CHAPTER IV

ISSUES IN INVESTMENT EFFICIENCY

As discussed in the previous chapters, a few utilities have experienced economic losses arising from large construction campaigns. According to available evidence, the financial outcome in these cases probably will divide costs between ratepayers and utilities in such a way as to avoid bankruptcy but prolong their financially weakened position. The federal government will bear a portion of these losses through provisions of the tax code that allow utilities to deduct them from taxable income. But beyond this, the need for direct federal intervention is not apparent.

A better case can be made for federal concern with long-term utility investment. Such investment is less sensitive to the immediate allocation of losses than to the more general incentives provided by utility ratemaking. Utilities now are deferring new capacity investments for three reasons: current capacity is adequate; the rate of future demand growth is more uncertain than in the past; and recent regulatory decisions have challenged traditional utility assumptions about the recovery of invested capital. Many utilities have moved toward greater financial flexibility through strategies that postpone the need for new investment--principally by reducing peak load demand and by meeting small increments of demand with power purchased from utilities with excess generating capacity. This approach appears well-suited to current conditions.

Under any reasonable scenario for future demand growth, some new generating capacity eventually will be needed. This raises the central policy issue in long-term electricity supply: the ability of current regulatory incentives to encourage the mix of equipment and fuels best suited to the economic realities of the coming decades. Most of the responsibility for the economic regulation of the electric utilities rests with state authorities. A federal concern also exists, however, not only because an efficient electricity supply contributes to national economic well-being, but also because the federal government is already involved: by regulating wholesale electricity transactions and the organizational structure of the industry; by providing incentives for competition in electricity supply from outside the utility industry; and by influencing the choice of fuels used to generate power.

THE UNCERTAIN DEMAND FOR ELECTRICITY

In September 1985, the North American Electric Reliability Council (comprising representatives of the electric utility industry) published its members' 10-year forecast of growth rates in net generating capacity additions and peak demand. 1/ For the nation as a whole, the electric utilities projected annual growth of electricity peak load would be about 2.7 percent a year from 1985 through 1994, although annual demand growth has averaged about 5 percent over the last two years. Considerable uncertainty persists concerning future load growth. Recent demand forecasts provided to the Congress range from 1.5 percent to 5 percent per year (see Table 7). Most analysts believe that demand growth will fall somewhere in the middle of this range, although individual utility systems may experience even greater variation.

Why is future demand growth so uncertain? First, analysts often disagree about both the future behavior of important economic determinants of demand--such as economic growth, electricity prices, and the prices of alternative fuels--and how changes in these factors, if they could be predicted, would actually affect demand. During the 1960s, for example, real disposable income generally grew at about 4 percent annually. Together with falling electricity prices, this led to demand growth of 6 percent to 7 percent per year. But during the ensuing decade, electricity prices increased threefold and real disposable income grew at only 2.7 percent per year, causing demand to grow only 2.5 percent annually. Currently, most forecasters expect modest GNP growth and decreases in real electricity prices (see Table 7). Low oil and gas prices are, therefore, expected to offset slightly the excessive costs of new nuclear power plants.

Besides these important macroeconomic factors, analysts cannot predict well the technological trends that also affect electricity demand--future industrial electricity needs, efficiency improvements in existing electric equipment and appliances, and the so-called "penetration rate" of equipment using electricity as opposed to gas. 2/ Utilities' own efforts at load management may also affect future demand growth. 3/ A 1983 study

---

1. North American Electric Reliability Council, *Electric Power Supply and Demand, 1985-1994* (1985).

2. See testimony of Dr. Richard E. Rowberg, Office of Technology Assessment, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

3. Load management programs are designed to reduce the need to generate additional power from expensive plants to cover short surges (or peaks) in daily demand. By reducing peak demand--for example, by encouraging consumers to use appliances (washers, dryers, and so forth) during "off-peak" hours--the need for additional, costly plants can be lessened.

TABLE 7. ALTERNATIVE VIEWS OF THE LONG-RUN OUTLOOK FOR PEAK DEMAND GROWTH, ELECTRICITY PRICES, AND GNP GROWTH

Projection	Percent Growth in Annual Peak Demand (forecast period)	Percent Change in Electricity Price (forecast period)	Percent Growth in GNP (forecast period)
Energy Information Administration	3.2 (1985-1995)	-0.3 (1985-1995)	2.7 (1985-1995)
North American Electric Reliability Council	2.2 (1985-1994)	N.A.	N.A.
Data Resources, Inc.	2.2 (1985-1990)	4.6 (1985-1990)	N.A.
Wharton Econometric Forecasting Association	2.8 (1984-1994)	N.A.	2.8 (1984-1994)
Siegel and Sillin	4.0-5.0 (1985-1990)	-1.5 (1985-1990)	3.5-4.0 (1985-1990)
Applied Energy Services, Inc.	2.4 (1985-1990)	-1.0 (1985-1990)	2.7 (1985-1990)
Sant	1.5 (1980-2000)	1.5 (1980-2000)	2.6 (1980-200)

SOURCES: Energy Information Administration (EIA): Annual demand growth rate from Testimony of Dr. Helmut A. Merklein, before the Senate Committee on Energy and Natural Resources, July 25, 1985. Electricity price and GNP growth from EIA, *Annual Energy Outlook 1984*.

North American Electric Reliability Council: *Electric Power Supply and Demand 1985-1994*.

Data Resources, Inc.: DRI Energy Review (Spring 1985).

Wharton Econometric Forecasting Association: Testimony of Mark W. French, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

Siegel and Sillin: Testimony of John Siegel and John Sillin, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

Applied Energy Services, Inc. Testimony of Applied Energy Services before the Senate Committee on Energy and Natural Resources, July 13, 1985.

Sant: Testimony of William Hogan, before the Senate Committee on Energy and Natural Resources, July 23, 1985, Table 1.

NOTE: N.A. = Not available.

estimates, for example, that generating capacity of about 27 gigawatts (roughly equivalent to 27 large nuclear generating stations) that formerly would have been needed by 1992 will not have to be built because of the conservation and load management programs now in place. 4/ Additional utility load management could yield further savings, because less than 1 percent of the residential load is now subject to such techniques. Extension of these methods could help reduce the need for new generation in many service areas, although the effectiveness of such programs is likely to vary widely from location to location. 5/

Implications of Uncertainty for Investment Planning

The wide range of demand forecasts presents a dilemma for utilities. High growth calls for entirely different actions from those needed if low growth occurs. Forecasters of high demand growth believe it may already be too late to prevent shortages by the early 1990s. Those who foresee more modest demand growth warn that starting to build new power plants now could lead to underused capacity or costly cancellations. Utilities were forced to cancel 97 nuclear and 75 fossil fueled plants between 1974 and 1984, in part because of overly optimistic expectations for future demand growth. Analysts predicting low growth, therefore, believe it would be wise to defer new investments in large baseload generation plants until actual demand can be more clearly seen. They note the availability of short lead-time options, such as gas turbines, that provide a "safety valve" in case of an unforseen surge in demand.

Thus, because of demand uncertainty, utilities face two kinds of risk: that of adding capacity to meet demand that is not forthcoming, and that of failing to anticipate demand growth and having to meet it with equipment that is economically unsuited to the task. Both risks involve considerable cost.

---

4. See Investor Responsibility Research Center, *Generating Energy Alternatives: Conservation, Load Management and Renewable Energy at America's Electric Utilities* (1983), cited in Office of Technology Assessment, *New Electric Power Technologies for the 1990s* (1985).

5. When considering the additional uncertainties in the retirement age of power plants, the Office of Technology Assessment has noted that this demand growth range could lead to differences in new capacity requirements in 1995 of as much as 150 gigawatts of capacity (roughly equivalent to 150 large nuclear power plants). See testimony of Dr. Richard Rowberg, July 25, 1985. Also see "How Old Are U.S. Utility Powerplants," *Electrical World* (June 1985).

If, for example, a utility today faced a plausible but uncertain peak demand forecast of 5 percent growth per year through 1995, the utility might choose to forgo building new large baseload capacity now in favor of waiting to see the outcome of demand growth, and then hastily constructing smaller and less efficient units if the demand materialized. If demand growth actually proved to be 5 percent, economic losses would result through the costs of using more expensive fuels and less efficient technologies than the baseload plant would require. But if the utility built a baseload plant to meet the high forecast and demand growth proved less than 5 percent, economic losses would arise from the carrying cost of not using the capital investment. For the utility sector as a whole, these capital-related losses could be even greater than the losses related to operating efficiency (see the following box).

The optimal investment strategy for each utility will, of course, vary according to the utility's service territory, its electricity demand characteristics, the current financial condition of the utility, its access to transmission systems, and the practices of its regulatory commission. 6/ Thus, the example above does not imply that smaller units, instead of baseload plants, should always be built. Rather, it suggests that deferred investment may be the "least-cost" strategy considering the uncertainty about demand growth.

In general, utilities appear to have adopted this deferred investment approach. Construction activity is at its lowest level in more than 20 years despite almost 5 percent demand growth over the 1983-1984 period. Two factors explain this strategy. First, current generating capacity is ample and should remain so in all regions through 1992. For the nation as a whole, reserve margins are above 35 percent, or about 50 percent higher than a decade ago (see following box). National average reserve margins are expected to remain above 25 percent in most forecasts through at least 1995 (see Figure 2). 7/ The Energy Information Administration, for example, does not project national average reserve margins to fall below 23 percent until 1993, although some regions could have reserve margins between 20 percent to 27 percent after 1990. 8/ Demand would have to grow at greater than 3 percent annually from 1983 to 1993 before the reserve

6. See, for example, E. Cazalet and others, "Costs and Benefits of Over/Under Capacity in Electric Power System Planning," *Electric Power Research Institute*, EA-927 (1978).

7. A 15 percent to 20 percent reserve margin is generally considered prudent.

8. A recent DOE staff report also does not foresee any capacity or reliability problems in any region through 1994. See Department of Energy, *Staff Report--Electric Power Supply and Demand for the Contiguous United States 1988-1994*, DOE/IE-003/1 (May 1985), p.4.

THE RISKS OF OVERBUILDING

The utility industry is just emerging from a 15-year period of profound change, during which over 160 baseload plants were abandoned or cancelled because demand growth did not materialize as expected. (Demand growth in the 1970s was only 2.5 percent annually compared with the 7 percent annual growth experienced in the 1960s.) The industry currently possesses substantial excess capacity, and an increase in demand above the anticipated level of 2.7 percent per year would require new capacity additions only after 1990. In light of the high capital costs of new baseload plants and recent regulatory decisions that have limited some utility's cost recovery of plants deemed as "excess capacity," legitimate concern exists about the willingness of utilities to meet higher demand growth *if it occurs*. For these reasons, the costs of investing now to meet a high demand that again might not materialize appears greater than the costs of meeting unexpectedly high demand when it actually occurs with quick-to-build, but expensive-to-operate peaking capacity having a low capital cost.

Consider two cases. In one, utilities decide today that future growth will be 5 percent per year through the 1980s, instead of the 2.7 percent they had recently predicted. To meet expected shortfalls, utilities could begin construction of substantial new capacity (93 gigawatts) in 1986 to enter service in 1993. If demand materialized, industry revenues would grow to meet the added costs without changes in electricity prices. If the added demand did not materialize, however, utilities would have added new capacity eight years sooner than necessary, incurring between $39 billion and $47 billion (in discounted 1984 dollars) in unnecessary carrying costs. (Demand growth below 2.7 percent would delay the need for these plants even longer, thus raising the costs of guessing wrong.)

On the other hand, if the utilities did not change their current building plans and demand did grow at 5 percent per year, power shortfalls in the 1990-1995 period would have to be made up by peaking units that can be built more quickly than new baseload plants. (Building of these plants is assumed to begin after four years of the 5 percent trend). The costs of guessing wrong in this case would be between $31 billion and $41 billion (in discounted 1984 dollars), assuming a rather high 4 cents per kilowatt-hour difference between the cost of using peaking units rather than baseload plants to generate electricity. Although this cost is high, it remains below that of building the larger, more efficient plants and then experiencing lower than expected demand growth.

Two caveats apply to this analysis. First, it is intended to illustrate the magnitude of the costs involved rather than to forecast future events. Second, it says nothing about who bears these costs. Under current regulatory practice, the utilities tend to bear the costs of overcapacity while the ratepayers tend to bear the costs of inefficiency.

RESERVE MARGINS AS INDICATORS OF SYSTEM RELIABILITY

Reserve margins indicate the reliability of power supplies. They generally represent the difference between system capacity and peak demand, expressed as a percentage of peak demand. Disagreement exists concerning their use as a criterion to determine excess capacity, however. Questions have also arisen about the use of reserve margins as indicators of reliability, given the inordinately long construction periods needed for additions to baseload capacity.

One of two approaches to measure reserve margins are typically taken, each of which treats capacity somewhat differently. The first and most commonly used method is to treat capacity as installed (or "nameplate") capacity. This method is referred to as Planned or Installed Reserve Margins. Over the last decade Installed Reserve Margins at the regional level have ranged between 15 and 38 percent, with 20 percent considered reasonably adequate. The second method is to define capacity only in terms of that capacity that is currently or likely to be available during peak load demand periods. This second type of calculation is called the Available Reserve Margins method. Available capacity is always less than installed capacity and it includes adjustments for outages, deratings, and maintenance. Thus, Available Reserve Margins are always smaller than Installed Reserve Margins; historically these have ranged from about 5 percent to 20 percent. 1/

Critics of the Installed Reserve Margins measure argue that installed capacity overestimates capacity actually available. Critics of the Available Reserve Margins method argue that available capacity understates capacity actually available during peak loads by failing to account for regional electricity exchanges and better maintenance scheduling.

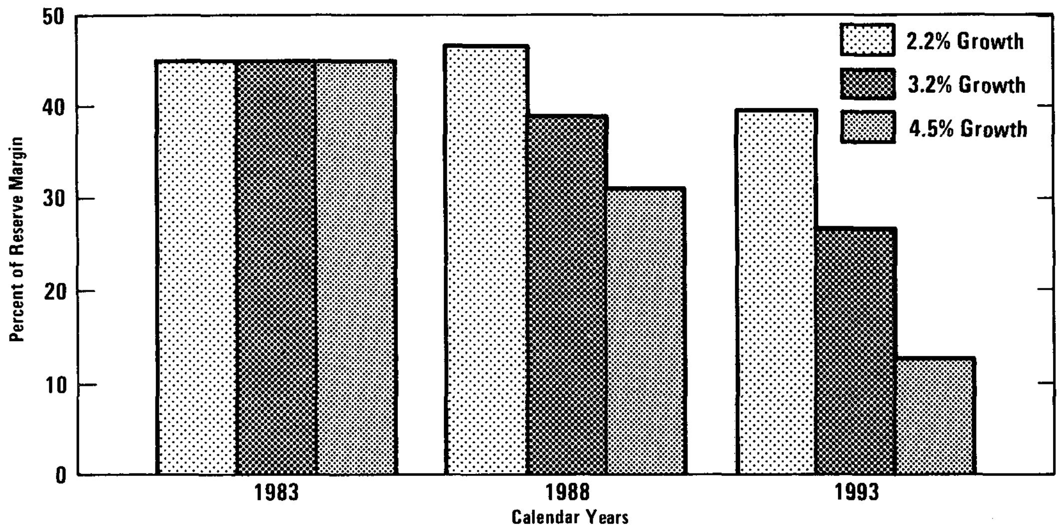
The debate over which indicator ought to be used unfortunately ignores the fact that no indicator ought to be used solely to determine if the system is reliable. Moreover, the optimal size for either Installed or Available Reserve Margins will differ by utility and region. 2/ Differences in demand characteristics, such as volatility and growth, transmission capacity and number of interconnections, and costs of maintaining "backup" capacity will affect the "optimal" reserve margin, regardless of how it is calculated.

---

1. Department of Energy, *Staff Report--Electric Power Supply and Demand.*

2. Examples of how "optimal" reserve margins may differ by individual utility can be found in the sensitivity analyses conducted using the Electric Power Research Institute's "Over/Under Capacity Model." See also Electric Power Research Institute, "Generating Capacity in the U.S. Electric Utilities: An Update," EA-3913-SR (1984); and North American Electric Reliability Council, *An Overview of Reliability Criteria* (December 1982), to find examples of regional differences.

Figure 2.
Electricity Capacity Reserves Under Alternate Scenarios for Demand Growth



SOURCE: Congressional Budget Office based on the following forecasts of demand growth: North American Electric Reliability Council—2.2 percent; Energy Information Administration—3.2 percent; and Siegel and Sillin—4.5 percent.

margin would fall below 20 percent. Second, any utility that begins a new construction campaign probably will incur high capital costs because investors now favor companies that have completed large-scale construction projects and penalize those still involved in construction, especially of nuclear power plants. 9/

Risks of Physical Shortages

Some analysts have raised the possibility that deferred investments now could lead to physical shortages of electricity in the future. 10/ But, even if

9. See Douglas Randall, Standard and Poors Corporation, Summary Remarks to Senate Committee on Energy and Natural Resources, July 25, 1985.

10. See, for example, K.C. Studness, "Why a Shortage of Electric Generating Capacity is All But Inescapable," *Public Utilities Fortnightly (August 1985).*

demand does grow faster than most forecasters expect, it can be misleading to infer future shortages of electricity simply by comparing generating capacity now in place with a high demand scenario. Utilities have many options that can both meet future power needs and serve the utilities' stated financial objective of minimizing the capital they have at risk. These options include: extending the life of current power plants; adding smaller, conventional power plants, such as combustion turbines, that can be built quickly; adding smaller baseload plants, perhaps 500 megawatts or less; encouraging further conservation by customers; and purchasing power from cogenerators or neighboring utilities.[11] Table 8 shows the approximate annual average cost of these options. In addition, highly efficient, modular units employing emerging technologies will become increasingly available, although widespread deployment appears unlikely in this century.[12] [13]

But if physical shortages are not an issue, the incentives for utility managements to select a least costly strategy is. The task of economic regulation is to allow utilities to base investments on their economic and technical merits, rewarding sound choices and penalizing poor ones. Many current practices, however, fall short of that ideal.

---

11. Hugh Holman, "The Next Generation: Capacity Planning for the 1990s," *Public Utilities Fortnightly* (September 5, 1985).

12. Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

13. Utilities' investment options may also be significantly affected by comprehensive revisions to the federal tax code, which are now under consideration by the Congress. See, for example, *The President's Tax Proposals to the Congress for Fairness, Growth and Simplicity* (May 1985). Probably most important from the standpoint of utilities' plans for new capital investment--other than the overall uncertainty as to what demand changes will actually take place--are the Administration's proposals to repeal the investment tax credit program and to adopt a new capital cost recovery system. On balance, it appears that the President's plan could make future utility investment in new generating plants more attractive than at present, primarily because the President's plan would lower the current corporate tax rate from 46 percent to 33 percent. Specific changes could severely affect individual firms, however, depending on their individual tax position and the nature of the change. For example, utilities that had claimed large depreciation writeoffs over the last five years could be forced to pay a special windfall recapture tax under the President's proposal. See "Tax Plan: Smokestack View," *New York Times*, July 2, 1985. In addition, the Administration is also proposing changes in the accounting treatment of investment tax credits that could benefit ratepayers. See "Billions At Stake in Tax Dispute," *Energy Daily*, September 4, 1985. Both of these proposals could strain a company's short-term cash flow in some cases.

TABLE 8. COSTS OF SUPPLYING ELECTRICITY, BY TECHNOLOGY OPTION (In 1984 dollars)

Electricity Source	Cost (cents per kwh)
Baseload Plant a/	
Coal Fired (500 megawatts)	4.23
Peaking Units a/	
Natural Gas-Combined Cycle (250 Mw)	4.85-6.25
Natural Gas-Combustion Turbine (75 Mw)	6.85-7.56
Resid Fired-Combined Cycle (250 Mw)	5.70-7.34
Cogeneration b/	4.0-7.0
Upgrade of Existing Plant c/	2.0-6.7
Purchased Electricity d/	2.0-7.0

SOURCE: Congressional Budget Office.

a. Capital, operating and maintenance costs from Electric Power Research Institute (EPRI), *Technical Assessment Guide*. Exhibit App. B4-4b, BH-16b, B4-18b all for the East/West Central regions (Palo Alto, Calif: EPRI, May 1982). Fuel prices from Energy Information Administration, *Annual Energy Outlook 1984*, Tables 16, 17, 18 (January 1985). Price spread for peaking units results from number of years for capital recovery. Lower cost is for capital recovery over 20 years. Higher cost is for capital recovery over five years, and in which case a utility plans to have baseload capacity coming on line at the end of that time period.

b. See "States' Cogeneration Rate-Setting Under PURPA, Part 4," *Energy User News*, Vol. 9, No. 40-43 (October 1984).

c. Costs are highly project specific. See Office of Technology Assessment, *New Electric Power Technologies* (July 1985), Chapter 5.

d. Energy Information Administration, *Financial Statistics of Selected Electric Utilities in the United States*. The large spread reflects cost differentials in excess power availability stemming from geography, current reserves, month of sales, and so forth.

REGULATORY ISSUES IN INVESTMENT CHOICE

About 70 percent of the electricity in the United States is supplied by privately owned utilities. 14/ These firms are franchised monopolies, legally

14. Most of the remaining electricity is generated by a number of publicly owned enterprises consisting of six federal power systems, 900 rural cooperatives, and 2,200 municipal, state, and regional power authorities.

obligated to provide electric energy to specific territories. To meet demand growth, they must build new plants, and to build plants they must raise large amounts of capital from earnings, stock sales, and the bond markets. This has made electric power one of the most capital intensive industries in the United States, accounting for 20 percent of all industrial capital investment, one-third of all corporate financing, and one-half of all new common stock issuances.[15] It also implies, however, that the regulatory treatment of capital investment is the salient long-term issue for the electric power industry and its customers.

Interstate transactions for wholesale electricity, about a third of all electric utility sales, are regulated by the Federal Energy Regulatory Commission (FERC). But the bulk of electricity transactions are retail sales of electricity, and these are regulated by state public utility commissions. The major concerns of each state commission are to assure that ratepayers are given reliable service at "just and reasonable" rates and that utilities providing such service are allowed returns adequate to attract capital. The commissions accomplish these goals through rate regulation.

The Hope Decision

Current state and federal ratemaking practice is based largely on the Supreme Court's Hope Natural Gas case of 1944.[16] The court's decision essentially set forth three principles that guide state regulation:

- Investors in utilities should earn a return comparable with that earned in other businesses with similar risks and uncertainties;
- The allowed return should ensure the financial integrity of investments in a utility; and
- The allowed return should be sufficient to attract the necessary capital for future construction projects.

The Hope decision became the precedent that state regulators follow in assessing adequate revenue requirements for utilities in their jurisdic-

15. Scott Fenn, *America's Electric Utilities: Under Siege and In Transition* (New York, N.Y.: Praeger, 1984).

16. *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944).

tions. But it established no precise formula for doing so. Under the Hope criteria, utility revenues are considered adequate when revenues from electricity sales cover the cost of providing electricity plus a "fair" rate of return on the value of the utility's assets (the rate base). It did not matter to the court whether a utility earned a low return on a high capital base, or a high return on a small base, as long as these principles were upheld. As a result, state regulators now have considerable discretion with regard to the actual procedures used to determine rates.

Two closely related concerns have dominated current thinking about the regulatory treatment of utility capital investments. The first is the treatment of the capital that is committed during the lengthy construction of a modern power plant. Allowing the utility to charge ratepayers for all or a major portion of these committed funds would improve cash flows significantly and reduce the business risk of major projects. On the other hand, it might reduce incentives for construction efficiency and the consideration of less capital-intensive alternatives.

The second concern is the bearing of risks and rewards. A utility's legal obligation to provide electricity service for its area creates strong pressures to assure generating capacity. Constructing a plant that is both timely and cost-effective can provide significant savings to customers, without necessarily providing the utility greater profits. On the other hand, overbuilding to meet a forecast demand that does not materialize produces surplus capacity. Either electricity customers must pay for this capacity they cannot use immediately, or the utility and its investors must assume the costs. The division of these risks and rewards between the utility and its customers is a major regulatory issue.

Charging for Construction Work in Progress

A central question in electricity ratemaking is the treatment of plants under construction--namely, when charges should be included in electricity rates and how high they should be. Each state utility commission treats the recovery of new plant investment differently. About half the states have, on occasion, incorporated a portion of the construction work in progress (CWIP) into the rate base. This treatment allows utilities to recover part of the costs of CWIP before the plant becomes used and useful.

When CWIP is not allowed in the rate base, state regulators generally provide an "allowance for funds used during construction" (AFUDC). As most widely applied, AFUDC is an accounting method for treating the financing costs of plants under construction and deferring those costs until the plant is completed and entered in the rate base. Under AFUDC, construction expenditures for plants not yet in service are set aside in a special account which is listed as an asset on the balance sheet. This account is merely a tabulation of the accruals allowed for return of capital expenditures. This "asset" earns an allowed return just as any other utility rate base property, but the calculated return is not realized as cash income by the utility until the facility is placed in service. Until then, the utility must maintain its cash flow in other ways, often by issuing debt.

To the extent that an AFUDC account is used to defer the return on invested capital, the utilities' shareholders bear the risks of lower than expected demand, delays in power plant completion, and cost overruns. This practice can lead to several difficulties for utilities. First, electricity consumers are initially shielded from one price effect of their consumption--the need for new capacity--and later presented with sharp rate increses. At the same time, the utility's ability to make additional investments is constrained by cash-flow limitations and the recognition by investors that business risk has been increased by the lower quality of earnings. Finally, if the demand for electricity proves to be less than forecast when the plant was begun, the utility may be required to bear the carrying costs of the excess capacity until it becomes used and useful. (The differences between AFUDC and CWIP ratemaking are discussed at greater length in Appendix A.)

Sharing of Risk and Reward

In contrast with capital costs, the fuel costs of producing electricity are recovered quickly in most states, often through "fuel adjustment clauses." These allow all or part of increases in fuel prices occurring between rate hearings to be recouped, usually with minimal delay, in order to ensure enough cash flow to purchase fuel. Thus, ratepayers usually bear the risks of higher electricity costs caused by fuel price increases, and stockholders generally bear the risk that some portion of their invested capital will be lost or earn less than the anticipated return.

Beyond these general tendencies in assignment of risk, however, utilities face considerable uncertainty regarding the treatment of capital charges, as few states have firm standards for rate treatment of CWIP. For completed plants, many state commissions are reinterpreting the used and useful standard of plant cost recovery to require that a new plant is actually used to meet current demand and is not simply operational. 17/

Such decisions lend credence to utilities' claims that they face an "assymmetry of risk" in the present regulatory environment. In this view, state regulators pass on to ratepayers the savings achieved when utility management makes the right decisions, but are not as willing to pass on cost increases for construction efforts rendered unnecessary because of changing demand conditions. Indeed, many utilities have stated they will not build new baseload plants, regardless of demand, until these regulatory conditions change. 18/

Not all the efforts of regulators to shield consumers from extreme price increases have been financially detrimental to utilities, however. Indeed, many utilities have proposed that rate commissions not enter the entire cost of a completed plant into the rate base at once, but rather phase it in over several years to allow customers a period of adjustment to the higher prices. Although this delays the cash return on investment, it does not necessarily eliminate it, because the unincluded portion of the plant's cost continues to earn an AFUDC return until it enters the rate base.

Similarly, most current practices do not represent a marked departure from the rules under which regulators and utilities have always operated. Recent rate base disallowances of imprudently incurred costs--such as the New York commission's $1.5 billion disallowance of the costs of Shoreham because of poor management oversight--are based not on a new standard but on the prudency standard that has always guided utility ratemaking. As for exclusions of excess capacity from the rate base, some state officials note that utilities are responsible for monitoring demand changes at each stage of construction to ascertain the least expensive method of meeting future load. Thus, if demand conditions change, the prudent utility would cancel construction and the reasonable regulatory commission would grant some

17. The most extreme form of this type of judgment was the Colstrip case, in which the Montana Public Service Commission denied the Montana Power Company any rate relief for a completed coal-fired plant, asserting that the used and useful criterion is met only if the plant is needed at the time it goes into service. See *In the Matter of the Application by the Montana Power Company for Authority to Establish Increased Rates*, Montana PSC Order No. 5051C, August 3, 1984. The Montana Supreme Court, however, later reversed this decision on the grounds that the regulatory standards were changed after the plant was completed.

18. See, for example, Statement of Keith Turley, Chairman of the Board, Arizona Public Service Company, before the Senate Committee on Energy and Natural Resources, July 23, 1985.

recovery of the utility's sunk costs. The problem for utility management, however, is the after-the-fact determination by regulators that the utilities should have foreseen events that were clearly beyond the scope of any forecasting method.

CONCLUSION

In light of the nationwide abundance of generating capacity and the considerable uncertainty that surrounds future demand, the strategy of financial flexibility now preferred by most utilities has much to recommend it. Of greater concern, however, is whether the incentives provided by current rate-base regulation are likely to lead to an efficient mix of capital investment and fuels once demand growth necessitates new generating capacity. While current practices are likely to result in widespread electricity shortages, the nation's electricity supply could become less cost-effective if regulatory incentives continue to bias utilities away from capital investments regardless of their technical or economic merit. Although state regulators have the primary responsibility for the financial incentives of the electric utility industry, the Congress might consider several options to move the electric system toward greater economic efficiency. These are discussed in Chapter V.

CHAPTER V

FEDERAL OPTIONS FOR LONG-TERM EFFICIENCY IN UTILITY INVESTMENT

The utility industry has responded to an increasingly risky business environment by adopting strategies that emphasize flexibility and limit capital exposure. While this response is unlikely to lead to widespread physical shortages of electricity, it does raise doubts about the ability of current regulatory practices at both the state and federal levels to provide incentives for the most efficient mix of generating equipment, fuel use, and conservation practices. State regulators have the greatest leverage here, but the Congress could also consider federal options to improve efficiency.

This chapter examines alternative federal policies to promote more efficient choices for utility investment. The following options are discussed:

- Establish federal ratemaking guidelines to help reduce regulatory uncertainty at the state level;

- Revise the Public Utility Holding Company Act to enable utilities to diversify their investment risks;

- Amend the Public Utility Regulatory Policies Act to allow more efficient electricity pricing and utility ownership of cogeneration facilities;

- Change federal regulatory policies and the federal tax code to promote "fuel neutrality" in utilities' investment choices; and

- Encourage efficient use of transmission facilities to allow low-cost generation to displace high-cost generation.

These changes, alone or in combination, could help restore the environment for more efficient utility investment. (These options are summarized in Table 9.) Because the federal role in utility regulation remains somewhat limited, however, appropriate state and utility action is crucial if large efficiency gains are to be realized.

TABLE 9. FEDERAL OPTIONS TO PROMOTE LONG-TERM EFFICIENCY IN UTILITY INVESTMENT

Option	Description	Relative Effectiveness of Option
Standardize Ratemaking	Would establish nonbinding regulatory guidelines for state commissions, such as staged plant construction review.	Could provide greater certainty for utilities' future power planning efforts and prospects for investment cost recovery, but would need state-initiated legal changes.
Liberalize Public Utility Holding Company Act	Would remove restrictions on utility diversification.	Could provide utility management with greater flexibility to diversify holdings that could yield ratepayer benefits, but could also lead to diversion of utility assets into riskier, nonregulated lines of business.
Change Public Utility Regulatory Policies Act	Would allow utilities to own majority interests of cogeneration facilities.	Could provide greater certainty for utilities' future power planning efforts and greater incentives for cogeneration investments by utilities, but could also reduce nonutility cogeneration investment incentives.
Promote Fuel Neutrality in Utilities' Investment Choice	Would end restrictions on natural gas use, restore equal tax depreciation periods for nuclear and coal plants.	Could allow alternative fuels to compete on a more equal basis, but certain changes could conflict with other energy policy goals, such as reducing dependence on foreign oil.
Encourage Expanded Transmission Capabilities	Would promote efforts to increase utilities' power interconnections.	Could improve power distribution efficiencies, reduce need for new generation investment; but construction of new transmission lines could incur significant costs and delays because of existing siting requirements.

SOURCE: Congressional Budget Office.

STANDARDIZE RATEMAKING PRACTICES THROUGH FEDERAL GUIDELINES

To help balance the risks and rewards of new investment, the federal government could develop nonbinding guidelines for states to follow in reviewing new plant construction. These guidelines could suggest state approaches to cost-effective investment through more balanced treatment of the risks of excess capacity and less efficient generation. For example, state regulatory commissions could consider better ways to share the responsibility for predicting demand. States could approve (or disapprove, as appropriate) plant costs at several stages in the construction process. This staged review would lower investment risk by guaranteeing eventual cost recovery of the approved portion of the project, even if these costs were not immediately included in the rate base. It would forewarn of changes in demand growth and enable the utility either to abandon construction or to mothball the plant for future use if conditions warrant. The State of Indiana has taken this approach in a law enacted in April 1985. 1/

Other guidelines might allow the utility a higher rate of return on cost-effective investments. When new capacity results in net "avoided costs," some portion of the savings could be reflected in utility earnings, thus giving these companies a direct financial stake in providing the least costly generation. 2/ In addition, incentives to improve productivity could be included in guidelines for ratemaking. For example, a utility could be guaranteed that 80 percent of input price increases could be passed to its customers. Thus, if annual input prices rose by 15 percent, the utility would be permitted to pass a 12 percent price increase along to its customers. If the utility had improved its productivity by 3 percent, its profits would not be affected. If productivity grew at less than 3 percent, the company would lose money. But if productivity rose at over 3 percent, it would increase its earnings. 3/ Of course, the precise specification of such an approach would

1. Under Indiana Senate Act 546 (signed into law April 1985), the state commission is required to review the continuing need for a utility's project and approve past construction work at the request of the utility. If the commission then approves the construction and the cost of the portion of the facility under review, "that approval forecloses subsequent challenges to the inclusion of that portion of the facility in the public utility's rate base on the basis of excessive cost or inadequate quality control." This procedure does not apply to facilities begun before 1985, such as PSI's Marble Hill plant.

2. See, for example, M.J. Smith and W. Dickter, "Living With Standards of Performance Programs," *Public Utilities Fortnightly* (August 16, 1984); and Edison Electric Institute, *Incentive Regulation in the Electric Utility Industry* (May 1984).

3. See William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities Fortnightly* (July 22, 1982) pp. 11-18.

vary from utility to utility and from year to year. But inclusion of such concepts in regulatory practice could give additional incentives for efficient operation. Approaches such as these might better balance risk and reward in states seeking ways to give their utilities greater responsibility for the economic outcome of investment decisions.

The federal government has had little influence on state ratemaking in the past, however, and it is uncertain how much real effect voluntary guidelines could have. Voluntary guidelines could even be seen as a federal intrusion into the traditional prerogatives of state regulation, and could encounter resistance independent of their economic merit. 4/ In addition, state regulatory commissions and legislatures themselves may alter many current rate practices in response to the recent difficulties caused by expensive construction programs, as discussed in Chapter II.

Suggested federal guidelines also should be designed carefully to avoid overencouragement of baseload construction relative to other alternatives, such as conservation or investment in smaller, modular facilities. 5/ Indeed, utilities and their investors might still prefer the flexibility offered by lower capital cost alternatives to adding to or replacing baseload capacity, even though the cost of supplying electricity with these alternatives might be somewhat higher. Federal efforts in regulatory reform should also recognize that the costs of imprudent investment decisions must still be borne by stockholders, and that investment risks associated with normal market forces cannot be completely eliminated.

REVISE PUBLIC UTILITY HOLDING COMPANY ACT

As noted in Chapter III, mergers with other companies can be one solution to the financial troubles of a distressed utility. For the longer term, utility mergers could, in certain instances, provide greater cost efficiencies in electricity service. Some public utilities are also becoming increasingly interested in diversification into unregulated lines of business as a means of improving their overall risk profile. Provisions of the Public Utility Holding Company Act (PUHCA), however, could deter utilities from engaging in these activities. Liberalizing certain provisions of the act has, therefore, been suggested as a means to enhance the industry's long-term investment flexibility.

---

4. See, for example, *FERC v. Mississippi*, 456 U.S. 742.

5. For a discussion of the potential benefits of conservation investments through end-use efficiency improvements, see Rocky Mountain Institute, *Least-Cost Electrical Services as an Alternative to the Braidwood Project*, Illinois Commerce Commission Docket #82-0855, 83-0035, July 3, 1985.