, rates are increased to cover the return on the newly evaluated rate base. Because there are no revenues paid in on the new plant until it goes into service, a non-cash credit, Allowance for Funds Used During Construction (AFDC) is made to income during the construction years. This credit in 1974 averaged 31 percent of reported income, but contributed nothing to supplying cash for construction.

While construction, labor, and materials costs have increased substantially since the late 1960's, a significant percentage of the total plant cost increase is due to increasing environmental and safety related requirements. The major environmental or safety changes for nuclear reactors involve more complex cooling systems to prevent damage to local aquatic life, and systems to assure minimal release of radioactivity. The major environmental requirements for coal-fired plants primarily involve flue gas desulfurization (scrubbers), precipitators to remove fly ash, and additional water cooling requirements.

The Atomic Energy Commission made a series of four studies of generating plant costs covering plants started in 1967, 1971, and 1973. These studies show that the direct and indirect construction costs of large base load plants, both coal and nuclear, tripled during the period. The actual total cost of the delivered plant is further escalated above the amounts of direct and indirect construction costs by an increase in the total project duration from five years for plants started in 1967 to nine years for a plant started in mid-1974. This increase in construction lead time has led to a substantial increase in cost escalation and in the total accumulation of interest charged during the construction period. The net result is that the full cost of the delivered generating plant has risen by a factor of five over the period (see Figure V-1).

The data here relate largely to plants due to be delivered in future years. The cost per kilowatt of capacity in constant dollars declined steadily until about 1970. At that point, costs turned upward and have since continued to accelerate (see Figure V-2).

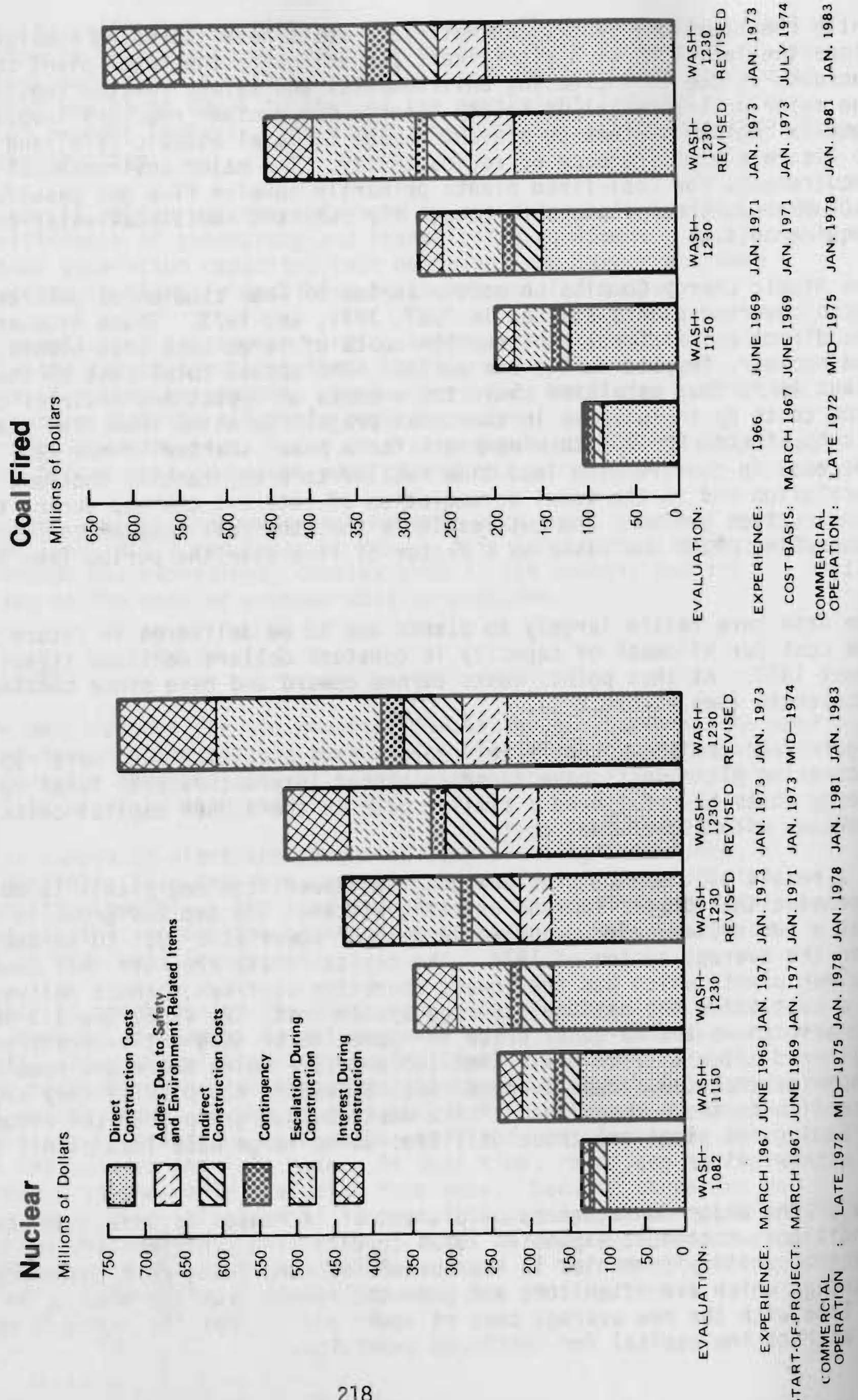
Figure V-2 also shows that fixed charges have escalated even more rapidly as increasing plant costs have added to higher interest rates. Total busbar energy costs have followed a similar path as the higher capital costs have combined with higher fuel costs.

As a result of these complex changes, the power from new plants is more expensive than power from the existing system. The gap has grown to the point that a new system ordered now would deliver power at a cost 20 percent higher than the average system of 1974. The capital costs are such that even a nuclear plant, which has the lowest operating cost/kWh, cannot deliver power at a cost below the national average system cost. By 1985, the $13 Reference Scenario shows the marginal price for power to be 34.4 mills versus an average delivered price of 29.7 mills (see Table V-1). While there are some individual companies that can reduce average costs by adding new plants, they are the exception to the current trend. The most obvious group that can reduce costs by adding new plant are those utilities using large base load plants fired by either oil or gas.

One of the major consequences of plant cost increases is that under current conditions, continued expansion leads to declining profitability for the electric utility companies in the absence of continuous rate increases. Hearings which are often long and extended result from the need to bring rates in line with the new average cost of power and to meet the payments required to attract the capital for continued expansion.

Figure V-1

Comparison of Plant Cost Estimates
(Total Investment for 1000 MWe Plants)

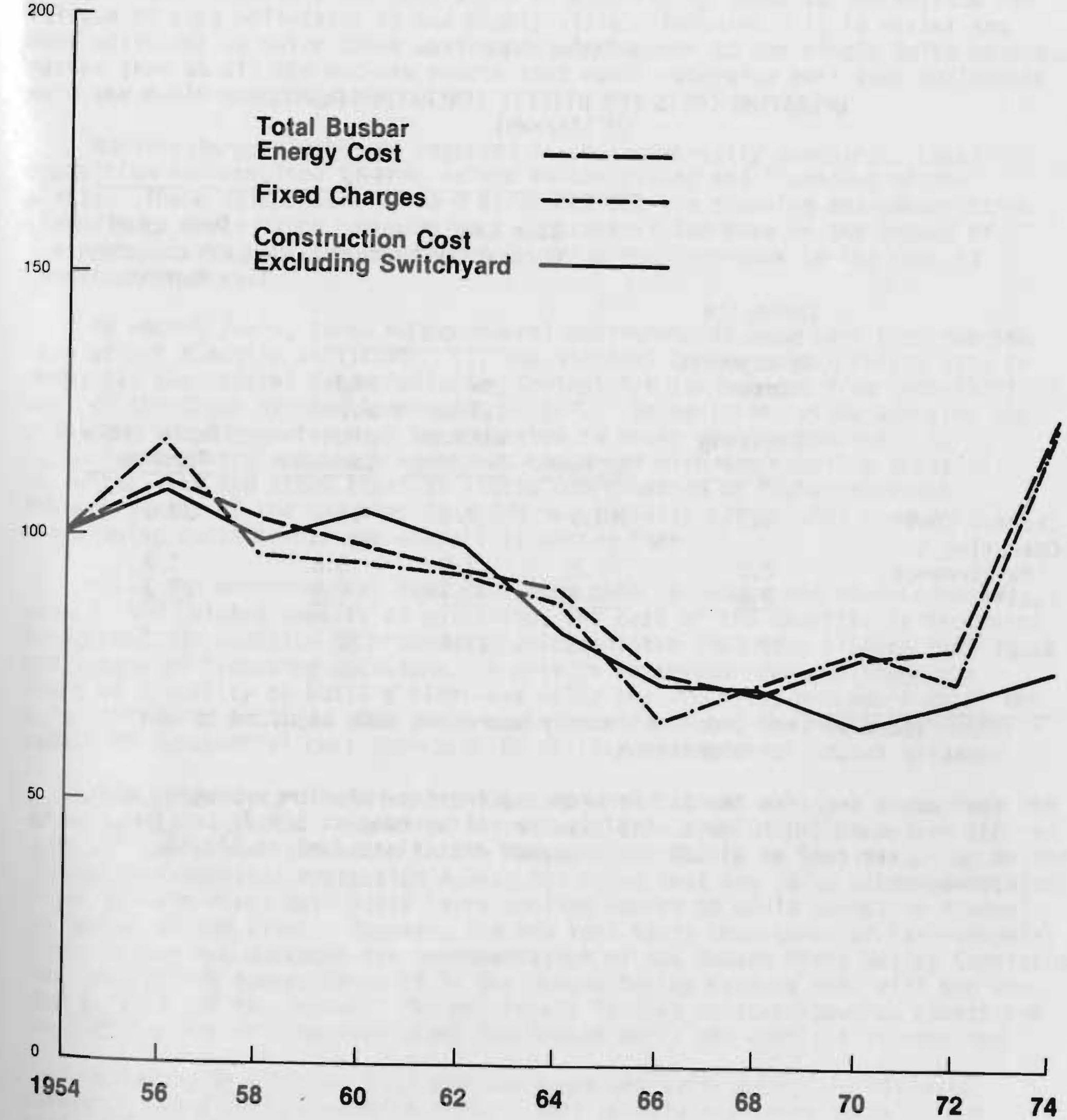


Source: U.S. Atomic Energy Commission.

Figure V-2

Key Factors of Power Cost Rise

(Indexed to 1954 = 100 and Adjusted for Inflation)



Source: Electrical World Cost Surveys.

Table V-1

OPERATING COSTS FOR UTILITY GENERATING PLANTS
(Mills/kWh)

	Composite System (.48 capacity factor)	1985 Base Load Plant (.70 capacity factor)			1985 Peak Load (.08 capacity factor)
			Coal		
	Existing 1974*	Nuclear	Low Sulfur without Scrubber	High Sulfur with Scrubber	Simple Cycle Turbine
Capital Costs	6.2	13.5	9.3	11.7	30.0
Operating & Maintenance	2.0	1.8	2.0	3.5	3.0
Fuel**	9.0	3.0	10.1	6.9	28.7
Total	17.2	18.3	21.4	22.1	61.7

* 1974 figure derived from preliminary operating data adjusted to .48 capacity factor for comparison.

** Fuel costs are from the $13 Reference Scenario: Uranium averaging $13 per pound (with SWU's at $75), low sulfur coal at $24.73 per ton; high sulfur coal at $15.96 per ton; and distillate fuel at $13.90 per barrel.

Licensing and Siting Delays

The problem that increasing plant costs present to utilities has been complicated by difficulties in receiving licenses to build large new generating plants. Electricity is by far the least environmentally damaging source of energy as used by the ultimate consumer. It is not burned in the home or the factory, and therefore does not release oxides of sulfur or nitrogen, or particulates. However, the generation of electricity tends to concentrate the release of such pollutants in one highly visible location. It is easier and more efficient to solve these environmental problems at the single point source, rather than at all the end-use points that would otherwise emit such pollutants were the fuels used directly.

However, large plants are regarded as environmentally damaging. Local opposition has resulted in long delays in the siting and licensing of new plants. These delays have in turn stretched out the planning and construction expenditure cycle which has led to a substantial increase in the amount of interest costs during the construction period and increases in the cost of construction itself.

In recent years, three major Federal environmental laws have been enacted that affect electric utilities: (1) the National Environmental Policy Act, in 1969; (2) the Federal Water Pollution Control Act (as amended from 1965-1972); and (3) the Clean Air Act Amendments in 1970. In addition, state agencies and even some local agencies have been created to cover similar domains. In licensing a powerplant, each agency is concerned with its specific areas of responsibility and often there is little coordination of these processes. Moreover, many of the agencies function sequentially rather than concurrently, lengthening considerably the overall licensing time.

While the environmental laws have done much to reduce the adverse health effects and related impacts of pollution, the cost of the benefits is beginning to appear. In addition to procedural delays, these laws have allowed individual challenges of licensing decisions. A private intervenor can challenge the right of a utility to build a plant and delay the licensing procedure until the suit is finally settled. For large-scale modern plants, the resulting delays result in substantial cost increases to utility consumers.

Other conflicts involving overlapping jurisdictions can lead to extreme and often unusual results. One which illustrates the kinds of problems that can result is the current situation in the Hudson River Valley in New York. The United States Environmental Protection Agency has ruled that any large steam power plant sited on this river must build large cooling towers to avoid excessive thermal pollution of the river. However, the New York State Department of Environmental Conservation has accepted the recommendation of the Hudson River Valley Commission that no cooling towers be built in the Hudson Valley because they will mar the scenic value of the region. The net result is that no steam-powered plants can be licensed for construction along the Hudson until the conflict is resolved.

Particularly controversial are the questions surrounding the ultimate safety of the nuclear operating cycle. This uncertainty tends to delay the siting of any nuclear plant through extended hearings, suits and arguments. It has also compelled close scrutiny of safety requirements which has in the past led to instances where plans have been revised during construction as new requirements are levied. Such revisions increase construction costs, sometimes substantially, both directly and indirectly through delay of the construction process and the resulting financial charges accumulated during the period of construction.

Capacity Utilization

While rapid increases in both fixed and operating costs were occurring, another more subtle change in the electric utility industry was leading to reduced economic efficiency and additional price increases. To the extent that plant available for use (after allowing for a reserve margin) is fully utilized, production costs are minimized. Conversely, to the extent that the plant is underutilized, production costs increase. The capital intensiveness of the electric utility industry tends to amplify any swings in the degree to which plant is utilized in either direction. Such a swing is inevitable whether or not the cost of incremental plant is increasing, but was clearly less of a problem when incremental plant costs were decreasing.

Another factor that has led to a short-run increase in costs per kilowatt-hour is the current excess reserve position of the industry amounting to nearly 14 percentage points above the normal reserve margin of 20 percent. More than half of the annual cost of operating a utility is fixed, regardless of the number of kilowatt-hours sold. As more capacity comes on line, these fixed costs increase. Since 1973, substantial amounts of new capacity have been added while demand has been flat or only slightly up. As a consequence, there have been increased overhead costs per kilowatt-hour. These unit cost increases will decline when demand rises enough to bring reserve levels back to normal.

One of the most significant long run factors in capacity utilization is the relationship between peak load and average load. In an individual system, peak is measured as the daily coincident peak - the time period during which the maximum coincident power demand reaches the system - with the highest daily peak during a calendar year being the annual peak. The absolute peak for the year in recent years for most of the Nation's utilities has occurred in the summer, in the late afternoon. The national aggregation of these summer peak loads is measured as the sum of the maximum loads of each individual system during the summer months, whether or not they fall on the same day. This aggregated number is important in assessing reserve margins and system reliability, although system-specific analysis is required for a definitive assessment.

Peak demand for power (kilowatts of capacity) has been growing faster than overall demand for electrical energy (kilowatt-hours) which leads to a steady deterioration in load factor (see Table V-2). Such a trend ultimately impacts significantly on the retail price for electricity as more plants remain idle for significant portions of the year. This underutilization must also be considered in any analysis of capacity requirements, since deteriorating load and capacity factors are the direct result of excessively uneven demand patterns.

Table V-2

HISTORICAL GROWTH: PEAK LOAD AND TOTAL ELECTRIC DEMAND

Year	Load Factor	Non-Coincident Summer Peak Load: Thousand Megawatts	Non-Coincident Summer Peak Load: Percent Increase	Delivered -- Total Electric Utility Industry: Billion kWh	Delivered -- Total Electric Utility Industry: Percent Increase
1960	65.5	132.8	5.99	683.2	9.02
1961	64.8	141.0	6.17	720.7	5.49
1962	64.9	149.1	5.71	776.1	7.69
1963	65.2	159.5	6.98	830.8	7.05
1964	64.2	175.0	9.75	890.4	7.17
1965	65.0	186.3	6.46	953.4	7.08
1966	64.7	203.4	9.15	1,039.0	8.98
1967	65.3	213.5	4.97	1,107.0	6.54
1968	63.5	238.0	11.50	1,202.3	8.61
1969	64.1	257.7	8.26	1,307.2	8.72
1970	63.9	274.7	6.60	1,391.4	6.44
1971	63.2	292.1	6.35	1,466.4	5.39
1972	62.5	319.2	9.26	1,577.7	7.59
1973	62.0	343.9	7.75	1,703.2	7.95
1974	61.2	349.3	1.56	1,700.8	(0.14)
1975	61.0E	356.2	2.00	1,734.0E	2.00E

E = estimated

Compounded growth rate for the period:	7.6	7.2
Compounded growth rate, 1970-1974:	6.7	5.7

Source: Edison Electric Institute

The bunching of demand peaks during the day is directly related to consumer behavior, which is influenced by the rate structure proposed by utilities and approved by regulatory commissions. To some extent, the variability of these consumer patterns has been exacerbated by recent unfocused conservation efforts. While overall demand has been conserved, there has been less effort, so far, to discourage large groups of consumers from making coincident increases in load which lead to large system peaks, e.g. high individual demand for air conditioning on the hottest afternoon of the summer. System peaks can be offset to some extent by power drawn from neighboring systems not concurrently experiencing peak demand. Power pooling systematically achieves the exchange of such power, but is limited by the fact that rarely are time or climatic differences great enough within a pool to offset peaks. The load management techniques discussed later in the chapter seek to reduce this problem.

Fuel Cost Increases

In addition to the higher cost of new generating plants, there have been substantial increases in the cost of fuel to electric utilities.

The Clean Air Act Amendments of 1970 have led to a major shift in utility fuel mix. A number of existing coal plants were switched to low sulfur oil in order to meet ambient air standards. This shift in fuel mix brought with it a major increase in the operating cost of the utilities. In 1950, this figure had actually decreased to only 2.9 mills per kWh and another decade later had risen only to 3.4 mills. By 1973, average fuel costs increased to about 4.9 mills per kWh, an increase of 44 percent in only three years. By 1974, following the oil embargo and the coal strike which increased fuel costs, this average increased to 9.3 mills, a jump of almost 100 percent in a single year.

Fuel costs amounted to roughly 20 percent of the retail price of electricity in the early 1970's but the rapid and frequent increases raised this figure to 35 percent in 1974. For the investor-owned companies subject to rate regulation, the normal historical cost-based regulatory procedure would have been inadequate to cope with such rapid change were it not for the widespread practice of automatic adjustments for fuel cost changes that could be passed through without prior formal review. Of the $7.4 billion in revenue increases to the industry in 1974, $5.3 billion was needed to cover added fuel costs.

Rate Increases and Demand Effects

The accelerating pressures on the industry have led to a massive increase in the number of rate applications generally unrelated to fuel costs. As a consequence, the load on regulatory agencies has increased substantially. During 1975, utility commissions granted rate increases amounting to more than $3 billion. Nevertheless, at the end of the year, requests amounting to more than $4 billion were still awaiting commission action (see Table V-3).

Table V-3

BACKLOG OF ELECTRIC UTILITY RATE CASES

Quarter Ending	Total Dollar Value of Increases Granted ($ Millions)	Number of Cases Pending	Total Dollar Value of Increases Pending ($ Millions)
3/31/70	73	45	512
6/30/70	80	46	615
9/30/70	217	47	435
12/31/70	164	59	679
3/31/71	177	71	939
6/30/71	302	86	986
9/30/71	114	105	1,237
12/31/71	232	99	1,157
3/31/72	304	96	938
6/30/72	191	104	1,967
9/30/72	107	102	1,317
12/31/72	268	99	1,123
3/31/73	146	96	1,059
6/30/73	144	123	1,572
9/30/73	419	112	1,283
12/31/73	375	137	1,656
3/31/74	526	144	2,052
6/30/74	497	172	2,769
9/30/74	524	164	3,068
12/31/74	655	183	4,015
3/31/75	1,088	183	4,023
6/30/75	719	181	4,267
9/30/75	600	189	4,283
12/31/75	688	185	4,073

Source: Edison Electric Institute

During 1974, revenues of the investor-owned utilities rose by $7.4 billion, which represents 27 percent of 1973 revenues of $27.5 billion. The increase in fuel costs of 1974 amounted to $5.3 billion, or more than 70 percent of the operating expense increases for the year. Kilowatt-hour sales for the year were substantially unchanged from those of the previous year, and there were large rate increases to consumers, about three quarters of which were accounted for by the pass-through of the fuel cost increases. The other quarter represented rate increases granted following rate hearings. These were felt on the East and West Coasts where significant quantities of residual fuel oil are used (see Table V-4).

Table V-4

PRICE INCREASES AND DEMAND CHANGES: 1973-1974

Census Regions	Percent Price Change	Percent Demand Change
New England	38.7	(2.2)
Mid-Atlantic	37.1	(2.5)
South Atlantic	30.1	(0.4)
East North Central	18.2	(0.8)
East South Central	18.7	0.2
West North Central	8.7	0.7
West South Central	15.7	2.6
Mountain	9.4	5.8
Pacific	23.1	(0.8)
(Weighted) Average	23.8	(0.1)

In the regions most directly affected by the fuel cost increases, electricity costs to the residential consumer have, in some cases, doubled. There are a number of cases in which the electric bills for an electrically-heated home are larger than the monthly mortgage payments. The result has been increased pressure on rate commissions to make careful and lengthy investigations of utility requests for rate relief. The increased opposition to costly new plant investments has increased delays in siting and licensing. These delays, in turn, tend to raise costs both to the utilities, and, in the long run, to the consumers.

In those regions with large and sudden price increases, there have generally been substantial reductions in demand. Recent FEA economic studies indicate that the demand elasticity for electricity is such that large price increases can be expected to cut into future demand despite large increases in the prices of other energy sources. One of the critical questions facing this industry is whether there has been a significant permanent change in customer behavior that will lead to continued lower growth in the future. FEA estimates for the next ten years indicate that electricity demand will grow at a rate lower than the historic seven percent. However, the projected 5.4 percent growth rate still means that electricity will continue to grow about twice as fast as overall energy demand.

The year following the embargo showed large changes in the pattern in demand growth for power by all sectors. Nonetheless, both the large light and power (largely industrial) and the residential sectors continued to grow that year, although at very low levels. The small light and power sector (largely commercial), on the other hand, registered negative growth in 1974 but subsequently revived in 1975. The residential sector has also grown in 1975, but without reaching previous rates of increase. Large light and power, which declined significantly in 1975, has been historically sensitive to economic and price fluctuations, and appears to be reacting to the recent economic slowdown. A rapid recovery would be reflected in industrial production which could induce abnormally high increases in demand for industrial power during the first two or three years of recovery as occurred in 1972 and 1973 (see Table V-5).

Table V-5

PERCENT INCREASE (DECREASE) IN DEMAND FOR ELECTRICITY BY CONSUMING SECTOR

	1964-69	1970	1971	1972	1973	1974	1975
Residential	9.3	9.8	7.0	6.8	8.4	0.1	6.2
Small Light & Power	9.3	9.1	6.7	8.4	9.7	(1.1)	7.0
Large Light & Power	6.4	2.8	3.5	7.9	7.5	0.3	(4.7)
Total Consumption	8.0	6.4	5.4	7.6	8.0	(0.1)	2.0

Source: Edison Electric Institute (derived)

The uncertainties of future demand patterns have two significant effects on utility costs. The first effect is the possible deferral of construction decisions which may increase the cost of those plants eventually built.

The second effect is an increase in the cost of capital to the utilities. The investing public requires an incremental return on investment that is directly related to the extent to which the economic future of the investment is uncertain. Electric utilities used to be among the most certain of the available private sector investments; this is no longer true.

The Utility Financial Situation

The electric utility industry, as the Nation's most capital intensive industry, has very large capital requirements to meet its service demand. Because of its high investment needs and low amortization rates capital investment of almost $4 is needed to produce $1 of annual revenues (sales). By contrast, the average manufacturing company needs only $.75 to produce a dollar of annual sales. Even the more capital intensive industrial groups need considerably less capital to generate a dollar of sales: telephone companies need about $2.75; aluminum companies need $1.30 on average and petroleum companies need only about $1.

As a result of this capital intensiveness, the fixed charges paid to finance the required investment play an important part in determining the ultimate price electric utilities must charge for their product. Other fixed charges such as depreciation, insurance, and property taxes also weigh heavily in the total cost of delivered electricity.

A further result of capital intensiveness is that electric utilities must finance a large part of their growth through the continuous sale of additional securities. The return on common equity that a utility must earn to finance its growth depends on the equity's yield and upon investors' estimates of the growth rate of dividends per share. This growth rate in turn depends on the fraction of earnings not paid out to investors, the actual return on equity, and proceeds from the sale of additional equity.

In the face of continuing needs for external financing, utilities must earn a return on equity that is at least sufficient to keep the price of common stock at book value. If they do not, continued sales of common stock will reduce per share earnings and make it impossible to raise adequate funds. The market evaluation of the return that is needed varies as the supply of savings shrinks or expands relative to the demand for investment. A fuller discussion of these financial issues is provided in Appendix B of this chapter. The key finding of that analysis, however, is shown below (see Table V-6). The table shows the minimum earning that could be expected to provide a market value to book value ratio of one. Earnings have been low for several years, but it was not until the early seventies that the shortfall became very large.

Table V-6

REQUIRED AFTER TAX RETURNS VS. ACTUAL RETURNS
($ Millions)

Year	Required Returns to Capital	Actual Returns Capital	Actual minus Required	Percent Difference
1974	$11,092	$9,755	(1,337)	(12.1)
1973	9,027	8,493	(535)	(5.9)
1972	8,027	7,404	(623)	(7.8)
1971	6,614	6,424	(190)	(2.9)
1970	6,268	5,603	(665)	(10.6)
1969	5,140	4,953	(187)	(3.6)
1968	4,455	4,454	(1)	--
1967	3,992	4,137	145	3.6
1966	3,566	3,821	254	7.1

Source: Edison Electric Institute

Until 1974, a rate increase of less than 4 percent would have proved sufficient to cover the earnings shortfall assuming that about 40 percent of a rate increase could be expected to go for income taxes. In 1974, the shortfall widened appreciably--and it would now take a rate increase in excess of $2 billion to restore after tax earnings.

The stock market has reflected this relationship in the evaluation of electric utility equities. In 1966, when actual returns had been exceeding required returns for a long period, market value averaged 2.05 times book value for the stocks. This ratio declined through 1974 and reached its nadir in the wake of the announcement by Con Edison that it would pass its dividend. The market dropped to an average of .67 times book value. Subsequently, the market recovered as the 1974 energy crisis atmosphere passed; interest rates declined and utility earnings rose slightly. By June, 1975 the average market to book ratio had risen to .89 but was still well below 1.0 (see Figure V-3). The ratio must rise at least slightly above one if the companies are to be able to continue to raise the amounts of equity needed in coming years.

The return on average common equity for electric utilities decreased modestly from 12.7 percent in 1966 to 10.6 percent in 1974, as is shown in Table V-7. However, the quality of electric utility earnings has deteriorated sharply. This is due to the increase in the portion of total earnings represented by non-cash income. The most important of such items is the Allowance for Funds Used During Construction (AFDC), which is credited to income and added to plant costs and which provides no cash for operations, but only reflects the cost of capital required for ongoing construction projects. AFDC represented about 4 percent of net income in 1965. In 1974, however, this non-cash item accounted for 31 percent of utility earnings (see Table V-7).

Table V-7

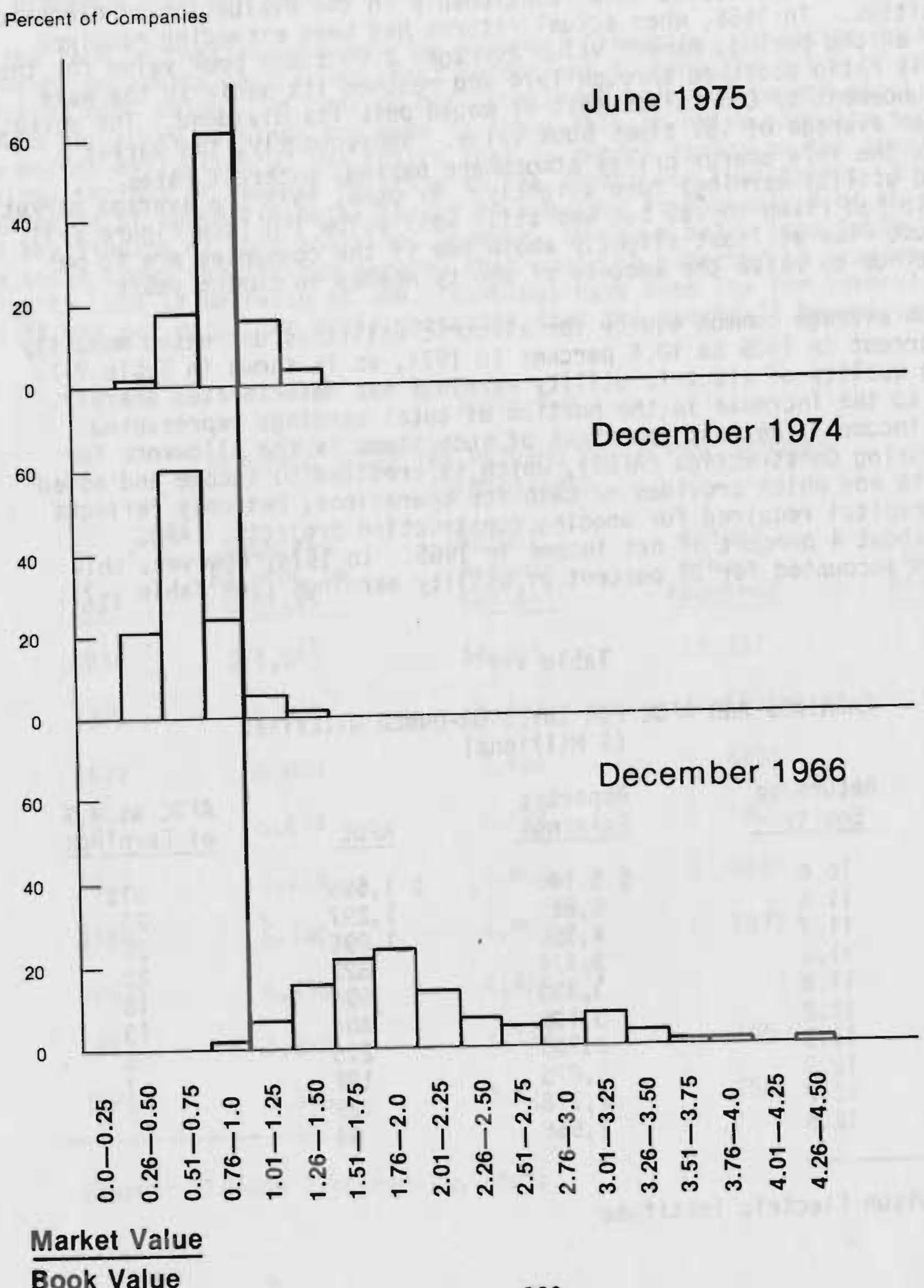
EARNINGS AND AFDC FOR INVESTOR-OWNED UTILITIES
($ Millions)

Year	Return on Equity	Reported Earnings	AFDC	AFDC as a % of Earnings
1974	10.6	$ 5,146	$ 1,596	31%
1973	11.5	4,851	1,297	27
1972	11.7	4,356	1,095	25
1971	11.6	3,774	822	22
1970	11.8	3,333	594	18
1969	12.2	3,130	405	13
1968	12.3	2,960	275	9
1967	12.7	2,875	189	7
1966	12.7	2,718	129	5
1965	12.5	2,556	94	4

Source: Edison Electric Institute

Figure V-3

Ratio Of Market Value To Book Value Of Electric Utility Stock



The reduction in cash earnings has severely affected the financial stability of electric utilities which cannot use such reported earnings to pay dividends or to meet their debt obligations.

In order to finance their capital needs, utilities have therefore been forced to rely increasingly on external funds. The sale of debt by utilities is now severely limited by the decline in interest coverage ratios--generally the ratio of income before interest and income taxes to pro forma interest payments. In most states this legal limit is 2:1 which many utilities have reached or are rapidly approaching. In 1966, the average coverage ratio was as high as 5.3. Yet, by 1970 it had declined to 3.4:1 and by 1974 to 2.1:1. Thus, many utilities are barred from acquiring additional capital through the issuance of debt.

As the cost of utility plant has increased, utility construction expenditures have had to grow even more rapidly. The past growth rate of the industry dictated a doubling of capacity every decade; construction expenditures, however, quadrupled in the nine years from 1965 to 1974.

With a dramatically increased need to raise external funds for new plant, long-term financing by electric utilities increased over eight times from 1965 - 1975 to meet investment requirements. Since revenues represent only 30 percent of net utility plant, and since current new investment now approximates 10 percent of total assets, annual construction expenditures amount to more than 35 percent of total revenues. It is clear that the industry cannot finance any substantial portion of such expenditures from retained earnings. In fact, the ratio of total investment financed externally increased from 45 percent in 1965 to 92 percent in 1974. During 1975, financial conditions within the industry improved, bringing external financing down to 82 percent (see Table V-8).

This increasing reliance on the financial markets, coupled with the continuing trend of rising plant costs may make it difficult for utilities to raise the necessary capital without continued improvement in both the industry and the financial markets. The potential financing problems facing the electric utility industry are discussed in more detail in Chapter VI of this report.

Table V-8

ELECTRIC UTILITY CONSTRUCTION EXPENDITURES AND LONG-TERM FINANCING
($ Millions)

Year	Construction Expenditures	Long-Term Financing	Short-Term Financing	Percent Investment Financed Externally
1975	$ 15,200E	$ 13,197	$ (700)*	82%E
1974	16,350	12,188	2,770	92%
1973	14,907	9,264	1,174	70%
1972	13,389	8,716	380	68%
1971	11,894	9,368	137	79%
1970	10,145	8,232	(138)	80%
1969	8,294	4,875	781	68%
1968	7,140	3,833	1,602	76%
1967	6,120	3,329	265	58%
1966	4,932	2,773	158	59%
1965	4,027	1,641	150	45%

* Estimated

Source: Edison Electric Institute

EXPANSION REQUIREMENTS

The combination of demand uncertainty, siting and licensing delays, financial difficulties and reversal in the economics of generation costs has made continued rapid expansion of generating capacity both more difficult and less desirable for the utility companies. Without immediate rate adjustments, profits now tend to fall as new plants are brought on line. In addition, there are increasing impediments to the siting and licensing of new plants, coupled with large uncertainties concerning the eventual cost of the plants.

Deferrals and Cancellations

One of the first and most visible effects of the uncertainties was the cancellation or deferral of plant additions. When the rate of growth in demand for electricity fell in 1974, utilities reassessed their construction programs on the basis of expected needs and their financial capability. The cutbacks and deferrals announced at the time represent 140,600 megawatts or 67.5 percent of planned nuclear capacity additions and about 74,500 megawatts or 30 percent of planned coal-fired plants (see Figure V-4).

A task force created in FEA reviewed the full range of issues involved in these announced cancellations and deferrals. It was clear from individual utility company responses while certain of these were widespread others were particular to companies or regulatory jurisdictions.

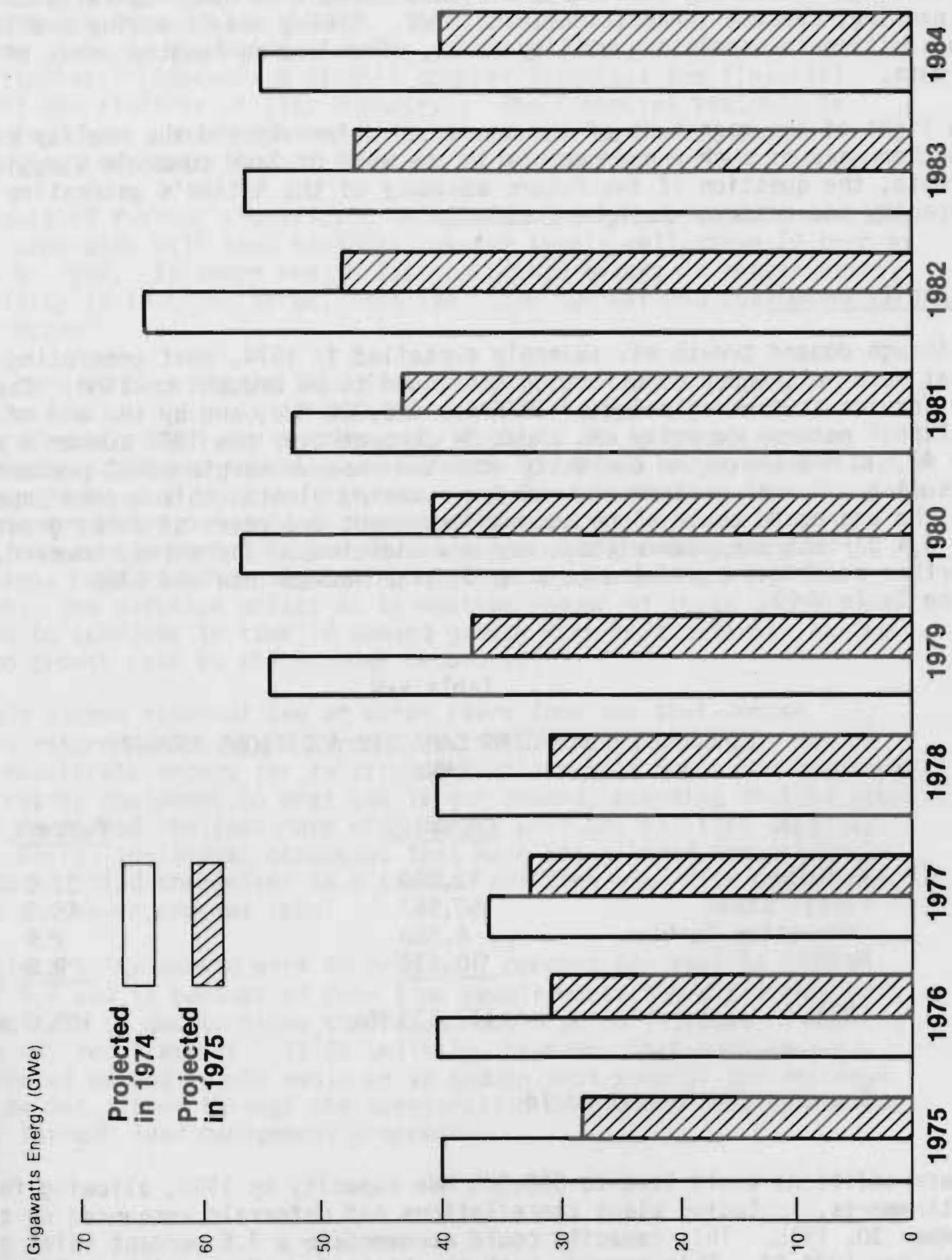


Figure V-4
Change in Planned Electric Generating Capacity Additions
Comparison of 1974 and 1975 Forecasts

Source: National Electric Reliability Council

Demand uncertainties, due to higher prices and conservation, were underscored as critical to cancellation and deferral decisions. It was frequently indicated that the lack of appropriate and expeditious rate relief, combined with general economic conditions and insufficient earnings to raise outside financing, created financial difficulties. Siting and licensing problems, in addition to escalating utility costs, often caused lengthy delay of many plants.

In light of the magnitude of the announced deferrals and the reality of another wave of such announcements in the wake of last summer's sluggish growth, the question of the future adequacy of the Nation's generating capacity and reserves must be examined.

Capacity Growth

Although demand growth was severely curtailed in 1974, most generating plants that were well under construction continued to be brought on line. Capacity in service at the beginning of 1975 was 476,000 MWe, and by the end of 1975, national reserve capacity was about 34 percent over the 1975 summer's peak, or 49,500 MWe above the currently accepted reserve margin of 20 percent. Assuming a normal retirement rate for existing plants, this excess capacity in the aggregate could alone accommodate about two years of sales growth at 5.4 percent per year without any new additions. There are, however, further additions scheduled to come on line between now and 1980 (see Table V-9).

Table V-9

SCHEDULED GENERATING CAPACITY ADDITIONS 1976-79
(MWe)

	Capacity	Percent
Nuclear	41,589	37.0 %
Fossil Steam	50,987	45.3
Combustion Turbine	8,880	7.9
Hydro	10,474	9.8
TOTAL	112,430 MWe	100.0 %

Source: Electrical World

These additions would lead to 620,000 MWe capacity by 1980, allowing for plant retirements, including plant cancellations and deferrals announced up to September 30, 1975. This capacity could accommodate a 7.6 percent sales growth rate for 1974-80. This exceeds both the historic and the highest FEA growth estimates, as summarized in the forecast section of this chapter, even assuming an accelerated shift to electricity in the face of interim shortages of natural gas and oil.

Because of current excess reserve and capacity additions nearing completion, there does not appear to be a significant probability of a capacity shortage through 1980 on a national basis. This does not mean, however, that local shortages would necessarily be avoided. There are a number of utilities facing continuing financial problems. These companies may be forced to defer construction plans to the point of being unable to meet the service needs of their territories. (Appendix B of this chapter discusses the financial situation of the electric utility industry.) The financial analysis in Chapter VI indicates that there may be some problems to be surmounted if a continuing, adequate flow of funds is to be provided for this industry.

In the absence of further significant delays, currently projected generating capability schedules will keep national reserve levels well above 20 percent until 1983 or 1984. If there are in fact continued delays in construction, the probability is that the large, long lead time nuclear and coal plants will be most affected.

The danger here is more subtle than just the potential for an aggregate capacity shortfall. The bulk of the deferrals of nuclear plants involve capacity ordered for delivery in the early 1980's. It is an attractive alternative for a company to delay commitments for these large, expensive, long-term projects when they are not necessary for immediate needs. Many of these plants are being deferred in the expectation that power will be available from a neighboring system in the event of a growth upsurge. In some cases, however, the neighboring utility may be making a similar calculation. The question arises as to whether enough of these plants could be restored to schedule in time if demand growth were to accelerate to the pre-embargo growth rate as the economy recovers.

If it should become apparent two or three years from now that demand growth will return to its seven percent historical rate, utilities may be forced to accelerate orders for quickly available simple cycle and combined cycle generating equipment to meet the larger demand, assuming that no steps were taken to spread the load more efficiently over the existing capacity. On a local basis, individual companies that have not planned adequately to meet demand may find themselves in a similar position even with overall growth lower than the seven percent rate.

If total electricity demand were to grow at 7 percent per year to 1985 instead of 5.4 and if because of lead time requirements the difference were made up entirely of gas turbines the result would be an increase of about 2 MMB/D in oil requirements. It is unlikely, however, that such an acceleration of demand growth would be so sudden that some of the increase could not be met either through the acceleration of planned coal or nuclear plants, or through load management programs.

If, on the other hand, the utilities were to build to meet a demand growth of 6.4 percent through 1985 as projected in the Electrification Scenario discussed later, they would need almost 873,000 megawatts of generating capacity, instead of the 785,000 MWe projected for the Reference Scenario. The additional capital requirement would be about $46 billion assuming an acceleration of plant lead times which would lower total plant costs considerably. Should actual demand instead be the 5.4 percent projected in the Reference Scenario, the cost of carrying the extra capacity would be $7.0 billion, or about 7.6 percent of total revenues.

All of the above projections were made on the assumption of a continuing decline in the average load factor for the system, with peak demand continuing to grow a half percent faster than average demand. If this trend can be stopped or reversed, the available capacity would be able to handle substantially larger loads, and potential problems resulting from inadequate capacity would be reduced.

Load Management

The total amount of capacity required in 1985 or beyond depends on more than just the growth in total demand. It is contingent on the differential between growth for peak and for average demand.

Under the traditional declining block rate structure, and in the absence of technological systems to control demand peaks, the annual load factor (average load/peak load) in the United States has declined from nearly 66 percent in 1960 to an estimated 61 percent in 1975. This phenomenon reflects demand patterns, and has a direct effect upon plant utilization. Plant utilization, in turn, directly affects capacity expansion requirements, generation efficiency (heat rate), and fuel mix.

The benefits to be derived from implementation of load management techniques which focus on plant utilization could be substantial. If aggregate capacity utilization of the plants in service can be improved, less plant will be required. In that case, further deferrals would not necessarily constitute a major problem except in isolated instances.

A number of European nations have successfully attacked their own load factor problems through load management, a strategy of shaping demand patterns through pricing and positive load controls. For example, the following load factors were achieved in 1972:

	Annual Load Factor	Winter Load Factor
France	70 %	77 %
Germany	67	75
Belgium	69	76

All of these load factors are substantially above the 1975 U.S. figure of 61 percent. Of particular interest, however, are the winter seasonal load factors on these winter peaking systems. The temperature-sensitive load during the winter peaks--electric heating--has been largely moved into the off-peak hours, improving the seasonal load factor and producing a high annual load factor even in the absence of a summer air conditioning load for seasonal balance.

U.S. utilities, on the other hand, tend to be summer peaking, with a heavy temperature-sensitive air conditioning load. However, it is possible that peak load can be moderated through a combination of pricing and load controls, with a resultant increase in load factor. The technology for air conditioning load management is available and has been demonstrated to be cost effective, particularly for the commercial buildings which cause severe load factor problems.

Given the potential for managing both summer and winter temperature-sensitive loads in the U.S., it appears that annual load factors higher than the European winter seasonal factors, are achievable in this country. A 1985 annual load factor of 67 percent appears to be a reasonable and attainable target, assuming national support of load management and associated time-of-day pricing. Such a load factor could be achieved if peak load growth is held to one percent below sales growth, a pattern judged to be feasible on the basis of European experience, generally accepted elasticity estimates, and the preliminary results of domestic field tests funded by the FEA and the National Science Foundation.

The combination of a declining load factor and an increased aggregate reserve margin (from 20 percent in 1967 to nearly 34 percent in 1975) has caused the deterioration of the capacity factor (average output/rated capacity) from 52 percent in 1967 to an estimated 44 percent in 1975.

Again by controlling the growth of peak demand to one percent below the sales growth rate and at the same time decreasing reserve margin to 17.5 percent it is estimated that a capacity factor of 57 percent would be reached by 1985. This improvement in capacity utilization would reduce the need for new capacity by up to 90,000 MWe by 1985 and by about $60 billion in capital requirements. It would also achieve a substantial reduction in the average retail price of electricity.

Utilities have always been cognizant of the need to add new loads in a manner which would improve both load and capacity factors. When the cost of expanding capacity was lower than the average cost of existing capacity, however, the economic incentive to improve load factors was largely blunted.

Rate structures have not generally differentiated between on-peak and off-peak usage, despite the fact that it is the former which forces the additional costs of capacity expansion. Even though the incremental cost of capacity was, until recently, lower than the average cost of installed capacity, it was nevertheless an increment; it increased the cost of service more than would higher utilization of existing capacity. Because electricity prices were falling, price structures did not reflect this point.

The gains to be derived from peak load pricing can be augmented by direct load management techniques. These techniques are designed to provide control by the utility of the maximum coincident demand on the system. They include such approaches as time-controlled water heating which is turned off during peak hours, heat storage systems which provide heat during peak hours in substitution for utility power, and load shedding devices which turn off selected equipment for short periods when the system maximum load is being approached.

ELECTRICITY FORECAST - 1985

Demand

During the period 1952-72 electricity consumption in the United States grew at a compound growth rate of 7.3 percent per year, more than twice the growth rate of total energy consumption which grew at 3.6 percent over the same period. During this time, prices for energy tended to hold steady in real terms or declined slowly. However, at the time of the Arab embargo which began in 1973, there was a sudden large increase in the overall price of energy to the U.S. economy. It is projected that these price increases, coupled with the increasing consciousness of energy use, will lead to a decrease in the growth rate for total energy consumption to 2.8 percent, should oil prices remain at about $13, and slightly higher rates should oil prices decline from their current levels.

The growth rate through 1985 projected for electricity consumption under the $13 Reference Scenario is 5.4 percent, slightly less than twice the overall growth rate of total energy, but still showing a tendency to grow substantially faster than overall energy usage. The range of growth rates projected for electricity over the different scenarios reviewed in this report is from a low of 4.9 percent in the Conservation Scenario to a high of 6.4 percent in the Electrification Scenario. The range is consistent with forecasts from recent studies of potential growth rates. An average of eight such studies completed since mid-1973 shows a mean projected growth of 5.6 percent (see Table V-10).

Table V-10

COMPARISON OF RECENT ELECTRIC DEMAND GROWTH STUDIES

Source and Year of Study	Projected Growth Rate 1974-1985
Oak Ridge - 1973	4.4 %
Arthur D. Little - 1974	6.4
Lawrence Livermore Lab. - 1974	5.6
Hudson Jorgenson - 1974	5.5
Technical Advisory Committee - FPC - 1974	6.0
Oak Ridge - 1975	5.1
Westinghouse - 1975	5.0
Electrical World - 1975	5.8
Average	5.6 %

The above projections all relate to the growth rate of total annual consumption of electric power. However, the variable which determines the requirement for plant construction is the growth in annual peak generation requirements. Reserve margins are measured as the percent of available capacity above the peak requirement on the system. The total plant requirement is therefore a function of peak rather than average growth. There are two different assumptions made about the relationship between peak growth and average growth in the various scenarios. The business as usual assumption is a projection of deterioration of the load factor through a continuation of the historical trend of peak growing half a percent faster than baseload. In the scenarios using conservation demand specifications, the assumption is made that an active load management program can reduce peak growth relative to average by one percentage point. The total range of growth rates of demand for peak and therefore for plant construction varies between 3.9 percent and 6.9 percent.

Supply

The mix of powerplants used by the electric utility industry has changed significantly over the past 15 years. In 1960 more than half the kilowatt-hours were produced by coal-fired steam plants. Although electricity generation from coal has increased absolutely since then, the relative use of oil and nuclear power has grown much more rapidly. In particular, oil generation dramatically increased during 1969-73 as a result of more stringent state environmental laws, some of which were responding to the Clean Air Act Amendments of 1970. Generation from natural gas and hydropower increased in absolute terms, but like coal, declined in relative importance nationally.

Except for New England, all regions east of the Mississippi are primarily dependent on coal for electricity production. In addition, since 1960, there is increased emphasis on coal and reduced emphasis on natural gas in the West North Central. The Mountain region has also increased its usage of coal for electricity generation although hydropower and natural gas continue to be important. New England has almost completely switched out of coal and into oil and nuclear power, relying on the latter for about 25 percent of its electricity. The Pacific region has increased its relative dependence on hydroelectricity, enabling it to deemphasize the use of natural gas for electricity production. The West South Central has changed little since 1960, still relying almost entirely on natural gas for its powerplant fuel.

The major swing projected between 1974 and 1985 is that nuclear power grows very rapidly and tends to replace, on a percentage basis, much of the oil and gas fueled generation. The relative share of nuclear power grows more than fourfold. Generation from coal essentially maintains its market share, while oil and natural gas both decline to less than half their present share, although the absolute amount of oil and gas use declines by only one quad (about 15 percent). Hydroelectricity decreases slightly as there are fewer available sites for development (see Table V-11).

By 1990, on-line nuclear capacity could increase to as much as 266,000 megawatts. New uranium enrichment capacity would have to be brought on stream sometime prior to 1985. A discussion of the nuclear fuel cycle is contained in Appendix A of this chapter.

There are a number of regional disparities from the national pattern in 1985 which generally result from differences in the natural geography of the regions, such as the availability of large amounts of hydroelectric supply, and long transportation distances from coal mines, resulting in higher prices for what would otherwise be relatively cheap and abundant coal supplies.

- New England will have had the largest commitment to nuclear power, deriving 41 percent of its net generation from this source. Another 27 percent is projected to come from coal, which is substantially larger than its contribution today. Practically all of the remaining electricity is expected to be generated from oil.

- The South Atlantic, East North Central and West North Central regions are expected to show a substantially higher dependence upon coal than the Nation as a whole and practically none on natural gas. The South Atlantic and East North Central regions depend more than average on nuclear, while West North Central is low in nuclear, but highest in coal. Hydropower is also small.

- The East South Central region has a significantly larger than average contribution from nuclear (37.3 percent) in 1985 and a slightly larger than average contribution from coal. This region is projected to have the smallest dependence on oil and natural gas.

- The West South Central in 1985 shows a continuing and exceptionally high dependence upon natural gas, which accounts for 54 percent of

Table V-11

PERCENT CONTRIBUTION FROM EACH FUEL TO REGIONAL AND TOTAL U.S. ELECTRICITY GENERATION

Region	Coal			Oil/Gas			Nuclear			Hydro			Other		
	1960	1974	1985*	1960	1974	1985*	1960	1974	1985*	1960	1974	1985*	1950	1974	1985*
New England	50.3	7.4	26.8	31.7	61.3	28.4	0.1	24.4	41.0	17.9	6.9	3.9	---	---	---
Middle Atlantic	69.3	42.7	47.9	18.5	36.2	13.6	0.2	8.5	29.9	12.0	12.6	7.3	---	---	1.2
East North Central	93.5	82.0	66.4	3.8	8.7	5.8	0.2	8.3	26.3	2.5	1.0	0.6	---	---	1.0
West North Central	40.3	54.4	70.1	46.9	27.2	4.9	---	7.7	17.2	12.6	10.7	7.7	0.2	---	---
South Atlantic	66.3	54.9	52.6	20.2	32.5	10.3	---	7.4	32.0	13.5	5.2	7.3	---	---	1.2
East South Central	74.5	76.5	50.8	5.5	5.4	4.5	---	3.6	37.3	20.0	14.5	7.4	---	---	---
West South Central	---	3.0	20.6	95.7	92.6	55.3	---	0.2	22.8	4.3	4.2	1.4	---	---	---
Mountain	11.8	46.3	48.7	36.6	23.2	16.9	---	---	14.9	51.6	30.5	15.2	---	---	3.7
Pacific	---	1.7	4.7	42.0	27.8	19.9	---	2.8	10.2	58.0	66.7	62.2	---	1.0	2.5
Nation	53.5	44.5	45.4	27.1	33.2	16.1	0.1	6.0	26.1	19.3	16.1	11.5	---	0.1	1.0

* 1985 $13 Reference Scenario

the total generation in the region down from 87 percent in 1974. However, all but 12,000 MWe of the gas-fired plant is operating at intermediate load in this region by 1985. The reduction in the use of gas comes from the less intensive use of these plants due to additions of nuclear and coal-fired baseload plants. While the nuclear contribution is close to the national share, coal's share is less than half the national average.

- The Pacific region deviates most dramatically from the national composite in 1985, deriving the majority of its electricity from hydropower (62.2 percent). Most of the remainder is generated from oil. Nuclear electricity is small but significant.

In all analyses where the price of oil is $13 or higher and gas is deregulated, the full cost of existing oil and gas-fired power is sufficiently high to make it attractive to reduce almost all such plants to intermediate load use by 1985. About 12,000 MWe of gas-fired plant in the West South Central region continue to operate at baseload because not enough new baseload plant would be built yet to replace it. At a price of $2/million Btu (about $12/barrel for oil or $2/Mcf for natural gas) the fuel cost alone of petroleum nears 20 mills per kilowatt-hour, which is close to the total cost of power delivered from a nuclear or coal-fired plant. The result is that almost none of the existing base load oil and gas-fired plant is in service as baseload equipment by 1985. This equipment is currently concentrated on the eastern seaboard and on the West Coast for oil-fired plant, and the Southwest, for gas-fired plant. The result is a major swing in the fuel mix if the price of oil turns out to be $8 rather than $13, with higher oil and gas consumption and lower coal usage.

This regional picture is reasonably consistent across all scenarios but two, the $8 Reference and the Regional Limitation Scenarios, which illustrate changes that could cause substantial departure from the pattern.

An increase in the price differential between oil and coal has its first impact at intermediate loads. The cost of power from plants that operate only one third of the year is more sensitive to the fixed overhead, which is relatively high per kilowatt-hour of output, than the cost of power for baseload.

Under the $8 Oil Scenario, simple cycle turbine becomes attractive for intermediate load application in place of coal-fired plants because the lower initial cost added to the smaller relative fuel price differential shifts the economic decision point. Over 10 percent of total power is generated by these simple cycle turbines versus 1.6 percent in the Reference case. Apart from this change, the pattern remains largely as discussed above.

The Regional Limitation Scenario produces a very similar result. It includes among the events modeled a nuclear moratorium which restricts the total available nuclear capacity increase through 1984 to an additional 61,000 megawatts. All new coal-fired plants are required to use both scrubbers and low-sulfur coal, which raises the price for new coal-fired power enough to shift the balance in favor of simple cycle turbines for intermediate load use.

In this case only the two western regions continue the Reference Scenario pattern of coal expansion. Both regions require scrubbers on new plants in all strategies and low-sulfur coal is relatively low priced. The West South Central region also shifts to coal rather than increasing oil and gas, but it starts from the highest gas-fired base of all the regions.

In addition to the changes in fuel mix in the various scenarios there are also large changes in the numbers of plants needed to meet the overall demand requirements, which are a function of peak load growth rather than the growth in average load. The scenario with the lowest peak load growth is the Conservation Scenario which has a growth rate for peak load over the 1974-1985 period of 3.9 percent. This scenario requires an increase of 243,400 MWe of capacity. The Electrification Scenario, on the other hand, projects an average compound growth in peak load of 6.9 percent and requires 383,000 MWe of new capacity on line. The major swing in capacity takes place in the coal-fired plants. Nuclear plants are limited over the time period by the long planning lead times required to bring these plants on stream. However, coal plants can be built on shorter notice and are projected to make up the difference in required capacity (see Table V-12).

The economic choice of scrubbers for coal plants for baseload service is variable from region to region because of the variations in coal prices and transportation costs. In the eastern regions, where high-sulfur coal is readily available at lower prices and where low-sulfur coal is more difficult to obtain, scrubbers tend to be built. The middle of the country tends to use low-sulfur coal as much as possible since the savings in price from high-sulfur coal are not adequate to overcome the capital costs of adding scrubbers. Scrubbers are installed in the West because state regulations tend to make them mandatory.

Table V-12

ELECTRIC POWER PLANT CAPACITY ADDITIONS 1975-84
$13 IMPORTED OIL
(Thousands of Megawatts)

Plant Type	Conservation Scenario	Accelerated Scenario	Reference Scenario	Electrification Scenario
Nuclear	97.4	105.8	105.4	126.1
Coal	96.2	77.5	156.7	201.5
Oil-fired	13.7	13.7	13.7	13.7
Gas-fired	.2	.2	.2	.2
Simple Turbine	2.0	1.1	33.1	38.8
Hydro	28.3	28.3	28.3	28.3
Other	5.6	22.7	5.6	22.7
Total	243.4	249.3	343.0	431.3

Price

The average price of electricity in the various scenarios ranges between a low of 25.96 mills per kWh in the Accelerated Scenario with conservation and a high of 31.12 mills per kWh in the Regional Limitation Scenario. These prices compare with the current 1975 national average price of approximately 27 mills per kWh and a Reference Scenario price of 29.73 mills per kWh. These prices are relatively stable over the ten years and over the total range of scenarios. The exact prices are a function of the fuel mix, of the types of plant built in the interim, and of the cost of those plants. As was shown in Table V-1, the nuclear power plants deliver the cheapest power available from new baseload plants, approximately two mills cheaper than from a coal-fired plant. However, the nuclear plants expected in 1985 must already be in the planning and licensing stage if they are to be delivered to meet the demand in that year. There is consequently a limit on the total number of such plants that can be expected by 1985. These limits are incorporated in the analysis for each region, based on data filed with the Nuclear Regulatory Commission concerning proposed plants and delivery schedules.

The tendency is to provide coal-fired plants for all remaining baseload requirements except in regions having available large amounts of either hydroelectric or geothermal power which are yet cheaper. Coal is chosen because it is available at prices ranging from $1.38 to $0.46 per million Btu compared with the price of approximately $2 per million Btu for oil or gas in the $13 Reference Scenario. When coal plants are built, an "opportunity cost" is calculated in each region which measures the incremental cost to consumers of not being able to build more nuclear plants. This cost ranges from 4.0 mills per kWh in the Northeast to 0.8 mills/kWh in the Mountain States in the $13 Reference case. The regions where this cost is relatively high are Northeast, Mid-Atlantic and East North Central.

In cases with accelerated plant building schedules and consequently lower cost of plants, the economics of the plants shift slightly, and the overall price of electricity tends to decline. The lowest price is found in the Accelerated Scenario with conservation because this embodies both lower cost plants through accelerated building schedules and more efficient use of the existing and new plants through higher load factors due to load management.

The highest power cost is encountered in the Regional Limitation Scenario because nuclear plants are limited to those currently holding building permits, which cuts nuclear builds to almost half the level otherwise projected. In addition, this scenario requires scrubbers on all new coal-fired plants and the use of high-sulfur coal. Both of these conditions increase the price of electric power.

One other action embodied in the model leads to increased capital cost but does not necessarily lead to increased cost of power. This is required conversion of 11,316 megawatts of capacity from either oil or gas to coal. These plants were ordered to make these changes in mid-1975 under the Energy Supply and Environmental Coordination Act. These conversions will require additional capital investment but will cause these plants to burn coal rather

than oil and gas. By 1985 the economies from the use of the lower cost fuel will tend to offset the cost of the capital investment.

It appears, then, that the price of electricity cannot be expected to resume declining in real terms as was the norm for the 1950's and 1960's. The price increases brought about by the increase in fuel prices in 1974 can be mitigated to some extent on a regional basis, but the increasing cost of new generating plant will prevent the national utility system from bringing costs below those now prevailing. The largest cost benefits from switching to cheaper fuels will be realized in the Northeast and Mid-Atlantic regions where the Reference Scenario prices decline by 15 and 11 percent. The largest cost penalties are paid in the East South central and West South Central regions where the price rises by 68 and 54 percent. The dominant reason for the price reductions is the shift from suddenly expensive imported residual oil to nuclear fuel. The increase in the West South Central region results when the dominant fuel, natural gas, increases in price due to short supply. The price increase in the East South Central region occurs as the production mix continues to shift away from cheap, but fully exploited, hydroelectric power.

The Electrification Scenario is designed to test the possibilities for substituting electricity--which can be produced from domestically available coal or uranium--for imported oil or scarce natural gas. It assumes a prohibition on the use of all oil and natural gas in baseload electricity generation and on the construction of new oil and gas powerplants after 1977 for intermediate load. It includes an accelerated conversion of existing boilers to coal, greater nuclear capacity additions, and greater solar and geothermal energy. It also assumes that no further oil or gas heating systems may be installed after 1977 for residential or commercial use, and that part of new industrial demand for oil and gas will be shifted to electricity or coal. This restriction was set up to show an extreme swing in electricity use. In practice, such a program would result in large cost increases, both to the homeowners and the industrial users. It is not clear that even this amount of switching could be successfully induced over the period.

The result shows that some substitution is possible, and about 1 MMB/D of oil imports might be saved. In addition, 1.5 Tcf per year of natural gas is freed up to be distributed to other users. About 350,000 B/D equivalent of the savings comes from changes in the fuels used by the utilities, largely due to an accelerated use of nuclear power, while the remainder comes from direct substitution of electricity for oil or gas at the consumer level. The price of power is pushed up in this case, despite the assumption of wider use of nuclear power from the cheaper, shorter lead time plants. More new plants are built which deliver above average cost power, and the price of coal is pushed up by substantially increased demand.

Only in the case which includes both reduced plant costs and load management, the Accelerated Scenario, does the price remain stable at current levels on a national basis.

Capital

The large variation in the total requirement coupled with the variations in plant cost depending on the extent to which efficiencies can be introduced in the construction cycle tend to lead to widely different capital requirements for the industry over the period. The capital costs range between $215 billion and $323 billion over the ten years from 1975 to 1984. The low capital need is found in the Accelerated Scenario which embodies an active load management program, and therefore only builds 249,300 MWe of new capacity. The high capital need is found in the Electrification Scenario in which 431,300 MWe of new capacity are built to meet higher power demands (see Table V-13). This subject is discussed in more detail in Chapter VI.

Table V-13

CAPITAL REQUIREMENTS OF THE ELECTRIC UTILITY INDUSTRY
(Billions of 1975 Dollars)

	Reference Scenario	Accelerated Scenario	Electrification Scenario
Nuclear Generation	58.0	52.9	63.0
Other Generation	81.8	51.0	96.8
Transmission and Distribution	97.9	72.7	111.9
Increase in work in progress	38.5	38.5	50.9
Total	276.2	215.1	322.6

PUBLIC REGULATION AND UTILITY COST STRUCTURE

State regulatory commissions ultimately affect and are affected by changes in utility costs. The close relationship between regulatory powers and the financial health of the electric utility industry, capacity utilization, sales growth and fuel mix, has come into sharp focus since the recent cost increases led to higher prices for electricity.

In terms of installed capacity, number of customers, and kilowatt-hour sales, about 78 percent of the electric utility industry in the United States is presently investor-owned. These private companies are regulated by public authorities at both the State and Federal levels of government. State authorities regulate intrastate transactions, while Federal authorities regulate interstate transactions, environmental protection standards, private hydroelectric projects, and nuclear plant licensing.

The predominant role in public regulation of investor-owned utilities, however, remains with the States. State regulatory commissions, which are either directly elected by the public or appointed by elected officials (the governor or the legislature) have regulatory powers over such matters as:

- determining the rate base
- establishing the authorized rate of return
- setting rate structures (tariffs)
- approving reorganizations, mergers and consolidations
- prescribing accounting, auditing and reporting standards
- ensuring safety and reliability
- certifying and licensing plant expansion

Of the 50 States, all but two have most of these powers.*

It is in exercising these powers that regulatory commissions ultimately influence nearly all aspects of the electric utility industry.

Prior to 1970, electricity was a declining price item for the consumer, because utility expansion was a declining cost item for the utilities industry. Since the cost of additional production capacity, particularly generating stations, was lower than that of capacity already installed, expansion could be financed relatively easily and resulted in a lower average cost and retail price per kilowatt-hour. There was a strong incentive, consequently, to expand capacity rather than to improve the utilization of existing capacity.

These conditions prompted regulatory commissions to approve rate structures which tended to encourage both electricity sales and capacity expansion. Such rate structures priced electricity so that the price charged per kilowatt-hour decreased as the number of kilowatt-hours used per month increased the so-called declining block rate structure. Further, in this period of declining costs, there was little concern regarding regulatory delays in approving new rates, since these delays were not creating financial difficulties for either consumers or utilities.

When costs turned upward, however, regulatory lags began to impact adversely on utility earnings. In the face of declining profitability, most rate commissions began to allow utilities to pass-through fuel costs without prior review. The extent of such increases in 1974 created serious difficulties for the commissions. The basic mandate to the commissions to ensure the lowest rates consistent with the ability of the utility to attract sufficient capital has, as a consequence of changing conditions, come to be interpreted in divergent ways.

---

* Neither South Dakota, nor Nebraska has a State regulatory commission for investor-owned utilities; the latter prohibits such utilities in the State.

Historically the focus of rate questions related to aggregate revenues and the allocation of charges to customer classes and sub-classes was based on accounting procedures and historical cost allocation systems which resulted in the declining block rate structure.

Since the costs for new capacity are now higher than for old, a new means of allocating charges to reflect actual costs of service and to improve capacity utilization is inevitable and necessary. It is also important that the feedback effects which rate structures have on both total demand and demand patterns be taken into account with explicit consideration given to the contribution of peak load growth to total utility costs and consumer prices. The emphasis that was once placed on aggregate revenues for rate-setting purposes may have to shift to a closer focus on long-run efficiency questions.

ALTERNATIVES TO CENTRAL UTILITY ELECTRICITY

The scenario evaluations show that only under optimistic conditions does the price of electricity hold reasonably stable in real terms at current prices.

However, should plant costs continue to rise steadily and plant delays continue to worsen, end users of electricity may begin to seek alternate means to fullfill their needs, either through other energy sources or through generation of power on their own premises. The higher the cost of central station power becomes, the more likely it is that economical means will be found to supplement the public utility. While some of these would be advantageous from the viewpoint of national energy policy, e.g. small scale solar generation, others would not, e.g. local gas turbines.

Forecasts of electricity demand generally do not consider the possible impacts of available alternatives to remotely-generated utility electricity. Such alternatives are on-site generation of electricity at the point of consumption; and utilization of "waste" heat from electricity generation for purposes otherwise met by electric heating, or by industrial steam.

The widespread adoption of these techniques as well as other alternatives to low-grade electric heating, (such as decentralized solar power for space and water heating) for which the necessary technology is presently available, could have a substantial impact upon the future demand for central power plant electricity.

On-site generation of electricity by industrial plants now accounts for about 99 billion kilowatt-hours annually in the United States, or about 5 percent of total electricity production. Perhaps more meaningfully, this amount is equal to about 14 percent of utility electricity sales to industrial customers.

In addition, an undetermined amount of electricity is self-generated by hotels, laundries, hospitals, and other institutions.

Waste heat utilization already adopted by utilities in their combined cycle turbine generators can be directed to end-use heating purposes in lieu of electricity. Approximately two-thirds of the energy consumed in generating electricity is presently lost; worse, it is considered a source of air and water pollution (thermal pollution). Waste heat utilization technology is better developed in Europe, where it is frequently used to produce hot water or steam for both space heating and industrial processes.

A recent study made for Michigan Public Service Commission* suggests that combining industrial steam boilers with generating equipment could provide up to 71,000 MWe of electric capacity by 1985 for an effective capital cost of $120/KWe, almost one-fourth the current price for such generating equipment standing alone. Furthermore, since a different overall thermodynamic cycle is used, more of the Btu content of the fuel would provide useful work. The result is lower fuel costs and higher efficiency.

The development of such alternatives to central generating stations could impact significantly on the electric utility industry. What remains to be seen is how far the rising cost trends that have brought the industry to its present condition will continue. The higher the price of electricity from the existing system, the stronger the likelihood of alternative generation.

SUMMARY

The most significant change in the electric utility industry is the marked increase in plant costs. This increase has only begun to be reflected in plants that are now in the rate base. However, as the newer, more expensive plants are brought on line over the coming decade, the higher cost will have to be reflected in rates. This upward pressure will counterbalance the savings to be realized through a shift to the cheaper, domestically available coal and uranium fuels. The result will be continuing price increases, or, at best, constant real prices for electric power.

The rising plant costs are also at the root of the companies' financial difficulties. The major portion of the full investment in a new generating plant is made years ahead of the date the plant enters service and becomes an earning asset. As plant costs rise, the construction work in progress rises. In 1974 it reached one-sixth of total electric utility assets for the investor-owned segment of the industry. At the same time the annual investment level rose to equal 35 to 40 percent of revenues. The result has been a sharp jump in the amount of external financing needed.

---

* Energy Industrial Center Study, prepared for the Office of Energy Research and Development Policy, National Science Foundation, June 1975.

Because the trends of rising costs and increased financing needs have converged, growth has become less desirable for both companies and regulators. If the rate of growth of demand slows also, there would be relatively little problem. However, while rising prices may restrain growth to some extent, other forces may encourage it. Natural gas shortages may encourage the substitution of electricity. Greater assurance of availability amy make electricity more attractive despite its higher price per Btu than that of fossil fuels. In the long run, it is the most flexible way to harness and distribute renewable energy sources.

Any acceleration in the growth in demand for power brings with it an increase in stress on the industry. Financing needs in advance of completion increase rapidly, while the price charges at the time of start-up tend to discourage the demand for which the equipment is needed. Both forces have introduced an unaccustomed note of uncertainty into utility planning.

FEA projections center around a growth in electric energy demand of about 5.4 percent. But the extremes in growth are in peak demand growth, ranging from a 3.9 to 6.9 percent, with a concomitant range of new generating plant requirements. At the high end, however, the projection is still below pre-embargo forecasts.

Lower projected demand growth should reduce some of the financial pressures on the industry. Capital market conditions have improved since 1974, but the industry remains vulnerable should money tighten, or a sudden spurt of demand materialize late in this decade, after the current excess reserves have been absorbed. Planning efforts have become much more complicated, as price and alternate fuel availability calculations must now be included. Underestimating growth endangers reserve margins, and corrective action is likely to involve at least a temporary increase in the use of scarce and expensive oil. Overestimating growth would lead to excess reserves with an accompanying excess in costs which may tend to dampen the rate at which demand will rise to match capacity.

To some extent, utilities can seek to reduce the cost of new generating plants or to gain greater control over their load growth. The strategies reviewed in this Report investigated some of the benefits from both possibilities, but even in the Accelerated Scenario which incorporates both cheaper plants and load management could only hold the average price of power steady at current price levels in real terms.

Because the trends of rising costs and increased financing needs have converged, growth has become less desirable for both companies and regulators. If the rate of growth of demand slows also, there will be relatively little problem. However, while rising prices may restrain growth to some extent, other forces may encourage it. Natural gas shortages may encourage the substitution of electricity. Greater assurance of availability may make electricity more attractive despite its higher price per Btu than that of fossil fuels. In the long run, it is the most flexible way to harness and distribute renewable energy sources.

Any acceleration in the growth in demand for power brings with it an increase in stress on the industry. Higher growth rates lead to increased construction expenditures which require immediate financing. Cash inflows do not begin until the plants go into service at which time rates rise. These increases in turn tend to discourage the demand for which the equipment is planned. These forces have introduced an unaccustomed note of uncertainty into utility planning.

FEA projections center around a growth in electric energy demand of about 5.4 percent. But the extremes in growth are in peak demand growth, ranging from a 3.9 to 6.9 percent, with a concomitant range of new generating plant requirements. At the high end, however, the projection is still below pre-embargo forecasts.

Lower projected demand growth should reduce some of the financial pressures on the industry. Capital market conditions have improved since 1974, but the industry remains vulnerable should money tighten, or a sudden spurt of demand materialize late in this decade, after the current excess reserves have been absorbed. Planning efforts have become much more complicated, as price and alternate fuel availability calculations must now be included. Underestimating growth endangers reserve margins, and corrective action is likely to involve at least a temporary increase in the use of scarce and expensive oil. Overestimating growth would lead to excess reserves with an accompanying excess in costs which may tend to dampen the rate at which demand will rise to match capacity.

To some extent, utilities can seek to reduce the cost of new generating plants or to gain greater control over their load growth. The strategies reviewed in this Report investigated some of the benefits from both possibilities, but even in the Accelerated Scenario which incoropates both cheaper plants and load management could only hold the average price of power steady at current price levels in real terms.

Appendix V-A

THE NUCLEAR FUEL CYCLE FOR LIGHT WATER REACTORS

INTRODUCTION

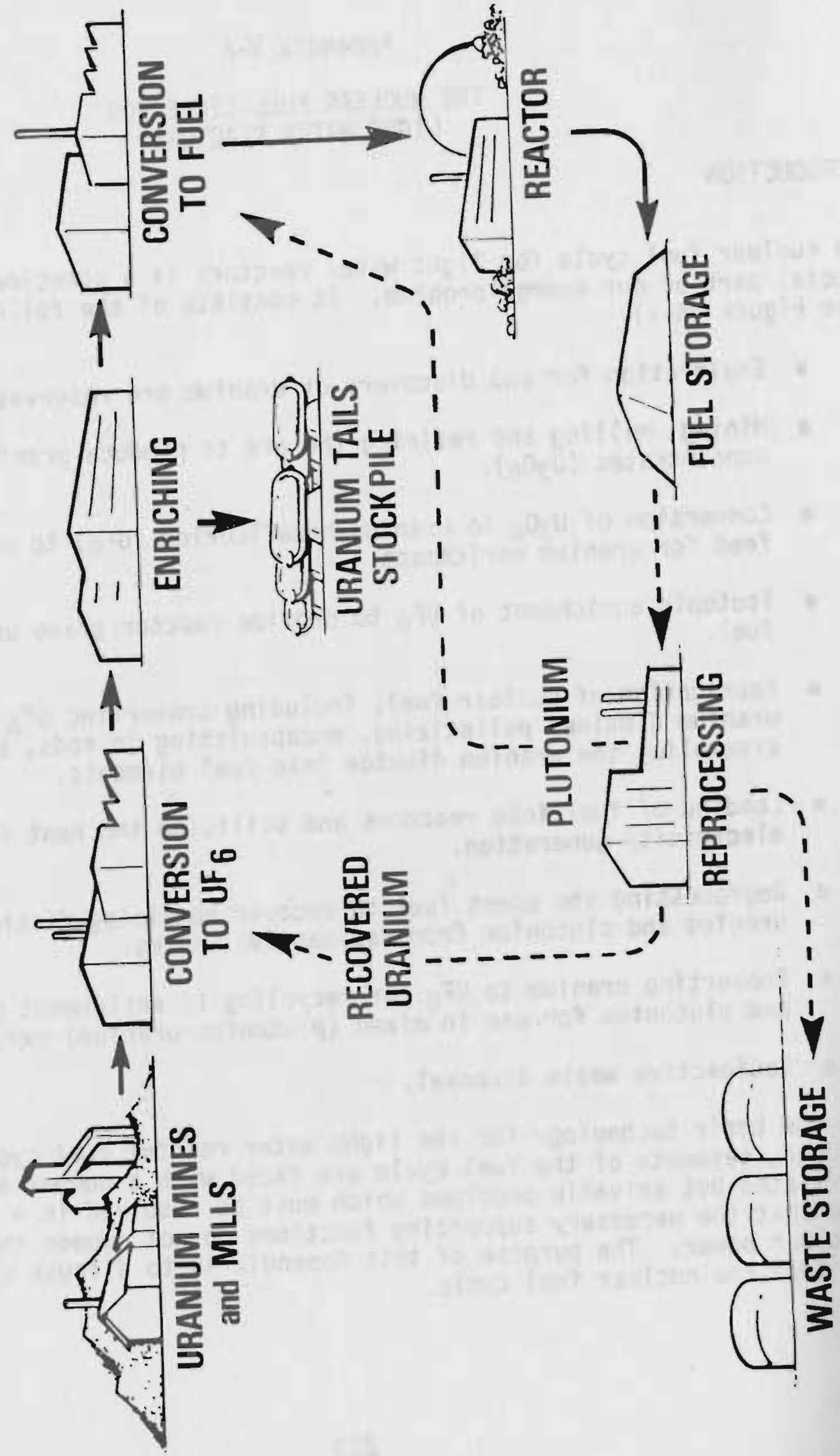
The nuclear fuel cycle for light water reactors is a sometimes ignored, but crucial part of our energy problem. It consists of the following steps (see Figure VA-1).

- Exploration for and discovery of uranium ore reserves.
- Mining, milling and refining the ore to produce uranium concentrates (U_3O_8).
- Conversion of U_3O_8 to uranium hexafluoride (UF_6) to provide feed for uranium enrichment.
- Isotopic enrichment of UF_6 to provide reactor grade uranium fuel.
- Fabrication of nuclear fuel, including converting UF_6 to uranium dioxide, pelletizing, encapsulating in rods, and assembling the uranium dioxide into fuel elements.
- Loading of fuel into reactors and utilizing the heat for electricity generation.
- Reprocessing the spent fuel to recover remaining fissionable uranium and plutonium from radioactive wastes.
- Converting uranium to UF_6 for recycling to enrichment plants and plutonium for use in mixed (plutonium-uranium) oxide fuels.
- Radioactive waste disposal.

While the basic technology for the light water reactor fuel cycle is well developed, segments of the fuel cycle are faced with a number of complex, interrelated but solvable problems which must be resolved in a timely manner to ensure that the necessary supporting functions do not impede the utilization of nuclear power. The purpose of this Appendix is to discuss the problems which face the nuclear fuel cycle.

Figure V A-1

The Light Water Reactor Nuclear Fuel Cycle



URANIUM RESERVES AND RESOURCES

As is the case with other resource estimates, there is considerable uncertainty about the total size of the domestic uranium resource base, reflecting the extent of exploration efforts. Considerable exploration for uranium was conducted in the early 1950's by the Atomic Energy Commission and the U.S. Geological Survey with a subsequent major effort by private industry. In the period 1967-69, there was a sharp increase in exploration efforts well above the levels of the 1950's, followed by decreased exploration of the early 1970's due to softening in the uranium market as a consequence of slippage in uranium demands. Starting in 1973, exploration activities increased again and are expected to continue to increase in 1976.

In its latest survey of uranium resources, the Energy Research and Development Administration has divided uranium deposits into two main categories: reserves and resources. Ore reserve estimates are the most reliable figures since they are based on drill-hole and other geologic data made available to ERDA by the uranium companies. Potential resource estimates are estimates of undefined and undiscovered resources in geologic formations in the United States, and these estimates are divided into three subcategories (probable, possible, and speculative) to reflect their degree of reliability. The reliability is greatest in the probable class where there has been extensive exploration and where mines have been developed -- thus defining local ore deposits. The reliability is least in the speculative class where area of favorability must be inferred solely from literature survey, geological reconnaissance of formation outcrops, and the examination of the logs and cuttings from wells drilled for petroleum and other purposes.

Since various grades of ore exist (average uranium ore from underground mines contained 0.22 and 0.20 percent U_3O_8 in 1974 and the first half of 1975 respectively) and since the ore occurs in deposits of varying thickness and scope and at varying depths, both resource and reserve estimates have been further categorized in terms of their "forward" costs of production. Forward costs are defined as those operating and capital costs yet to be incurred to produce a particular body of ore. They do not include profit and "sunk" costs such as past expenditures for property acquisition, exploration, and mine development. The various forward costs are independent of the market price at which the reserves and estimated resources would be sold. Table VA-1 summarizes the latest estimates of uranium reserves and resources that could be recovered at various maximum forward costs. Eash successive cost category includes the estimates of the lower cost category or categories.

Table VA-1

URANIUM ORE RESERVES AND RESOURCES*
(Thousand Tons U_3O_8)

Forward Cost	Reserves	Resources Probable	Resources Possible	Resources Speculative	Total
$ 8/lb	200	300	200	30	730
$10/lb	315	460	390	110	1275
$15/lb	420	680	640	210	1950
$30/lb	600	1140	1340	410	3490

* U.S. Energy Research and Development Administration, Statistical Data of the Uranium Industry, Grand Junction, 1975.

In addition to the resources listed in Table VA-1, U_3O_8 may be recovered as a by-product of phosphate and copper production. Also, the recent price increases for alternate fuels have opened the possibility of eventual utilization of uranium available at forward costs higher than $30/lb. The Chattanooga Shale in Tennessee has a uranium content of about 60 ppm and contains in excess of 5 million tons of U_3O_8 that would be producible perhaps at a forward cost of around $100/lb. This Chattanooga Shale, plus other low grade deposits, could yield as much as 26 million tons.

Presently known uranium reserves in the contiguous U.S. are concentrated in a few states. Major mining areas are found in Wyoming, Utah, Colorado, and New Mexico; in 1974, New Mexico and Wyoming produced 75 percent of all the U_3O_8 mined (see Table VA-2).

Table VA-2

DISTRIBUTION OF U_3O_8 PRODUCTION IN ORE BY STATES, 1974

State	Tons of Ore	Tons of U_3O_8	Percent of U_3O_8 Produced
New Mexico	2,997,000	5,400	43
Wyoming	2,458,000	4,000	32
Colorado, Texas, Utah, Washington, and other states	1,661,000	3,200	25
Total	7,116,000	12,600	100

Source: Statistical Data of the Uranium Industry, ERDA GJO-100(75), January 1, 1975.

Excluding uranium resources potentially available from abroad, the maximum nuclear capacity that can be supported based on presently available light water reactor technology will be determined by the extent of our economically and environmentally producible domestic uranium resources. Assuming 70 percent capacity utilization, from 150 to 200 short tons of U_3O_8 are needed each year to fuel a 1000 Mwe light water reactor and two to three times that amount is needed to make up a complete initial reactor core. A total of approximately 6000 tons of U_3O_8 is required to fuel a reactor for 30 years of operation.

The actual amount of U_3O_8 utilized will depend upon the operating characteristics and type of nuclear reactor, and two other important factors: the tails assay of the uranium enrichment plants and the recycling of uranium and plutonium from spent fuel. The 6000 ton figure assumes no recycling and a tails assay of 0.3 percent. By lowering the tails assay of the enrichment plant, more of the isotope U-235 is recovered from the feed stream, thereby lowering the requirement for U_3O_8. Lowering the tails assay to 0.2 percent would decrease uranium requirements by about 17 percent. Utilization of unburned uranium and plutonium from spent fuel discharged from reactors could also significantly decrease reactor uranium requirements by approximately the same percentage.

Given these assumptions, some 1.4 million short tons of U_3O_8 will be needed to support the 240,000 Mwe of nuclear capacity in operation under construction, or on order as of August, 1975, for their entire lives assuming 30 years of operation. As shown in Table VA-1, the total of reserves and probable resources at $30/lb or less, which have been counted on for planning purposes, exceeds 1.7 million short tons of U_3O_8, sufficient to fuel the 240,000 Mwe now on order or in operation and an additional 60,000 Mwe or more of capacity for 30 years of operation. Whether or not additional nuclear plants can be fueled beyond this 300,000 Mwe depends on how successful the industry is in the coming years in their uranium exploration efforts.

Continued exploration and development effort will be required to convert resources into reserves. Historically, there has not been a large incentive to explore new districts, especially since the uranium market has been quite soft. In fact, for many years the Federal Government encouraged development of the uranium industry in order to meet military requirements guaranteeing to buy uranium at a fixed price. However, conditions have recently changed uranium transactions into a sellers' market.

The uncertainties in the long-term availability of uranium have implications for the timing and planning of interrelated portions of the fuel cycle and for the need to develop new technology to replace it. To reduce uncertainty, the Energy Research and Development Administration has recently begun a large scale assessment of potential uranium sources in the continental U.S. and Alaska, which will not be finished for several years. These estimates will supplement existing information on undiscovered resources which are based almost entirely on data developed from previously productive geologic formations in the U.S.

MINING

In spite of the reduction in this year's estimates of nuclear capacity expected to be in commercial operation by 1985, U_3O_8 requirements will still have significant implications for the mining industry. In the last six years about 13,000 short tons of U_3O_8 were produced annually in this country while existing milling capacity could handle as much as 17,000 short tons. By 1985 two to three times (30,000-40,000 short tons) the current annual amount of U_3O_8 will have to be produced and delivered for conversion and processing into fuels depending on the tails assay of the enrichment plants and whether plutonium and uranium are recycled. Milling capacity will have to be expanded to meet this level of annual demand. By the late 1970's, additions and modifications to existing mills will increase industry capacity to about 23,000 tons annually.

As of January, 1975, a little over 100,000 tons of U_3O_8 had been committed for delivery by 1985 (see schedule in Figure VA-2). This figure shows that uranium producers and utilities have made very few long-term delivery commitments for U_3O_8 in spite of the fact that a nuclear plant is expected to operate for 30 years. Figure VA-3 compares delivery commitments with projected annual requirements. Clearly, not all the annual requirements to fuel new and currently operating nuclear power plants has yet been contracted for. In fact, recently Westinghouse Electric Corporation contended that it was "legally excused" from honoring its contracts to deliver uranium to some customers after 1978 for the contracted price. This action could affect the delivery of up to 40,000 short tons of U_3O_8 over a period of years for which utilities had contracts with Westinghouse.

Numerous market uncertainties have dominated the industry's thinking about future investment in uranium mining. Today the industry faces a number of market uncertainties as a result of delays in nuclear capacity additions, the incremental lifting of the ban on imports of uranium for domestic use beginning in 1977, the lack of a final decision on the plutonium recycle question, and the potential of possible local nuclear moratoria.

Uranium prices will probably serve as an incentive to continue exploration and development of domestic uranium resources. The average price for material delivered in 1974 is reported to have been \$7.90/lb. Projected prices under new contracts have increased sharply (see Figure VA-4). Since material for near term deliveries was largely under contract, the most significant impact of the higher prices in terms of cash flow and financial ability to continue exploration for new uranium deposits occurs in the late 1970's and early 1980's.

It is estimated that it takes about seven to eight years from exploration drilling to production and that it takes three years to open a mine and two years to construct a mill. Adequate incentives could probably reduce the time schedules for machinery and equipment. Capital costs for needed uranium mining and milling activities could be on the order of several billion dollars in the 1975 to 1990 period; however, the major portion of the capital will be required after 1982 or 1983.

The problems which threaten to create a shortfall of uranium supply at the end of this decade are not technical. Sufficient time exists, if proper incentives are

Figure V A-2

Domestic Uranium Delivery Commitments

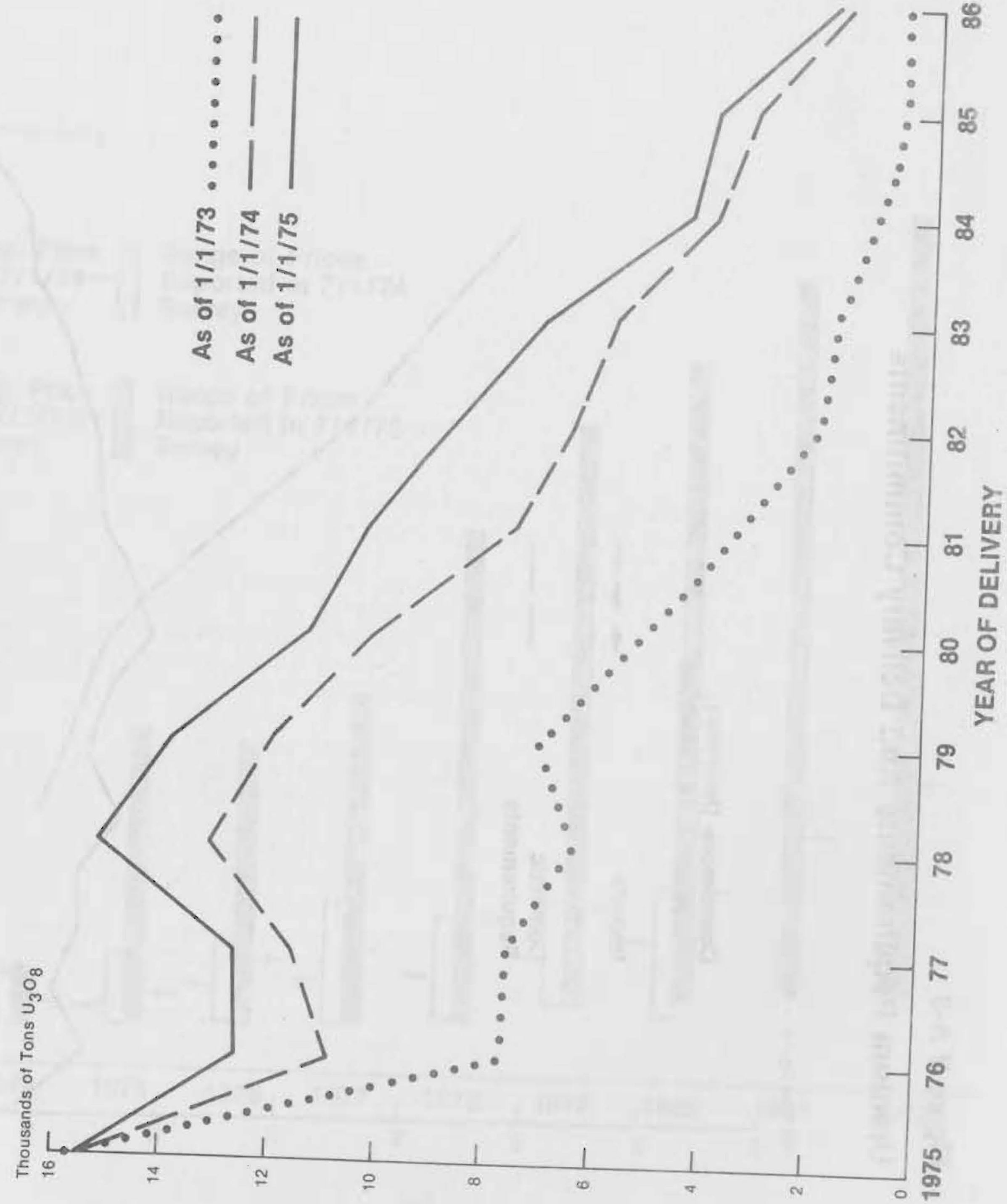


Figure V A-3

Uranium Requirements And Delivery Commitments

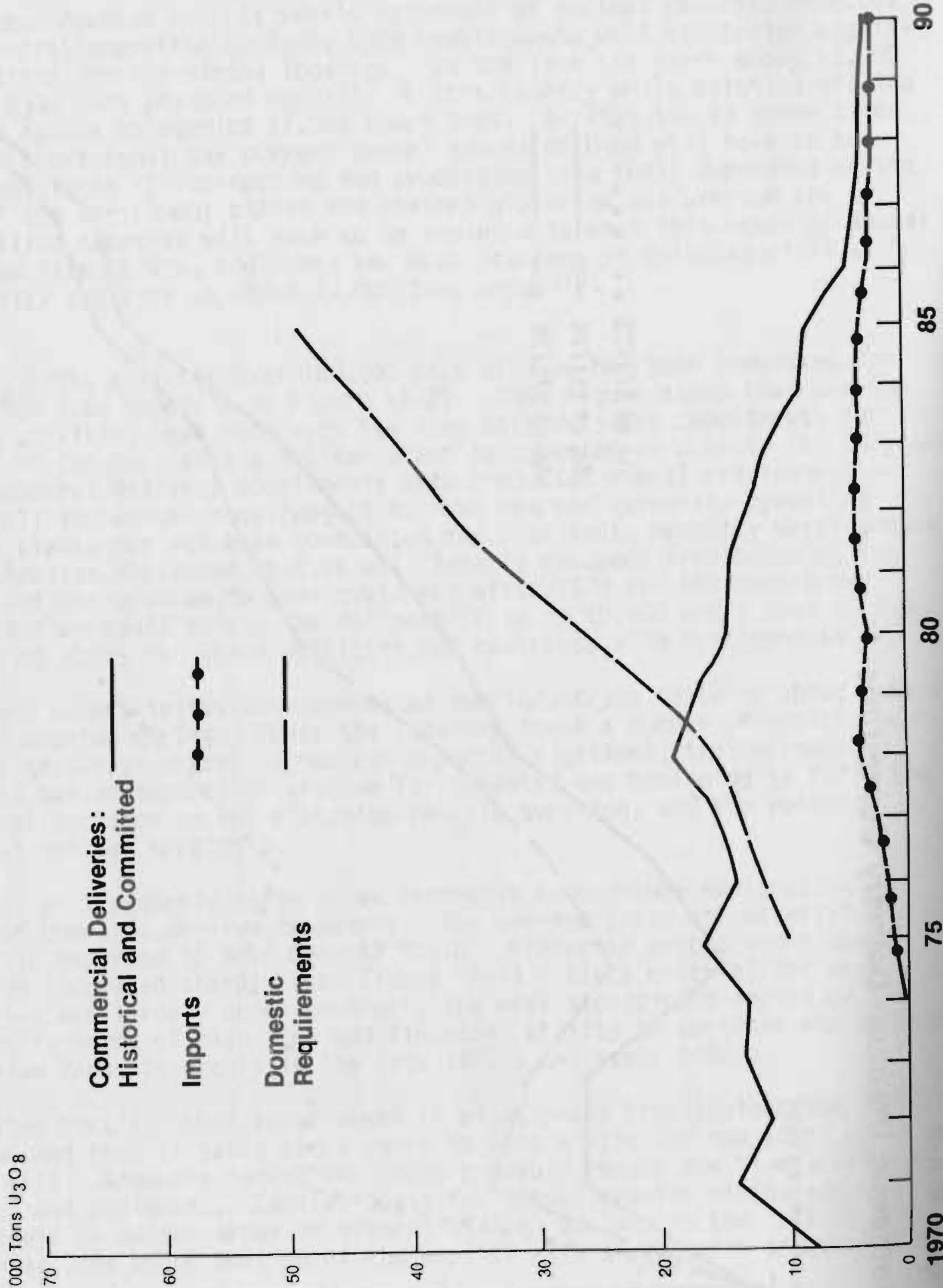
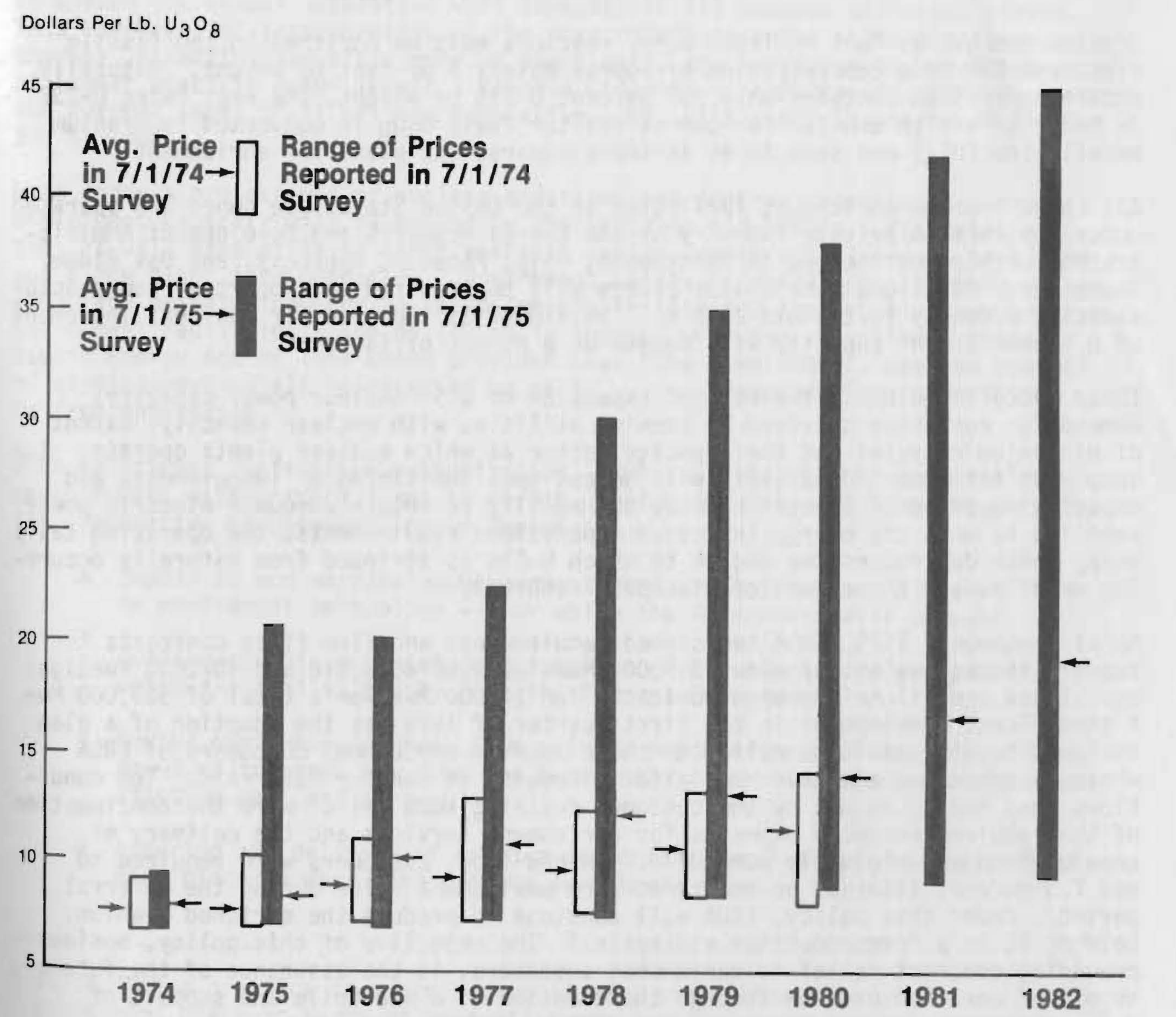


Figure V A-4

Range of Reported U_3O_8 Prices in 1974 and 1975



provided, to begin the expansion of existing mines and facilities and the development of new mines now. It is hoped that utilities and the uranium suppliers will meet their responsibilities in this area by establishing firm contractual arrangements which will both guarantee utilities uranium supplies at reasonable prices and guarantee uranium suppliers adequate future sales and revenues to permit them to invest in capacity expansions.

URANIUM ENRICHMENT SERVICES

Uranium for use as fuel in light water reactors must be enriched in the fissile isotope U-235 to a concentration of approximately 3 percent by weight. Naturally occurring uranium contains only 0.7 percent U-235 by weight, the rest being U-238. In order to enrich uranium for use as reactor fuel, U_3O_8 is converted to uranium hexafloride (UF_6) and sent to an isotopic separations plant for enrichment.

All three uranium enrichment facilities in the United States are owned and operated under contract to private industry by the Energy Research and Development Administration. They are located in Portsmouth, Ohio; Paducah, Kentucky; and Oak Ridge, Tennessee. Additional enrichment plants will be required in support of new reactor capacity probably in the mid-1980's. The timing of the need for the next increment of U.S. enrichment capacity will depend on a number of factors.

These factors include: the rate of expansion of U.S. nuclear power capacity; demand for enriching services by foreign utilities with nuclear capacity; extent of plutonium recycle; and the capacity factor at which nuclear plants operate. The supply of enrichment capability will depend upon the timing of improvements and capacity uprating of present plants, the ability to obtain adequate electric power supplies to meet the energy intensive separations requirements, the operating tails assay which determines the degree to which U-235 is stripped from naturally occurring uranium; and the extent of stockpile reserves.

As of September, 1975, ERDA had signed requirements and firm fixed contracts to support the equivalent of about 315,000 Mwe (208,000 domestic and 107,000 foreign) and signed conditional foreign contracts for 14,000 Mwe for a total of 329,000 Mwe. A significant development in the first quarter of 1975 was the adoption of a plan designed to give one-time relief to those uranium enrichment customers of ERDA whose enrichment needs have been altered because of reactor deferrals. The conditions that had to be met by the customer desiring such relief were the continuation of the required advanced payments for enrichment services and the delivery of uranium feed as originally scheduled. In addition, customers were required to pay 7.5 percent interest on the first-core enrichment value during the deferral period. Under this policy, ERDA will continue to produce the enriched uranium, holding it in a "preproduction stockpile." The objective of this policy, besides providing contract relief to enrichment customers, is the assurance of the future supply of enriched uranium through the creation of a stockpile and support of U.S. uranium mining and producing industry.

During the open season, 121 domestic customers asked for postponements averaging 23 months and 56 foreign customers asked for postponements averaging 28 months. As a result, ERDA estimates that its preproduction stockpile inventory can be

increased from 20 million separative work units (SWU) to about 35 million SWU.* The increase in the stockpile does not postpone the need for new enriching capacity but it does make possible much firmer ERDA backup guarantees should new enrichment plants have start-up problems or should production from ERDA's facilities be curtailed due to losses of power, extended plant maintenance shutdowns or other factors.

In anticipation of meeting contract commitments to supply enrichment services, the Federal Government is making a sizeable investment over the next few years to expand the annual separative work capacity in its gaseous diffusion plants. This involves the incorporation of the most recent advances in technology, thereby increasing the efficiency of the plants, and a program to permit the use of higher electric power levels. Planned capacity is expected to increase from the current level of 17 million separative work units (SWU) to nearly 28 million SWU by 1984.

With today's projections of nuclear additions and contract commitments, new enrichment capacity will be needed by the early to mid-1980's. Estimates are that it will take at least eight years to design, construct, license, test, and put a new plant into operation. Government policy since 1971 has been to encourage private industry to assume responsibility for constructing new uranium enrichment facilities. The policy is in keeping with the provisions of the Atomic Energy Act of 1954 which provided that "the development, use and control of atomic energy shall be directed so as to . . . strengthen free competition in free enterprise."

With additional legislative authorization, ERDA could enter into cooperative arrangements with private firms to enrich uranium for sale, at home and abroad. The cooperative arrangements could include:

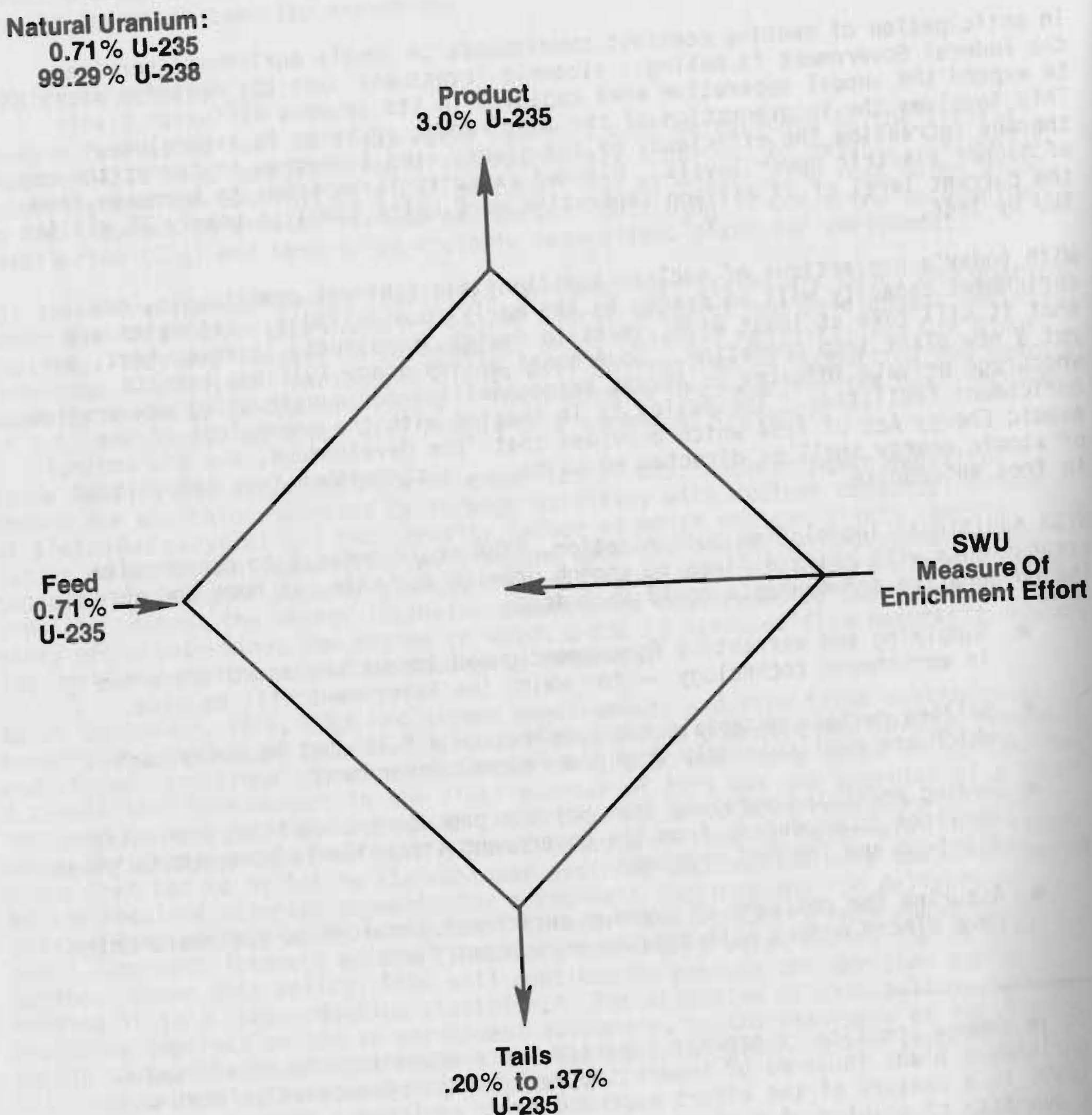
- Supplying and warranting Government-owned inventions and discoveries in enrichment technology -- for which the Government will be paid.
- Selling certain materials and supplies on a full cost recovery basis which are available only from the Federal Government.
- Buying enriching services from private producers or selling enriching services to producers from the Government stockpile to accommodate plant start-up and loading problems.
- Assuring the delivery of uranium enrichment services to customers which have placed orders with private enrichment firms.

---

* It is common practice to express capacity and production rate of a uranium enrichment plant in terms of separative work units. A separative work unit (SWU) is a measure of the effort expended in an enrichment plant to separate a quantity of uranium of a given assay into two components, one having a higher percentage of U-235 and one having a lower percentage (see Figure VA-5).

Figure V A-5

Separative Work Unit (SWU)



- Assuming the assets and liabilities (including debt) of a private uranium enrichment project if the venture threatened to fail -- at the call of the industry participants or the Government, and with compensation to domestic investors in the private ventures ranging from full reimbursement to total loss of equity interest, depending upon the circumstances leading to the threat or failure.

ERDA has recently taken the following administrative actions:

- ERDA is responding to a proposal from Uranium Enrichment Associates (UEA) which could lead to the construction of a $3.5 billion gaseous diffusion plant of 9 million SWU's capacity to come on line in 1983.

- ERDA has issued a request for proposals to build gas centrifuge enrichment capacity and has received proposals from Exxon Corporation, The Signal Companys, and a joint venture consisting of Atlantic-Richfield and Electro-Nucleonics Corporation (all plants to have about three million SWU's capacity). These proposals have been evaluated and meet the acceptability criteria established in ERDA's request for proposals. Detailed negotiations are now being initiated with these three groups which could lead to three cooperative agreements for the construction of gas centrifuge enrichment plants.

The proposals are based on two different separation techniques: gaseous diffusion and gas centrifuge.* The gaseous diffusion process is used in all three existing enrichment plants. A major advantage of gas centrifuge technology is that it uses only one-tenth of the electricity to accomplish the same amount of separation as that required by using the gaseous diffusion process. Also, plant construction lead times are shorter and capacity additions can be made in smaller increments than that required for an economic gaseous diffusion plant. However, thus far, this technology has only been applied on a demonstration scale.

The UEA-Bechtel proposal to build a gaseous diffusion plant on a 1,700 acre site near Dothan, Alabama is the farthest along, but no significant financing other than for engineering feasibility and market promotion have so far been devoted to it.

The Exxon, Signal Companys and Atlantic Richfield-Electro-Nucleonics proposals are basically for three million SWU gas centrifuge plants which have not yet

---

* The gaseous diffusion process essentially involves forcing uranium in the form of a gas (uranium hexafluoride) through a series of filters or barriers which separate U-235 from U-238 by virture of the fact that lighter isotopes diffuse through these barriers at a somewhat more rapid rate than the heavy isotopes. In the gas centrifuge method, uranium hexafluoride is spun in a centrifuge and isotopic weight differences results in the separation of U-235 from U-238.

been demonstrated on a commercial scale. Like the UEA venture, all would require cooperative arrangements with ERDA for technological support and temporary financial assurances.

SPENT FUEL REPROCESSING

The fuel cycle up to the time the fuel rods are loaded into the reactor is largely a straight forward materials handling and manufacturing operation with some environmental and radiation considerations. This is the so-called "front-end" of the nuclear fuel cycle where the major issues are: the adequacy of the resource base; the ability of industry to expand exploration and development activities and open new mines and mills; and whether sufficient new enrichment capacity will be on line to sustain future nuclear development.

Fuel discharged from light water reactors contains appreciable quantities of unburned uranium-235 and plutonium. There are alternative ways of handling these materials. The uranium and plutonium can be chemically recovered from the spent fuel and the uranium or both the uranium and plutonium in mixed oxide form can be recycled as fuel in light water reactors (see Figure VA-1). Alternatively, the spent fuel rods can be permanently stored without recovery of the unburned fissile material. The actual mode of operation of the "back end" of the fuel cycle will be a function of both economics and regulatory policy.

To conserve domestic fuel resources, spent reactor fuel can be reprocessed and plutonium and uranium oxide fuels fabricated for reuse in light water reactors. By recycling, requirements for newly mined U_3O_8 could be decreased significantly, thus conserving a limited resource. Furthermore, plutonium generated by the light water reactor system could be used to start up and sustain a new generation of so-called breeder reactors. In one form of the breeder, fissile plutonium rather than uranium, would be used for fuel and the fission process would be used to generate both heat for electricity and more plutonium than was burned by transmutation of depleted uranium tails from the enrichment process (see Figure VA-6). In this way the existing uranium resources could be extended by a factor of 60 or more.

Industry and many electric utilities have assumed that spent fuel reprocessing and mixed oxide fuel recycle will occur. In fact, industrial firms have proceeded to build some of the necessary facilities, but have run into technical and regulatory problems.

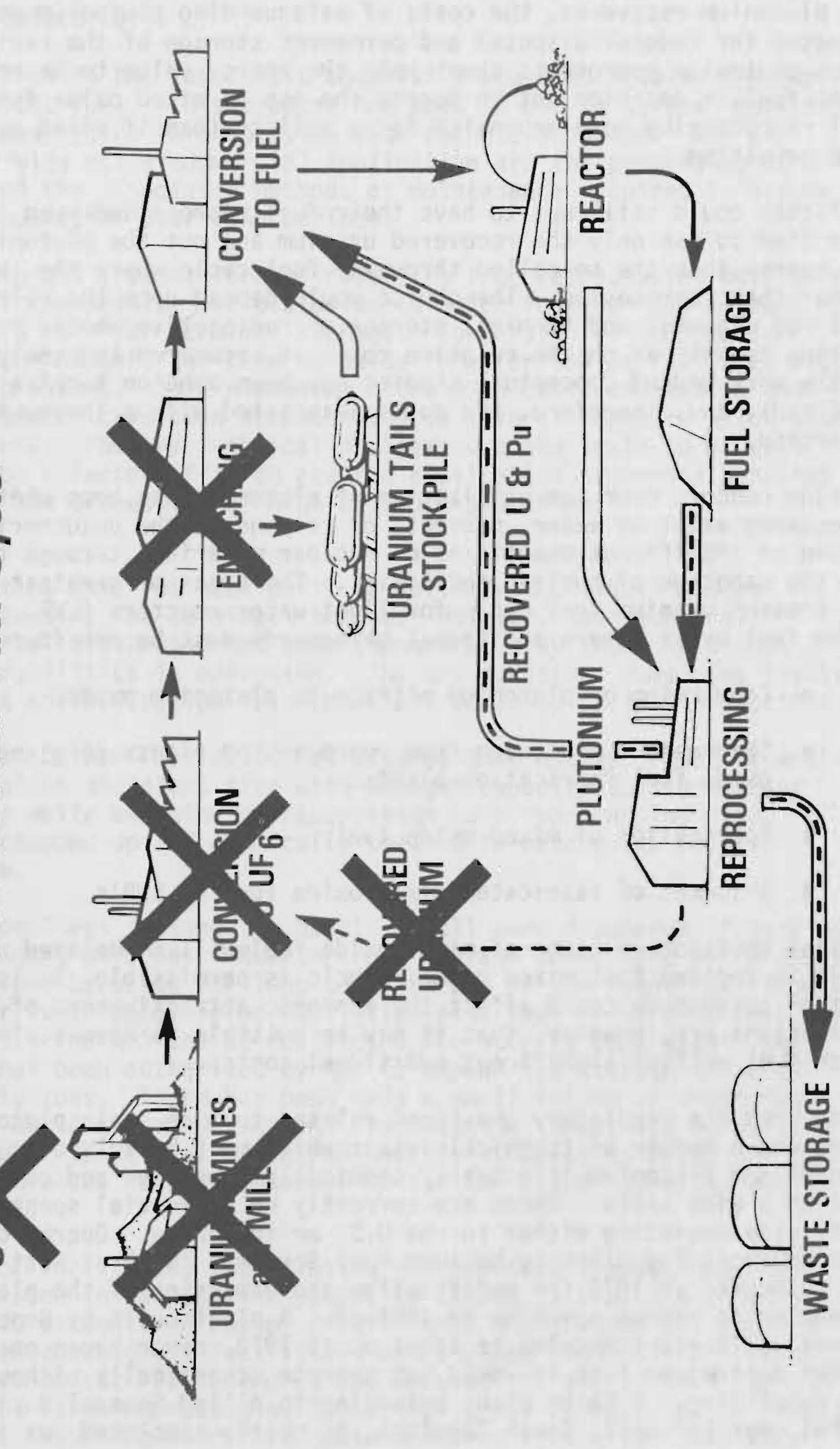
Reprocessing has been delayed by environmental questions and regulatory uncertainties with regard to the decision to permit the use of mixed oxide (plutonium and uranium) fuels. In November, 1975, the Nuclear Regulatory Commission (NRC) announced procedures for considering the wide scale use of mixed oxide reactor fuel. It proposes to license, on a interim basis where warranted, facilities which would produce mixed oxide fuel and hopes to make a final decision on the wide scale use of mixed oxide fuel for light water nuclear reactor plants in early 1977.

It is difficult to determine the economics of spent fuel reprocessing because of a number of uncertainties. These include: the capital and operating costs

Figure V A-6

Fast Breeder

The Light Water Reactor Nuclear Fuel Cycle



associated with reprocessing, the value of the uranium recovered, the value of the plutonium recovered, the costs of safeguarding plutonium and the costs to be assessed for Federal disposal and permanent storage of the radioactive wastes. Since plutonium represents about half the energy value to be recovered from spent fuel, a decision not to permit the use of mixed oxide fuel would make fuel reprocessing more expensive for a utility than if mixed oxide fuel use were permitted.

Utilities could still opt to have their fuel reprocessed even if they were permitted to use only the recovered uranium and not the plutonium. This could be cheaper than the so-called throwaway fuel cycle where the spent fuel is stored rather than reprocessed. The choice would depend upon the relative costs of spent fuel rod disposal and terminal storage of radioactive wastes resulting from reprocessing as well as on the relative costs of recovered and newly mined uranium. Little work beyond conceptual studies has been done on terminal storage of spent fuel rods, and, therefore, the costs associated with a throwaway fuel cycle are uncertain.

A major concern over the utilization of plutonium has been whether adequate safeguards exist to deter, prevent, or respond to the unauthorized possession or use of significant quantities of nuclear materials through theft or diversion and the sabotage of nuclear facilities. The areas of greatest difference between the present uranium fuel cycle for light water reactors (LWR) and the LWR mixed oxide fuel cycle, where additional safeguards must be considered are:

- Conversion of plutonium nitrate to plutonium oxide.
- Shipment of plutonium from reprocessing plants to mixed oxide fuel fabrication plants.
- Fabrication of mixed oxide fuel.
- Shipment of fabricated mixed oxide fuel to LWR's.

A final decision on usage of mixed oxide fuel will be delayed until early 1977. If it is decided that mixed oxide recycle is permissible, it is possible that the cost of safeguards could affect the economic attractiveness of using plutonium. Indications are, however, that it may be possible to adequately safeguard mixed oxide fuel without significant additional costs.

Aside from the regulatory questions related to wide-scale plutonium recycle, there are a number of technical issues which must be solved to assure that uranium and plutonium is actually chemically processed and converted to LWR fuel on a wide scale. There are currently no commercial spent fuel reprocessing facilities operating either in the U.S. or in Europe. Operation of the initial U.S. reprocessing plant by Nuclear Fuel Services (NFS) at West Valley, New York was suspended in 1971 for modification and expansion of the plant. It is scheduled to reopen sometime in 1981-82. A plant built by General Electric at Morris, Illionis scheduled to start up in 1972, never began operations because it was determined that it would not operate economically without major redesign and rebuilding. A third plant belonging to Allied General Nuclear Services (AGNS) near Barnwell, South Carolina, is nearly completed but is not expected

to begin operations before 1977.

Both NFS and AGNS are using the same basic chemcial process to recover uranium and plutonium from spent fuel. This process has been in use in several government facilities for many years in connection with defense programs. The key technical issues for wide scale commercial application are the processing of high exposure fuel and the associated methods of maintenance required to assure continuous economic operation over long periods.

In addition, the waste and product streams resulting from reprocessing must be dealt with to convert the uranium and plutonium to oxide form for use as fuel and the waste to solid form for terminal storage. Conversion of the uranium to gaseous form for enrichment, and then to oxide form for use as fuel does not present significant problems. Both plutonium nitrate to oxide conversion and plutonium fuel fabrication have been demonstrated in several industry pilot-scale fuel fabrication plants. The key technical problems are the scale-up of well developed processes by a factor of 10-20 and the application of remote handling techniques to enable the processing of high exposure plutonium.

No commercial facilities have yet been built to solidify the liquid wastes resulting from reprocessing for terminal storage. However, the technical feasibility of waste solidification has been demonstrated by ERDA, which has several pilot-scale facilities in operation. The key questions remaining involve selection of the best solidification techniques and scale-up to full production.

Past planning for the nuclear fuel cycle has assumed that nuclear reactors would have a spent fuel pool at the plant site with enought capacity to store spent fuel rods temporarily while awaiting transportation to a reprocessing plant where they would be chopped up and chemically treated in batches to recover plutonium and uranium.

The reactor storage pool was designed to handle a full core discharge if required for safety or operational purposes. Reactor fuel storage pools were not ordinarily designed with sufficient capacity for long-term storage of the spent fuel from the reactor. The nuclear fuel reprocessing facilities also have or were to have spent fuel storage capacity. The NFS and GE facilities are storing some spent fuel, and the GE facility has been authorized by NRC to expand its storage capacity from 100 to 750 metric tons. There has been only a small volume of spent fuel discharged to date. While the recycling and reprocessing issues are being resolved, the problem of spent fuel discharge and its disposal is beginning to grow as the volume increases as a consequence of nuclear plant operation and new capacity additions.

In a number of reactor facilities, the existing reactor pool storage capacity can be expanded. In some instances, the potential exists to expand storage capacity by 200 to 300 percent. A number of utilities have expressed interest in expanding their reactor storage facilities, and a number have already submitted applications to NRC to do so. Furthermore, the possibility exists that storage space available at the three reprocessing facilities could be expanded to handle additional spent fuel rods. However, all these measures will offer only very limited short-term relief to utilities for their spent fuel rod disposal problem.

LONG-TERM WASTE STORAGE

ERDA is responsible for the long-term management of commercial high-level radioactive waste and for other commercial waste which might be identified by Federal regulations as requiring Federal custody. ERDA requirements on waste handling obligate the commercial processor to convert the high level waste solution to a stable solid (the precise composition of which is still unspecified) and to seal the solid material in high integrity canisters of manageable size before transferring the material to a Federal repository. This requirement assumes that spent fuel will actually be reprocessed. In view of the present uncertainty on the processing issue, the question of the management of commercial waste and its ultimate storage is not completely resolved. If reprocessing does not occur, the spent-fuel rods themselves will have to be stored rather than some solidified form of the aqueous wastes resulting from the chemical process necessary to separate uranium and plutonium from the spent fuel.

Permanent underground storage in a stable geologic zone is considered to be the most attractive final means of storage to take care of high level radioactive waste. The search for such acceptable sites is continuing, and once an underground location is chosen, tests will be conducted to determine if the means and location of storage is environmentally acceptable.

Clearly, long-term waste storage remains a significant issue in nuclear development. With the slippage in nuclear capacity additions and the delay in the decision to permit mixed oxide fuel use, the pressure for an immediate resolution of the storage question has been slightly alleviated but remains an urgent problem. Technical and practical problems as to the best method of terminal storage must be resolved to assure that high-level waste generated in the future can be taken care of and to reduce the criticism and apprehension created by uncertainties about this end of the fuel cycle.

SUMMARY

The development of the nuclear fuel cycle industry is essential to the expansion of nuclear power. A number of technical and other issues related to the fuel cycle remain unresolved. These issues must be addressed soon, and satisfactorily resolved, so that they do not become obstacles to further nuclear development. This is particularly true for the so-called "back-end" of the fuel cycle.

Nuclear reactor generated electricity contributes to U.S. energy independence only to the extent that there are abundant domestic reserves and resources of uranium ore, the basic input to nuclear fuel. While there is some uncertainty as to the size of the uranium resource base for the long term, ERDA has an extensive program underway to locate the new uranium resources which will be needed if the use of light water reactors is to continue expansion to the turn of the century and beyond. In the near term, reserves are sufficient and domestic uranium producers must expand and develop new mines and milling capacity to meet future uranium requirements. Timely investment in additional mining and milling capacity has been hampered by uncertainties about future demand, ore prices, and a shortage of capital. Resolution of regulatory uncertainties, different contracting arrangements between producers and users of uranium, and

greater certainty about future requirements should lead to the needed investment in exploration and facilities.

Current government owned enrichment facilities can support about 315,000 Mwe assuming fuel reprocessing and plutonium recycle. Fixed contracts for 208,000 Mwe domestic and 107,000 Mwe foreign have been signed by ERDA. In order to permit orderly development of the LWR industry regardless of whether or not plutonium recycle is permitted, and to preserve the market position of the U.S. in world nuclear development, additional new enrichment capacity will be needed in the mid-1980's. Current plans are to meet this need through private sector construction of a new nine million SWU gaseous diffusion plant to be on line in the mid-1980's and with increments of three million SWU centrifuge plants as required by projected demands for later years.

Spent fuel reprocessing is dependent upon: 1) a favorable ruling from the Nuclear Regulatory Commission on the wide scale use of plutonium for fuel, 2) on the decision by utilities that it is economic to recover just the uranium from spent fuel in the event that plutonium use in LWR's is prohibited and, 3) on the resolution of a number of technical issues associated with reprocessing and fuel fabrication. Until the questions are resolved, the industry cannot plan with confidence. Currently, it is estimated that the earliest that spent fuel reprocessing can begin is in 1977. There may be delays beyond this date such that nuclear power plants will have to expand their spent fuel storage pools to accommodate several years of spent fuel discharges. Most spent fuel storage pools appear to be capable of significant expansion.

Because of slippages in nuclear power plant and spent fuel reprocessing schedules, the onset of high volumes of radioactive waste has been postponed a few years. This should give NRC and ERDA time to develop acceptable standards for the delivery of aqueous wastes in solidified form and to choose appropriate geologic locations for terminal storage. This does not postpone the urgent need to resolve these problems to assure the public that adequate provisions have been made for terminal radioactive waste storage.

If plutonium recycle in light water reactors is not permitted and if utilities decide to have their fuel reprocessed to recover just uranium from spent fuel, then provisions will have to be made to store both high level wastes and plutonium for possible later use in breeder reactors. If neither recycle nor reprocessing take place, then terminal storage plans will have to be made for spent fuel rods.

Appendix V-B

FINANCIAL SITUATION OF THE INVESTOR-OWNED ELECTRIC UTILITIES

INTRODUCTION

The financial problems currently facing the investor-owned electric utilities have developed slowly over the past decade. This Appendix reviews the major historical trends that have converged to make this industry both highly dependent on external financing and increasingly less able to compete for such financing.

The starting point for analysis is the basic structure of electric utility balance sheets and pricing structures. These two elements are directly related through the practice of regulating utility prices to provide an allowed return on invested capital. This procedure requires that the regulatory commissions set strict definitions of the assets to be included in the rate base and the costs allowable against revenues.

The aspects of rate base definition that are relevant to this analysis are the inclusion, or exclusion of construction work in progress (CWIP), in the rate base, the common accounting practice of crediting an allowance for the use of funds during construction (AFDC) to income, and the depreciation of rate base assets over long periods for rate making purposes.

In a steady-state system with stable prices and relatively short construction lead times, current accounting practices would satisfy the regulatory objectives. CWIP would represent a relatively small part of total assets, while AFDC, a non-cash credit to income, would not represent a large portion of reported earnings, and depreciation would provide a reasonable cash flow for new construction. During the 1960's when these conditions were approximated with the exception that the system was growing rapidly, the industry was able to finance 40 to 50 percent of its new plants from internal sources, matching the general pattern for most of industry. By 1970, however, the percentage provided by internal funds had dropped to 27 percent where it has remained since (see Table VB-1).

Table VB-1

PLANT EXPENDITURES AND INTERNALLY GENERATED FUNDS OF ELECTRIC UTILITIES
($ Million)

Year	Cash Expenditures Plant	Internally Generated Funds	Percent Internally Generated
1965	4,333	2,456	56.7
1966	5,284	2,565	48.5
1967	6,517	2,664	40.9
1968	7,177	2,687	37.4
1969	8,294	2,835	34.2
1970	9,987	2,878	28.8
1971	11,632	3,105	26.7
1972	12,713	3,490	27.5
1973	14,038	3,903	27.8
1974	15,214	4,205	27.0

Source: Edison Electric Institute.

INTERNAL FINANCING

In the past few years there has been a rapid escalation of the cost of new plants which has substantially increased the rate of growth of utility capital spending. This cost escalation has been accompanied by lengthening of the construction period which has increased the share of reported earnings attributable to AFDC. The result has been that the need for funds has grown much faster than revenues and reported earnings (see Table VB-2). While revenues have not quite tripled, capital expenditures have almost quadrupled.

Table VB-2

GROWTH IN REVENUES AND EXPENDITURES OF INVESTOR-OWNED ELECTRIC UTILITIES
($ Million)

Year	Revenues	Reported Earnings	Cash Expenditures for Plant	Ratio of Expenditures to Reported Earnings
1965	15,404	2,558	4,333	1.70
1966	16,467	2,718	5,284	1.94
1967	17,386	2,875	6,517	2.27
1968	18,800	2,960	7,177	2.42
1969	20,324	3,130	8,294	2.65
1970	22,276	3,333	9,987	3.00
1971	25,053	3,774	11,632	3.08
1972	28,437	4,356	12,713	2.92
1973	31,848	4,851	14,038	2.89
1974	40,096	5,146	15,214	2.96

Source: Edison Electric Institute

Internally generated funds flow from three principal sources: retained earnings excluding AFDC, depreciation and amortization, and provisions for deferred or future income taxes. Of the three, depreciation and amortization have traditionally been the most important, now providing nearly all of the total internal funds flow. Retained earnings used to be the second most important source, but the growing importance of AFDC which provides no cash to pay for investment expenditures has increasingly cancelled out this source.

The practice of crediting AFDC to earnings is, in reality, a means of reporting future earnings in the current year. The cash is not received until the utility begins to amortize the AFDC after the plant begins operation, often 8-10 years after the credit to income. By 1974, no funds were provided from reported earnings less dividends and AFDC. Deferred income taxes have increased in importance concurrently with the decline in cash earnings and now provide the only steady major source of funds after depreciation. However, total Federal income tax paid by the industry declined to $563 million in 1974 so that this source is reaching its limit.

Utilities depreciate most plant over 30 to 40 years, but the Internal Revenue Service allows a life for asset depreciation purposes of 16 years for nuclear and 22.5 years for non-nuclear facilities. This favorable depreciation rate is one of the fastest growing sources of funds for the utilities. The effect of the difference in treatment of depreciation is to reduce earnings for tax purposes relative to earnings reported to shareholders, and as a result, a large part of the industry tax bill is deferred until late in the working life of the plants.

AFDC and CWIP

Retained earnings could be restored to their original importance as a source of funds if AFDC were to be eliminated. If construction work in progress (CWIP) were included in the rate base as it is incurred, the utility would be permitted to charge current customers for the financing of expenditures during construction. Using the former approach, rates are not raised until completion of the plant. Rates are then increased to cover the amortization of accumulated interest, as well as actual plant costs. In actual practice a regulatory authority adopts, on an ad hoc basis, one or the other or both of these practices.

Inclusion of CWIP in the rate base without an AFDC provision provides for a cash return to the utility on the funds invested in new plant. No abrupt increase in rates occurs on project completion, rather there is a gradual increase as funds are expended on new plant. This practice charges present consumers for the assurance of a continuing supply of electricity as well as for power consumed. It also reduces the stated cost of plants since accumulated AFDC is never added to the rate base.

Since granting an AFDC credit provides no immediate return on construction costs, the practice was equitable to electric utilities and their customers when project construction times are short, interest rates low, and project construction costs low relative to the rate base. Current project lead times and costs, however, including financing costs, have drastically increased the amounts involved: AFDC charges can amount to 20-25 percent of plant cost.

AFDC has therefore become increasingly significant as plant costs have accelerated. Since AFDC represents, in effect, a procedure for reporting future earnings in the current year, it can seriously distort the true position of the business if it becomes a major item. Under current practice dividends have been paid out of reported earnings, including AFDC. As AFDC has become increasingly significant, cash earnings retained in the business after dividend payments have consequently declined. By 1974 the amount of AFDC had risen to the point that reported earnings less dividends and AFDC had become negative (see Table VB-3).

Table VB-3

INTERNALLY GENERATED FUNDS OF INVESTOR-OWNED ELECTRIC UTILITIES
($ Million)

Year	Depreciation and Amortization	Reported Less Dividends	Less AFDC	Cash Earnings	Deferred or Future Income Tax	Total Internal Funds
1965	1,683	814	(94)	720	53	2,456
1966	1,782	861	(129)	732	51	2,565
1967	1,902	893	(189)	704	58	2,664
1968	2,044	843	(275)	568	75	2,687
1969	2,206	943	(405)	534	95	2,835
1970	2,411	950	(594)	356	111	2,878
1971	2,639	1,090	(822)	268	198	3,105
1972	2,920	1,319	(1,095)	224	346	3,490
1973	3,270	1,427	(1,297)	130	503	3,903
1974	3,638	1,328	(1,596)	(268)	835	4,205

Source: Edison Electric Institute

The increasing cost of new plants and the lengthening of the lead times for plant construction has had a serious effect on the balance sheet of the companies as well. By year end 1974, the total of CWIP was estimated at $22.5 billion, almost 18 percent of the reported net plant for the industry. This amount now exceeds one year's total investment expenditures, and represents non-earning assets.

SOURCES OF EXTERNAL FUNDS

As a consequence of the convergence of these forces, the industry has had to rely increasingly on external financing. External funds rose from 35 percent of total sources of funds for investor-owned electric utilities in 1965 to 70 percent in 1974. However, as debt ratios began to climb in the late 1960's, the industry began to switch to equity. The proportion of common stock and preferred stock rose in the 1970's. From 1965 through 1973, the electric utilities were able to expand the volume of new common stock sold each year. One of the main reasons was the steadiness of dividend payments on which many investors relied for income. However, as interest rates have risen, the yield required has forced stock prices down. For the past two years, utility common stocks have sold below book value on average. Large sales of common stock at less than book value reduce the value of shares already outstanding. As the prices declined in 1974, common stock offerings declined to $1.9 billion. As the market recovered in 1975, however, offerings rose to a record $3.4 billion (see Table VB-4).

Table VB-4

CONSTRUCTION EXPENDITURES AND EXTERNAL FINANCING BY INVESTOR-OWNED ELECTRIC UTILITIES
($ Millions)

Year	Cash Expenditures for Plant	Net New External Financing: Debt	Preferred	Common	Total	Long-Term Financing as Percent of Construction
1965	4,333	1,191	151	103	1,446	33.4
1966	5,284	2,318	252	148	2,718	51.4
1967	6,517	2,598	453	185	3,236	49.7
1968	7,177	2,990	461	326	3,777	52.6
1969	8,294	3,727	373	744	4,844	58.4
1970	9,987	5,460	1,015	1,411	7,886	79.0
1971	11,632	5,234	1,602	2,063	8,899	76.5
1972	12,713	4,312	2,104	2,252	8,668	68.2
1973	14,038	4,866	1,539	2,548	8,953	63.8
1974	15,214	7,772	1,743	1,943	11,458	75.3
1975	13,800E	6,494	2,101	3,374	11,969	86.7

E = estimated.

In recent years, as utilities began to encounter difficulties selling long-term bonds, they have relied more on temporary accommodations. Short-term debt has risen from about 3.2 percent of total capitalization in 1971 to 5.7 percent in 1974, with commercial banks supplying a large share of these loans.

If electric utilities were to continue their construction programs they had no alternative other than to continue to go to the capital market for funds. Consequently, they had to offer what the market demanded--a sizeable interest premium. In March 1974, for example, new issues of Baa utility bonds were yielding 110 basis points more than long-term U. S. Government bonds. After Consolidated Edison omitted its dividend in April 1974, the interest rate differential rose to about 375 basis points in September 1974. The yield spread has narrowed since, and was 326 basis points at year end 1975. While industrial corporations also suffered to some extent in the shift into safer securities, the penalty was far smaller than that paid by electric utilities.

The Impact of Utilities' External Financing Demands on the Capital Market

The investor-owned electric utility industry is a significant factor in the nation's capital markets and in the overall process of capital formation, because of the industry's high degree of capital intensity plus its reliance on external financing for the major part of its capital expansion. Over the past 25 years, the percentage of all personal savings absorbed by sales of electric utility stocks and bonds has steadily risen from 5 to 16 percent.

Another measure of the importance of electric utilities in the nation's capital formation is the share of investor-owned electric utility expenditures in the total capital expenditures of all U. S. industries. Over the past decade, investor-owned electric companies have doubled their proportion of the annual outlays for new plant and equipment in the United States, from 7.9 percent in 1964 to about 14 percent in recent years (see Table VB-5). Undoubtedly, some of this increase has been due to the rapid rise in the cost of construction, an important factor in utility capital expenditures. Also, growing commitments to nuclear power, a very capital-intensive form of power generation, have accounted for some of this increase. The nature of the generating plants themselves has changed as increasing amounts of safety and environmental control equipment have been added.

Table VB-5

CAPITAL OUTLAYS IN ELECTRIC UTILITIES AND OTHER INDUSTRIES

Year	All U.S. Industries ($ Billion)	Investor-Owned Electric Utilities* ($ Billion)	Investor-Owned Utilities as Percent of Total U.S. Industry (%)
1965	54.5	4.3	7.9
1966	63.5	5.3	8.3
1967	65.8	6.5	9.9
1968	67.8	7.2	10.6
1969	75.6	8.3	11.0
1970	79.7	10.0	12.5
1971	81.2	11.6	14.3
1972	88.4	12.7	14.4
1973	99.7	14.0	14.0
1974	112.4	15.2	13.5

* Electric Utility plant only.

Sources: U. S. Department of Commerce, Edison Electric Institute.

In order to satisfy these capital requirements, the electric utility industry has been increasing its share of U. S. long term financing. In the ten years from 1965 through 1974, the industry's share of the dollar value to total new long term debt and total new preferred stock have almost tripled, while its share of total new common stock has increased from 7 percent in 1965 to 51 percent in 1974 (see Table VB-6).

Table VB-6

ELECTRIC UTILITY LONG TERM FINANCING
AS PERCENT OF TOTAL FOR ALL U. S. INDUSTRIES
(Percent)

Year	Long Term Debt	Preferred Stock	Common Stock
1965	10	29	7
1966	15	44	8
1967	12	51	9
1968	18	72	8
1969	20	56	10
1970	19	83	19
1971	17	50	22
1972	15	75	24
1973	23	55	33
1974	27	77	51

Source: Edison Electric Institute, Federal Reserve Board

Long-Term Debt

Increased equity financing has thus far had very little effect on the overall capital structure of the utility industry. While preferred stock has increased in significance in the utilities balance sheet, the most striking fact is the remarkable stability in the industry's capital structure. In fact, the debt-equity ratio has remained essentially constant at 60/40.

This period of expanding utility financing has also been marked by a rapid rise in general interest rates. In 1965 the average yield on new utility bonds was 4.6 percent; by 1970 it had risen to 8.8 percent and continued to 9.7 percent in 1974. This concurrent rise in capital requirements and interest rates has produced a rate of increase in debt service charges exceeding the growth of electric utility earnings. This, in turn, has led to a steady decline in the ratio of earnings to interest, and for many companies this key index has fallen to the minimum level permitted by indenture restrictions and has effectively arrested the issuance of additional debt.

Since 1967, the bond ratings of securities of approximately 70 major investor-owned electric power companies have been reduced. During 1974 alone, the ratings of at least 43 such securities were lowered. In recent months, annual interest rates on bonds rated Baa have been about two percentage points higher than those on Aaa rated securities, a fact which emphasizes the cost associated with a lower rating. A year ago this differential rose to more than four percentage points. Considering the magnitude of current electric utility offerings, such a spread in interest or dividend rates adds substantial

amounts to a firm's financing costs. Moreover, when ratings drop below single-A, available buyers shrink to a point where the ability to market large issues becomes doubtful.

In the main, the reductions in electric utility credit ratings have resulted from reductions in fixed charge coverage ratios. Most electric utility mortgage indentures require the company to maintain a specified minimum ratio of pretax operating earnings to interest charges. As this ratio declines toward the specified minimum (usually two times on a pretax basis) additional debt financing becomes increasingly difficult. In addition, the utility's bond rating is likely to be reduced which means an increase in the interest cost of new debt and further aggravation of the coverage problem. For the electric utility industry as a whole, the coverage of interest charges has declined steadily since 1965 (see Table VB-7).

In 223 electric utility rate cases settled during the three-year period 1971-1973, 212 or 95 percent, of the utilities had indentures which specified that interest payments must be covered at least 200 percent by earnings before interest and income taxes. Based on the 202 cases where data were available, a greater proportion of the earlier cases reported higher coverage ratios than did the more recent cases. In the period January 1, 1971-March 31, 1972, 62 percent of the utilities reported an interest coverage ratio of 2.5 or more. By 1973, only 44 percent were in that category.

Despite this decline in interest coverage, utilities shifted financing pattern away from equity in 1974. The reasons are complex.

Concern over declining electric utility earnings had been coupled with an overall disenchantment with stocks; these forces were driving the prices of electric utility stocks to new lows. At year end 1974, the market value of most electric utility common stocks was well below book value. When large amounts of new stock must be marketed at substantial discounts below book value, the value of the existing stock is diluted. Such dilution of equity is not in the best interests of existing stockholders. Nor are new investors likely to be interested in the stock unless they can see an immediate probability for a recovery in price to book value, particularly when it is clear that the issuance of more new stock will be necessary to maintain construction plans.

During 1974, the stock market declined and interest rates rose. These trends combined to push utility stock prices down so that by June, 1974 the average utility stock was selling at .67 times book value. As a result, there was a drop in new issues of common stock by utilities, from $2.5 billion in 1973 to $1.9 billion in 1974, despite the fact the utility offerings in 1974 accounted for half of all equity sales, up from one-third in 1973. However, as utility prices recovered in 1975, the volume of new issues rose to $3.4 billion. By year end the average stock was selling at .95 book value.

Table VB-7

DEBT AND PREFERRED COVERAGE RATIOS
INVESTOR-OWNED UTILITIES
($ Millions)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Operating Income	3,426	3,664	3,917	4,124	4,497	4,902	5,423	6,133	6,897	7,688
Income Taxes	1,683	1,746	1,734	1,914	1,845	1,461	1,434	1,629	1,721	1,666
Income Available to Service Debt	5,109	5,410	5,651	6,038	6,342	6,363	6,857	7,762	8,618	9,354
Interest Charges	992	1,103	1,262	1,494	1,823	2,270	2,650	3,048	3,642	4,615
Interest Coverage	5.15	4.90	4.48	4.04	3.48	2.80	2.59	2.55	2.37	2.03
Income Available for Preferred Dividends	2,434	2,561	2,655	2,630	2,674	2,632	2,773	3,085	3,255	3,073
Preferred Dividends	216	228	245	279	307	361	493	635	768	953
Preferred Coverage	11.27	11.23	10.84	9.43	8.71	7.29	5.62	4.86	4.24	3.22

Since September 1974, the general decline in interest rates has eased overall pressures in the capital market somewhat. Investors remain extremely risk-conscious, however. This is especially true in the case of lower-rated corporate issues. For example, at the end of December 1975, Baa public utility bonds were yielding 326 basis points more than U. S. Government bonds, while Aaa utilities carried a premium of 91 basis points. Because they remain so heavily dependent on the public market for the sale of their bonds, a particularly heavy penalty was still being imposed on public utilities.

Under such conditions, as utilities approach their borrowing limit due to falling coverage ratios and lowered credit ratings reflected in narrower markets and higher interest premiums, only improved earnings can enhance their capacity to tap long-term investment funds. To the extent that the companies can issue debt only to the limit imposed by the requirement to maintain a minimum coverage ratio, small gains in revenues can result in relatively large increases in debt carrying capacity. In theory an increase in revenues of $100 would permit the additional payment of $50 in interest which would service $500 of debt at a 10 percent rate. In practice, a company that persistently maintains minimum interest coverage will have difficulty in raising substantial amounts of debt. In either case it is clear that the industry overall is near its limit of debt carrying capacity in the face of high interest rates and increased uncertainty.

Debt Refunding

A final problem which faces utilities in managing their capital structure is the fact that several billion dollars of low coupon debt issues are maturing in the near future and must be refinanced at higher rates. Replacement of this debt at current rates will increase interest costs and place additional financial burdens on the firms involved. Unless income increases proportionately, such refundings will cause coverage ratios to decline even further.

For example, in 1975 utilities had $2.4 billion of bonds becoming due, carrying a weighted average interest rate of 5.5 percent-meaning an aggregate interest cost of $133 million. These bonds had to be refinanced at an interest cost of about 9 percnet. This would imply an increase in annual interest cost of $86 million (see Table VB-8).

Table VB-8

EFFECT OF BOND REFUNDING REQUIREMENTS ON INTEREST COSTS TO INVESTOR-OWNED ELECTRIC UTILITY COMPANIES
($ Million)

	1975	1976	1977	1978
Maturities	2,430	1,485	1,654	1,425
Average Interest Rate	5.48%	5.24%	4.51%	4.58%
Interest Costs	133.2	77.8	74.6	65.3
New Interest Costs*	218.7	133.7	148.9	128.3
Difference	85.5	55.9	74.3	63.0

* Assuming 9 percent coupon rate.

Preferred Stock

To alleviate the interest coverage problem, many electric power companies began to swing heavily into equity financing in 1969-70, emphasizing preferred stock because of what at the time seemed a relatively poor market for common stock. Since 1971, electric utility preferred stock financing has been running at about $1.6 billion annually, against only $150 million in 1966, and the preferred stock ratio to total assets rose from 8 percent in 1969 to 10 percent of assets in 1974. Once regarded as the most expensive form of financing (in terms of cash payout) because dividend costs are not tax-deductible to the issuing firm, new preferred stock issues which offer tax advantages to investing corporations can now be sold at yields within a percentage point of those of common stocks.

Preferred dividend coverage ratios have fallen at a much faster rate than interest coverage ratios (see Table VB-7). In 1965, the average preferred dividend coverage ratio was 11.27 but by 1974, this ratio had fallen to 3.22. For this reason, utilities are now approaching the limit on the quantity of preferred they can issue. Preferred stocks now face lower credit ratings as well as debt securities.

Common Stock

Thus, marketing of common stock has become the safety valve in utility financing. Sales of new common stock have averaged over $2 billion annually since 1970, reaching almost $3.4 billion in 1975.

The placement of new utility equities became more difficult in light of the declining rates of return over the past 10 years. From 1965 through 1974, investors in the electric utilities averaged a 1.7 percent combined annual yield including dividends and capital appreciation or depreciation. This

compares with a 5.18 percent average annual yield on the New York Composite Stock Exchange Index over the same period. Utility combined returns have varied greatly over the period, and in some years--1971, for example, when the utility averages rose, investors have earned handsome returns. Yet, the fact remains that utility equities have yielded less than Treasury Bills which averaged 5.7 percent over the 1965-1974 period (see Table VB-9).

Table VB-9

COMBINED RETURNS OF UTILITY EQUITIES
(Percent)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Returns on Investor-owned Electrics	2	(5)	5	7	(2)	(18)	39	2	3	(24)
Returns on the NYSE Index	11	(9)	19	12	2	(13)	22	14	(2)	(20)
Yield on One Year Treasury Bills	4	5	5	5	7	6	5	5	7	8

( ) - Indicates negative

Although institutional investors own one-third of the total market value of all corporate stocks, current estimates are that they now own only 10 to 20 percent of utility equities. The remainder is held by individual investors. Only by providing assured competitive returns to holders of utility equities can new issues be successfully marketed.

Actual and Allowed Rate of Return

Interest coverage, preferred dividend coverage, and common earnings all depend on the rate of return earned on total capital. This rate, in conjunction with the capitalization ratios determines the rate of return on equity. Historically, the actual rate of return has been different from the return allowed in rate proceedings. During the 1950's and early 1960's when falling unit costs and regulatory delays worked to the financial advantage of the utilities, the rate of return on total utility capital was well above the allowed rate of return. The actual rate of return increased throughout the 1950's and 1960's, peaking at 12.7 percent in 1967.

The decline in the actual rate of return since the late 1960's was due to a combination of increasing unit costs and regulatory delays. This decline occurred in spite of regulatory commission attempts to provide a higher rate of return.

Required Rate of Return

The electric utility industry, as the Nation's most capital intensive industry, has very large capital requirements to meet its service demands. Capital investment of almost $4 is needed to produce $1 of annual revenue (sales). By contrast, the average manufacturing company needs only $.75 to produce a dollar of annual sales. Even the more capital intensive industrial groups need considerably less capital to generate a dollar of sales: telephone companies need about $2.75; aluminum companies need $1.30 on average, and petroleum companies need only about $1.

As a result of this capital intensiveness, the capital charges paid to finance required investment play an important part in determining the ultimate price electric utilities must charge for their product. Other fixed charges such as depreciation, insurance, and property taxes, weigh heavily in the total cost of delivered energy. Historically, these annual fixed capital charges have averaged around 14 percent of total utility assets, and comprise 51 percent of total revenues. Changes in these costs imply changes in the required rate of return, defined as the return that regulatory authorities should allow to enable utilities to recover their capital costs.

One of the accepted methods for determining the required return to capital is described by Myron Gordon.* His work defines the minimum return on capital required by a utility if it is to continue to raise capital to meets its expansion needs.

The first step in determining the required return is estimating the cost of equity capital. Following the Gordon Model, this is estimated by the following equation:

$$K_e = \frac{D}{P} + g.$$

Where K_e is the Cost of Equity
D is the Common Dividend
P the Selling Price of common stock
and g the Expected Growth Rate of Dividends

It is easy to measure D/P, as this is the dividend yield associated with the purchase of utility stocks. However, the measurement of g can present serious difficulties.

Gordon estimates this variable in the following manner:

$$g = rb + vs,$$

---

* Gordon, Myron J., The Cost of Capital to a Public Utility, Michigan State University, School of Business, Ann Arbor, Michigan, 1974.

Table VB-10

ESTIMATED COST OF COMMON EQUITY
TO INVESTOR OWNED ELECTRIC UTILITIES
(Percent)

	Cost of Equity Capital	Dividend Yield*	Est. Growth in Dividends	Retention Growth	Rate of Ret. on Equity**	Retention Rate	Stock Finan-cing Growth	1-Book Market ***	Growth in Common Equity****
1974	11.53	10.52	1.01	3.71	10.9	34	-2.7	-33	8.29
1973	10.49	6.86	3.73	4.03	11.5	35	-3.0	-4	8.47
1972	11.16	6.46	4.70	4.10	11.7	35	.6	7	8.66
1971	10.16	5.63	4.53	3.83	11.6	33	.7	9	8.03
1970	11.91	6.83	5.08	3.78	11.8	32	1.3	18	7.20
1969	11.01	4.88	6.13	4.03	12.2	33	2.1	35	6.06
1968	10.49	4.48	6.01	3.81	12.3	31	2.2	40	5.40
1967	10.37	4.35	6.02	4.32	12.7	34	1.7	42	4.00
1966	9.85	4.10	5.75	4.35	12.7	35	1.4	48	3.00

Note: * As of June each year.
** Smoothed by the equation $r = \frac{\text{Earning Available for Common}}{\frac{1}{2}\,(\text{Common Equity (T)} + \text{Common Equity (T-1)})}$
*** Smoothed by the equation $\text{Rate} = 1 - \frac{(\text{Common Equity(T)} + \text{Common Equity(T-1)})}{.9\ (\text{Market Value(T)} + \text{Market Value(t-1)})}$
**** Smoothed by the following equations: Rate = Growth Rate in Total Assets - Retention Growth ; Growth Rate in Total Assets = Trend of Actual Growth Rate 1966-72, 12.5% in 1973 and 12% in 1974.

Where the term "rb" denotes the growth in dividends due to the retention in earnings which is estimated by the product of "r", the rate of return on common equity, times "b", the retention rate or 1 minus the payout rate, and the term "vs" denotes the growth in dividends due to the sale of new stock which is estimated by the product of "v", the fraction of funds provided by new stockholders that accrue to old stockholders, times "s", the rate of growth in common equity due to the sale of stock. This concept assumes that stock is sold at a market price above book value. Continued sales at less than book value lead to a steady decline in earnings per share. Using this relationship and the smoothing methods described in Chapter 5 of the Gordon text, a theoretical expected growth rate for dividends can be derived. While the cost of equity capital has remained remarkably stable over the past nine years, estimated dividend growth has declined in the past five years to a low of one percent in 1974 (see Table VB-10).

However, even at the lower rates of growth the estimate of dividend growth exceeds the actual dividend growth by a substantial percentage. Actual per share dividends of Moody's 24 utility common stocks grew at 7.05 percent in 1966, but the growth began to decline to a low of 1.67 percent in 1972. The dividend growth rate had recovered to 2.88 percent in 1973. However, this growth rate turned negative in 1974 as average per share dividends fell due to the cut in Consolidated Edison's dividend early that year (see Table VB-11). There is no reason for expecting actual annual dividend growth rates to be exactly equal to the expected long-term growth rate predicted by the Gordon Model, but it is clear that shareholders have not been receiving the returns which they expected.

Table VB-11

PREDICTED VERSUS ACTUAL DIVIDEND GROWTH
(Percent)

Year	Predicted Dividend Growth	Actual Dividend Growth
1974	1.01	(8.60)
1973	3.73	2.88
1972	4.70	1.67
1971	4.53	1.49
1970	5.08	2.17
1969	6.13	2.90
1968	6.01	2.28
1967	6.02	6.83
1966	5.75	7.05

The next step in computing the fixed charge rate is computing the weighted average cost of capital. This rate of return on total investment is the hurdle rate which a utility must earn on a project in order to cover capital costs. This can be computed by the following formula:

$$z = (1.1\, E\, k_e + Bc)/(E + B),$$

E = book value of common equity.
B = book value of debt (including preferred stock)
C = coupon or embedded interest rate on outstanding debt (including preferred stock)
K_e= cost of equity capital.

The formula uses 1.1 times the cost of equity to allow for a 10 percent cost of issuing new shares. For the past seven years, electric utility earnings have not been large enough to cover their financial costs. Until 1974, the earnings shortfall was small, and a rate increase of less than four percent would have been sufficient to cover it. In 1974, the shortfall widened appreciably as interest rates rose much more rapidly than utility rates (see Table VB-12).

Federal Power Commission data indicate that Class A and B electric and combined systems pay out in dividends 70-75 percent of their after-tax profits as measured by the book accounting system reported to shareholders. However, this ratio can be deceptive, as about 40 percent of new common issues are purchased by existing shareholders. Once utilities have proven their earnings with dividend payments, investors appear willing to reinvest their funds in the industry. In the aggregate in recent years utilities have floated new common stock issues equal to nearly 100 percent of the dividend payout.

The effective payout ratio is defined as dividends minus new common stock issued divided by cash earnings. This ratio declined sharply from 63 percent in 1968 to four percent in 1973. Because of the lower amount of new stock financing in 1974, the ratio increased to 35 percent (see Table VB-13). The analysis is applied here to the industry as a whole, individual companies show a variety of behavior with respect to both dividend payout and common stock offerings.

SUMMARY

As plant costs have risen and the combination of long construction lead times and high interest costs have joined to increase utility capital demands while reducing internal cash flow, electric utilities have become increasingly dependent on the U.S. capital markets for funds. The result has been an increase in the cost of capital to the companies as the demand pressure has driven utility interest rates to premium levels. This has reduced the companies' ability to carry higher levels of debt, and constrained them to expand their issuance of preferred and common shares.

Given the current levels of earnings coverage of both interest and dividends, the companies will only be able to raise more capital to the extent that they

Table VB-12

ESTIMATED WEIGHTED AVERAGE COST OF CAPITAL
TO INVESTOR-OWNED ELECTRIC UTILITIES
($ Millions)

	Weighted Average Cost of Capital* (Percent)	Cost of Equity times 1.1 (Percent)	Equity (Millions of $)	Equity Capital Costs***	Preferred Div. and Int.**	Total Columns 4 + 5	Assets	Actual Returns to Capital	Deficit(.) or Surplus Returns****
1974	7.95	12.68	$40,600	$5,148	$5,944	$11,092	$139,450	$9,755	($1,337)
1973	7.23	11.54	37,706	4,351	4,676	9,027	124,794	8,493	(535)
1972	7.26	12.38	33,566	4,121	3,906	8,027	110,616	7,404	(623)
1971	6.75	11.18	29,817	3,333	3,281	6,614	98,045	6,424	(190)
1970	7.19	13.10	26,553	3,478	2,790	6,268	87,220	5,603	(665)
1969	6.61	12.11	23,954	2,901	2,239	5,140	77,794	4,953	(187)
1968	6.28	11.54	22,464	2,593	1,862	4,455	70,976	4,454	(1)
1967	6.13	11.11	21,181	2,416	1,576	3,992	65,085	4,137	145
1966	5.92	10.84	20,139	2,182	1,384	3,566	60,259	3,821	255

NOTE: * Column six divided by column seven.

** Smoothed by equation rate = $\frac{\text{(Preferred Dividends + Int)}}{\text{.5 (Preferred Stock (T) + Debt(T) + Preferred Stock (T-1) + Debt(T-1)}}$

*** Columns five and six smoothed average with proceeding year.

**** Column six minus column eight.

Table VB-13

THE EFFECT OF NEW ISSUES ON THE PAYOUT RATIO
($ millions)

	Earnings Available for Common	AFDC	Available for Common Less AFDC	Dividends	New Common Stock Issues	Effective Payout Ratio (Percent)	New Common Stock Issues as Percent of Dividends (Percent)
1966	2,490	129	2,361	1,629	148	63	9
1967	2,630	189	2,441	1,737	184	64	11
1968	2,681	275	2,406	1,838	326	63	18
1969	2,823	405	2,418	1,880	744	47	40
1970	2,972	594	2,378	2,022	1,411	26	70
1971	3,281	822	2,459	2,191	2,063	5	94
1972	3,721	1,095	2,626	2,402	2,281	5	95
1973	4,083	1,297	2,785	2,656	2,552	4	96
1974	4,193	1,593	2,600	2,865	1,951	35	68

NOTE: Effective Payout Ratio = $\frac{\text{Dividends - New Common Stock Issues}}{\text{Earnings Available for Common - AFDC}}$

can achieve higher levels of revenues and cash earnings. Such earnings increases can, to some extent, permit expanded levels of financing, but it is clear that the trend towards a balance of debt and equity for such financings must be maintained for the forseeable future. Even if interest rates should decline substantially, the embedded costs, the refunding requirements of the industry, and the uncertainty concerning growth projections mitigate against increasing debt/equity ratios. A substantial portion, therefore, of the industry's new financings must be in the form of common stock.