Chapter 8

Potential Role of Utilities in Improving the Energy Efficiency of Buildings

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Chapter 8

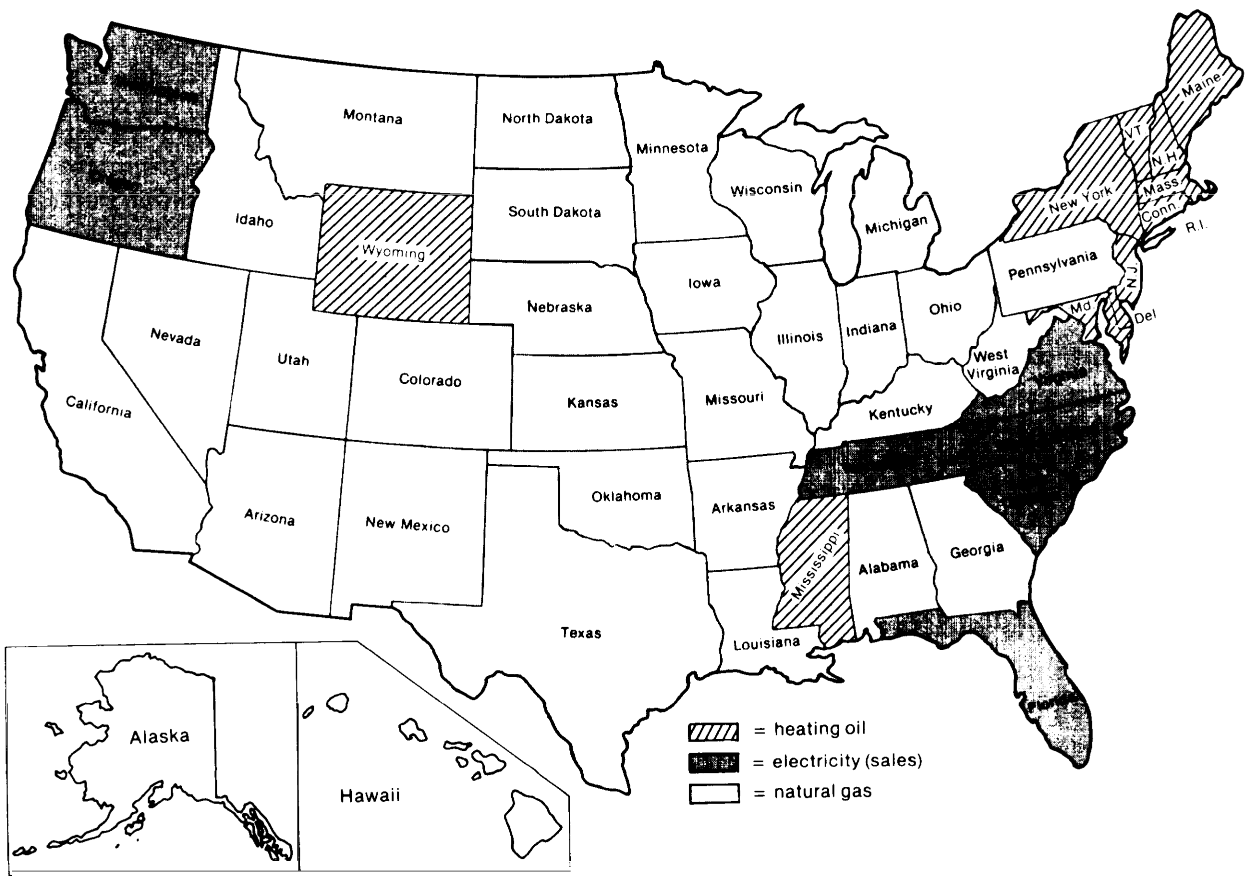
Potential Role of Utilities in Improving the Energy Efficiency of Buildings in Cities

In response to the problems caused by sharp increases in oil and gas prices and periodic oil and gas shortages, and sharp increases in the cost of capital and powerplants, many utilities have undertaken energy conservation programs. Both the Tennessee Valley Authority (TVA) (see box N below) and pacific power & Light, for example, have aggressive programs for marketing energy audits and retrofits using zero- or low-interest loans.

To what extent are other utilities likely to follow the leadership of these utilities with unusually strong energy conservation programs? The purpose of this chapter is to examine the several motives utilities have for energy conservation programs and to assess the likelihood that utility programs will contribute significantly to the large-scale retrofit of city buildings.

This chapter discusses the incentives of both gas and electric utilities to develop building energy conservation programs. Natural gas is the dominant source of energy for residential and commercial buildings in **27** out of **50** States (see fig. 52). Electricity is the dominant source of energy for buildings in only eight States. (Heating oil is the dominant source in 15 States.)

Figure 52.—Dominant Source of Energy/Fuel for Residential and Commercial Buildings



SOURCE: Department of Energy, April 1980 State Energy Data and the Off Ice of Technology Assessment

Many utilities sell both gas and electricity. Of the 56 electric utilities listed in table 78 below, 25 also sell natural gas.

- For both gas and electric utilities, audit programs can improve customer relations in a time of sharp increases in prices.
- For both gas and electric utilities, unregulated energy management subsidiaries can be profitmaking.
- For a few gas utilities, savings in gas used by regular customers can be used profitably to sell to new customers, or at greater prices.
- For certain electric utilities certain kinds of energy management programs will allow postponement of the construction of a new generating plant.

Each of these possible reasons for an energy management program will be discussed first from the point of view of utilities considering such programs. Consumers of electricity and potential competitors of utilities for the energy management business also have reasons for providing or withholding support from utilities seeking public authority to conduct such programs. These two additional points of view will be discussed at the end of the chapter.

CONTEXT FOR UTILITY DECISIONMAKING

Most observers of the electric utility industry in 1981 concur that the industry is in trouble resulting from failure to adjust to a set of changed circumstances in the 1970's that brought to an end the golden era of electric utility prosperity of the previous two decades. The symptoms of the trouble include declining real returns on equity (for investor-owned utilities), declining coverage of interest on debt, deteriorating bond ratings, and low market-to book ratios of stock values.[1] Some utilities and some observers of utilities have recommended energy management programs as one of the responses to this deteriorating situation.

Gas utilities, which distribute natural gas but do not have responsibility for producing it, also confront the results of higher prices and slower growth in demand since the embargo. Following are the most important changes to have affected electric and gas utilities over the decade:

Gas Utilities. Average prices for residential use of natural gas almost quadrupled from 1970 to 1980, increasing from $1.06 per million Btu to $3.81 per million Btu.[2] The numbers of residential heating customers continued to increase but far more slowly than in the two previous decades. By 1978 and 1979, the number of natural gas customers was increasing at less than 1 percent per year.[3] In quantities of natural gas sold, residential and commercial sales of natural gas were essentially stagnant from 1976 to 1980 and industrial sales decreased from the early 1970's.[4] Natural gas distribution companies collect a distributor's markup on the wholesale gas sold to them by the natural gas production and pipelines companies. Increased prices for natural gas at the well head do not result in increased distributor's profits and stagnant or declining sales makes it harder to carry the cost of the distribution system. The gas distribution companies bear the brunt of consumer resentment of increased prices although the companies do not profit from them.

Electric Utilities. A set of semiindependent changes in the circumstances of electric utilities have brought about the current situation. They are:

Rapidly increasing prices and threatened shortages of fuel oil and natural gas. Utilities

[1]This section draws on background on the electric utility industry prepared by OTA for a forthcoming report, Cogeneration. It also draws on several published sources: Leonard S. Hyman, The *Development* and Structure *of the Electric Utility Industry*; Merrill Lynch Pierce Fenner and Smith, Institutional Report, New York (December 1980); Charles M. Studness, "Genesis of the Current Financial Plight of the Electric Utilities," *Public Utilities Fortnightly* (June 19, 1980).

[2]Energy Information Administration, *1980 Annual Report to* Congress, April 1981.

[3]American Gas Association, *1*979 Gas Facts, 1980, p. 72.

[4]American Gas Association, op. cit., p. 83.

relying on oil and natural gas for electricity generation have had to increase their prices very rapidly. These are predominantly in the East and Southwest as is clear from the map of fuels used in producing electricity shown in figure 53. To avoid paying the fuel cost of oil and gas and avoid problems of fuel shortages, they have attempted to shift to far more capital intensive nuclear and coal generating plants.

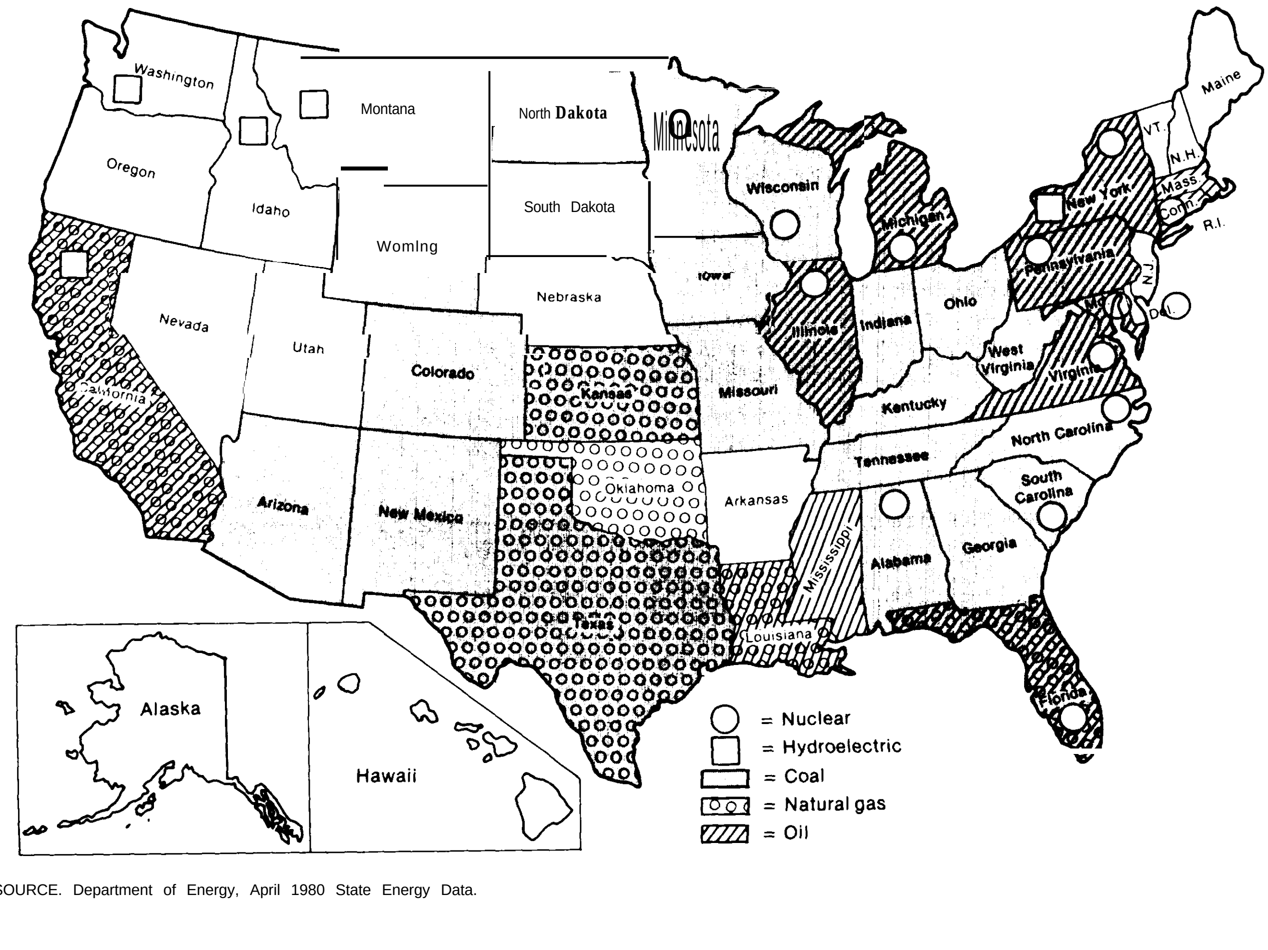
Increasing powerplant construction costs. Over the decade, the cost of a nuclear or coal powerplant has increased much faster than the cost of living and is projected to continue to increase rapidly over the next decade. TVA's first nuclear powerplant came on line in 1975 and cost $270 per kW of capacity. Another TVA nuclear powerplant scheduled to come on line in 1989 is estimated to cost $2,400 per kW of capacity, a ninefold increase[5] In the industry as a whole, the average cost per kW of generating capacity increased from $166 in 1973 to $796 in 1978.[6] The reasons for this increase include a shift to more expensive forms of electric generation using coal and nuclear energy, and more environmental and safety requirements.

Increasing cost of financing. Increased cost of finance over the decade multiplied the impact of increased construction costs. Interest on new long-term debt issued by investor-owned utilities that had hovered below 6 percent in the

[5] Robert L. Sansom, *Major Policy Issues Facing the Tennessee Valley Authority and Its Rate Payers*, a report submitted to the Committee on Environment and Public Works, March 1981.

[6] Hyman, op. cit., p. 48.

Figure 53.—Sources of Energy for Electricity (all sources contributing more than 100 trillion Btu to a particular State)



SOURCE. Department of Energy, April 1980 State Energy Data.

mid-1960's, rose to about 8 percent by 1973, and climbed to 14 percent by 1980. Increase in average interest rates was due partly to the general increase in interest rates over the decade and partly to large-scale downrating of utility bonds.[7] Publicly owned utilities and Federal power agencies (discussed below) experienced a similar increase in the interest cost of their generally lower priced debt.[8]

At the same time, equity capital also became more expensive for investor-owned utilities. A combination of competition from high-interest rates in the bond market and decreasing confidence in utility stocks (especially following Consolidated Edison's failure to pay a dividend in 1974) has caused a sharp drop in the average price of utility stock. The ratio of the market value of utility stock to its book value has fallen from a high of 2.35 in 1965 to about 1.0 in 1973 to 0.80 in 1978.[9] In 1981, the stock of virtually all the major utilities sells at a price below book value (shown in the statistics on 59 utilities and utility holding companies in app. A). For stock selling below book value, more shares must be issued to raise the same amount of capital than if the stock were selling at book value. Each sale of stock at below book value drives the market price down still further and dilutes its value for existing stockholders (see the explanation of this phenomenon in app. B).

[7] Edison Electric Institute, Statement presented at a Public Conference on the Financial Condition of the Electric Utility in the United States, sponsored by the Federal Energy Regulatory Commission, Mar. 6, 1981.

[8] See Sansom, op. cit., p. 5.

[9] Hyman, op. cit., p. 47.

Failure to adjust to lower rates of growth in electricity sales. During the decade of the 1960's, sales of electricity grew much faster than the gross national product (GNP), stimulated by falling real prices of electricity. By the late 1970's, sales of electricity increased somewhat more slowly than GNP in response to the first real increase in electricity prices.[10] Many utilities had embarked on building programs to accommodate the 7-percent annual growth rate of the 1960's. Many failed to cut back their plans for new generating capacity and wound up at the end of the decade with margins of reserve generating capacity far beyond the 20 percent considered prudent by the industry. overall, the reserve margin for the entire investor-owned electric utility industry increased from an average of 21 percent in 1973 to 34 percent in 1978.[11]

These averages conceal a wide variation in experience from region to region and from utility to utility within the same region. Sales for some utilities in the Southwest grew 6 and 7 percent per year from 1973 to 1979 while several utilities in the New York/New Jersey region experienced stagnant or declining sales over the same period (see table 71). Growth rates in the price of electricity also differed sharply from utility to utility, The residential electric rate charged by Puget Sound Power & Light increased at 7 percent per year, slower than the general price increase, while prices for Long Island Lighting increased at an average of almost 16 percent per year.

[10] Hyman, op. cit., pp. 40-41.

[11] Hyman, op. cit., p. 43.

Table 71.—Rate Increases and Demand Growth Over the Past 5 Years for Utilities in Various Urban Areas

Utility	1979 residential rate (c/kWh)	1973-1979 average annual increase in residential rate (percent)	1979 kWh sales (10^6)	1973-1979 average annual increase in kWh sales (percent)
New *England:*				
Boston Edison ... , ...	6.4	10.2%	12,155	1.2%
New England Electric (H)	6.0	11.2	16,372	1.0
Northeast Utilities (H)	5.2	9.2	20,485	1.3
Public Service of New Hampshire . . .	5.8	13.1	5,602	3.5
United Illuminating	6.2	14.1	4,780	.6
New York/New Jersey:				
Consolidated Edison	**10.5**	**12.5**	**29,350**	**– 2.8**
Long Island Lighting	7.2	15.8	13,319	1.1
Niagara Mohawk Power ... , ...	4.4	9.1	32,483	.5

Table 71 .—Rate Increases and Demand Growth Over the Past 5 Years for Utilities in Various Urban Areas—Continued

Utility	1979 residential rate (¢/kWh)	1973-1979 average annual increase in residential rate (percent)	1979 kWh sales (lo')	1973-1979 average annual increase in kWh sales (percent)
Orange & Rock Utility	8.5	15.7	3,436	.1
Public Service Electric & Gas	7.0	12.7	29,587	.3
Rochester Gas & Electric	4.6	8.2	6,690	-.3
Midatlantic:				
Baltimore Gas & Electric.	5.0	8.8	16,823	2.7
Delmarva Power& Light	5.9	10.7	7,491	6.4
General Public Utilities (H)[a]. . .	6.1	12,8	12,770	3.1
Pennsylvania Power & Light ., ...	4,2	9.6	22,555	3.0
Philadelphia Electric	5.8	9.2	27,559	.8
Potomac Electric Power	5.0	11.4	15,676	1,4
Virginia Electric & Power	5.1	14.2	37,575	3.8
Duquesne Light	6.2	12.8	13,575	1.3
South *Atlantic:*				
Carolina Power & Light ., ., ...	4.1	12.8	28,667	2.9
Duke Power.	3.9	10.9	50,323	2.6
Florida Power & Light ., ...	4.7	12.7	41,965	4.4
Gulf State Utilities ., ...	3.9	8.1	29,741	5.4
Kentucky Utilities	3.9	9.2	10,166	6.0
Louisville Gas & Electric	3.7	10.2	7,794	1.2
Middle South Utility (H)[b] . .	3.0	7.1	23,252	4.4
South Carolina Electric & Gas ., . .	4.7	12.8	11,251	1,2
Tampa Electric	5.2	14.5	10,141	4.4
Midwest:				
Cincinnati Gas & Electric	3.9	6.9	12,190	3.0
Cleveland Electric & Illuminating. . .	5.5	12.7	19,030	1.2
Commonwealth Edison	5.1	9.0	64,057	1.9
Dayton Power & Light ., ., ...	4.6	12.5	10,234	3,3
Detroit Edison	5.1	11.7	36,891	.7
Illinois Power	4.3	8.2	14,225	5.0
Northern Indiana Public Service.	5.5	11.9	14,007	4.0
Northern States	4.2	8.0	22,579	5,3
Minnesota Power & Light ., . .	5.1	10.1	8,357	9.5
Ohio Edison	5.4	12.9	19,614	1.8
Toledo Edison	5.9	14.4	7,708	2.6
Wisconsin Electric Power . . .	4.4	9.2	17,670	4.6
Southwest:				
Houston Industries	4.1	13.9	52,360	7.1
Oklahoma Gas & Electric	3.6	8.6	19,992	5.8
Southwestern Public Service	5.2	11.6	11,378	5.6
Texas Utilities (H)[c] . . .,.	4.1	10.4	24,799	6.9
Central:				
Kansas City Power & Light	5.4	11.7	8,218	2.5
North Central				
Montana Dakota Utilities	4,2	7.6	1,500	2.5
Public Service Colorado	4.2	7.8	14,296	7.7
Utah Power & Light	4.3	11.8	15,171	11.3
West:				
Arizona Public Service.	5.6	13.9	11,584	6.1
Pacific Gas & Electric	3.5	7.5	59,815	1.8
San Diego Gas & Electric	5.3	13.8	9,851	3.9
Southern California Edison, ...	4.7	8.3	59,518	1,6
Tuscon Electric Power.	5.9	11.6	6,244	9.5
Northwest:				
Pacific Power & Light	2.6	9.5	22,843	4.3
Portland General Electric ., ...	2.8	12.9	13,652	—
Puget Sound Power & Light	2.0	7.0	13,977	7.0

[a]General Public Utilities includes Jersey Central Power & Light and Metro Edison (Reading). Jersey Central Power & Light (the largest of the two) figures are shown here

[b]Middle South Utility includes Arkansas Power & Light; Arkansas-Missouri Power Co., Crossett Electric; Louisiana Power & Light, New Orleans Public Service; and Middle South Services Louisiana Power & Light (the largest utility in the holding company) figures are shown here.

[c]Texas Utilities includes Dallas power & Light; Texas Electric Service Co., Texas Power and Light; Texas Utilities Fuel Co.; Texas Utilities Generating Co , and Texas Utilities Services, Inc Texas Power and Light (the largest utility in the holding company) figures are shown here

(H) = Holding company

SOURCE Electrical World, Directory of Electric Utilities, 1974-1975, 83rd edition, 1974, and 1980-1981, 89th edition, 1980.

Reserve margins also differ significantly among the nine Regional Reliability Councils (utilities coordinating power demands). As is clear from table 72, three of the Reliability Councils (West, Mid-Continent and Mid-America) are operating with reserve margins no higher than the prudent 20 percent. Texas, however, has a reserve margin of 36 percent and the Northeast a reserve margin of 37 percent.

Declining relative return on equity. over the decade from **1970,** the average percent return on common equity fell from 11.8 to 11.0 percent, further and further behind the average authorized return on equity granted in utility rate decisions.[12] (See table 73.) Actual earned returns on common equity failed to keep up either with inflation or with the increasing interest rates in the bond market. State regulatory commissions, faced with vocal public opposition to increases in electricity costs have resisted large rate increases. Even substantial rate increases have proved inadequate for utilities where sales have not grown as rapidly as expected. As inflation got worse, lags in regulatory adjustment of rates undermined rate relief. States differ in the return they are willing to give utilities, in the speed of decision making on rates, and in the accounting rules they use in computing rates. (The Solomon Bros. rating of State utility commissions and a summary of their practices is shown in app. C.)

[12] Edison Electric Institute, op. cit., tables 3 and 15.

Table 72.–Projected Reserve Margins: July 1980 and February 1981 (in percent)

Regional Reliability Council	July 1980	February 1981
Northeast Power[a]	43%	*37%0*
Mid-Atlantic Area	28	*48*
East Central Area	27	*35*
Southeastern	27	*28*
Mid-America[a] (Mo., Wis., Ill.)	21	
Southwest	26	*65*
Mid-Continent Area (N. Dak., S. Dak., Minn., Iowa, Nebr.)	21	51
Texas	36	50
Western Systems[a]	21	27
Reserve Margin U.S.	27	37

[a] U.S. portion of the pool.

SOURCE: National Electric Reliability Council. Adequacy *of Power Supply Winter 1980/81 and Summer 1980.*

Table 73.—Private Utility Return on Equity

	Average authorized return	Estimated return
1970	·	11.80/0
1976	12.8%	11.5?40
1980 (estimate)	14.20/o	11.00/0

SOURCE: Edison Electric Institute. Statement at FERC Conference on the Financial Condition of the Electric Utility Industry In the United States, March 1981, tables 15 and 3.

Experience of Each Utility is Different. Utilities differ in the extent to which they have had to cope with the problems described above. Some utilities such as Ohio Edison are experiencing slow growth in demand and generate most of their electricity with coal. Others such as Florida Power & Light must cope with both the price pressures caused by heavy dependence on fuel oil to generate electricity and with the pressure of an annual growth rate in sales of more than 4 percent. Particular utilities faced with angry customers because of rapid increases in electricity rates, stagnant growth in electricity sales or financially threatening capital requirements for new generating capacity may consider developing an energy management program as one response to these problems. The problems and opportunities of such programs for each of these reasons is described below, after the discussion of publicly owned systems.

Federal Power Marketing Agencies and Publicly Owned Systems

Public power is much more important in some parts of the country than in others.

Six Federal power marketing agencies (see table 74) own about 9 percent of all the installed generating capacity in the United States, With a total system capacity of almost 30,000 MW, TVA, established in 1933, is the largest of these and the largest single electric utility in the country. About 65 percent of TVA's sales are at wholesale to municipal utilities and rural electric co-ops. The remainder is sold to private industries, other Federal agencies, and private power companies. The Bonneville Power Ad-

Table 74.—Publicly and Privately Owned Systems Within the U.S. Electric Power System, 1979

Type of system	Number of systems	Installed capacity Thousand MW	Percent
Privately-owned	218	446	79%
Local public systems	2,206	56	10
Federal power agencies	6	52	9
Rural electric cooperatives	916	17	3
Total		571	1000/0

NOTE: Percent column does not add to 100 due to rounding,
SOURCE. "Public Power Directory," *Public Power,* January-February 1981

ministration was created by the Bonneville Project Act of 1937 and markets power from 30 hydroelectric projects constructed by the Army Corps of Engineers and the Bureau of Reclamation constructed in the Columbia River Basin. It also sells power wholesale to publicly owned systems i n the Northwest.[13]

The more than 2,000 local publicly owned systems own less than 10 percent of the generating capacity in the country. They include city-owned systems (municipal utilities), country-owned systems and a few State-owned systems such as the Power Authority of the State of New York (PASNY) which operates more than 9,000 MW of capacity for resale to municipalities, private utilities and industrial customers in New York and neighboring States.

About 44 cities with more than 50,000 population own their own electric utilities (see table 75), Many of these purchase power from the TVA (Memphis, Nashville, Knoxville) and others from the Bonneville Power Administration (Seattle, Tacoma). There are several large municipal utilities in Texas (San Antonio, Austin), in Florida (Gainesville, Jacksonville), and in California (Los Angeles, Palo Alto, Santa Clara County). In all fewer than 100 municipal utilities experience more than 100 MW in peak demand. The number of municipal utilities has remained stable over the last two decades. Recent efforts to establish publicly owned systems in Oregon and New York State have been vigorously opposed by private utilities, and generally defeated. One small city, Messina, in upstate New York has succeeded in establishing a municipal utility after protracted legal battles.

Both Federal power systems and municipal utilities (as well as State and county-owned systems) have some advantages over privately owned utilities. As public entities they do not pay taxes and they raise money in the tax-free bond market. Thus their financing costs are significantly less than the costs of private systems. TVA is projecting 9.5-percent interest rates on its bonds for the 1980's compared to new private utility bond interest rates of 14 percent.[14] Federal power marketing systems set their own rates. The rates of municipal systems are approved by the local city government. State public utility commissions have no jurisdiction over municipal utility sales within city limits. In some cities such as Seattle, Wash., the local city government exerts considerable control over the public utility. More commonly, the municipal utility operates fairly independently of the city government. San Antonio's municipal utility has an independent board appointed to serve the interests of the holders of the debentures issued for the original capital of the system. The mayor of San Antonio meets with the Board ex-officio and the rates are approved by the city council.[15]

publicly owned systems have had to deal with many of the problems confronted by privately owned systems in the 1970's; increasing cost of new generating capacity, increasing interest rates, and customers angry at rate increases. A few public systems have responded with energetic conservation programs; TVA (described in box N) and Seattle City Light. Others have stuck to more traditional responses of adjusting and managing traditional powerplant construction programs.

[13]This section is drawn from background information on publicly owned utilities in the forthcoming OTA report on *Cogeneration*.

[14]Sansom, op. cit., and Edison Electric Institute, op. cit.

[15]See description in the San Antonio Case Study in ch. 10.

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Table 75.–Municipal Utility Systems Serving Cities With Populations Over 50,000

Municipal utility	1978 peak demand (kW)
Alabama	
Huntsville Utilities	*525,000*
Arkansas	
North Little Rock Electric	156,942
California	
Anaheim Electric	*388,800*
Burbank Public Service	197,000
Glendale Public Service	194,500
Hetch Hetchy Water and Power (San Francisco)	456,000
Los Angeles Department of Water and Power	—
Palo Alto Electric	143,793
Pasadena Water and Power	175,000
Riverside Public Utility	277,920
Sacramento Municipal Utility	1,577,785
Santa Clara Electric	193,872
Colorado	
Colorado Springs Department of Public Utilities	294,000
Florida	
Gainesville-Alachua Co. Regional Electric	179,400
Jacksonville Electric	1,253,000
Orlando Utility	459,000
Tallahassee Electric Department	256,000
Georgia	
Albany Water, Gas and Light	140,255
Illinois	
Springfield Water, Light and Power	310,000
Indiana	
Anderson Municipal Light and Power	106,800
Kansas	
Kansas City Board of Public Utilities	428,400
Kentucky	
Owensboro Municipal Utility	129,600
Louisiana	
Lafayette Utilities System	187,000
Monroe Utility Commission	—
Michigan	
Detroit Public Lighting	115,000
Lansing Board of Water and Light	391,000
Minnesota	
Rochester Public Utility	112,600
Missouri	
Columbia Water and Light	114,000
Independence Water and Light	187,700
Springfield Cities Utilities	338,000
Nebraska	
Lincoln Electric System	369,057
North Carolina	
Fayetteville Public Works	263,200
Ohio	
Cleveland Division of Light and Power	105,000
Oregon	
Eugene Water and Electric	482,600
Tennessee	
Chattanooga Electric Power Board	—
Clarksville Department of Electricity	140,220
Knoxville Utilities Board	1,011,571
Memphis Light, Gas and Water	2,074,342
Nashville Electric Service	1,612,132
Texas	
Austin Electric Department	763,000
Garland Electric Department	285,000
Lubbock Power and Light	135,500
San Antonio Public Service	1,688,000
Washington	
Seattle Department of Lighting	1,644,000
Tacoma Public Utilities, Light Division	825,573

SOURCES: Electrical World, *Directory of Electric Utilities, 1979-1980*, McGraw Hill, Inc., 1979; Electrical World, Electric *Utilities of the United States* (map), McGraw Hill, Inc., 1977; U.S. Department of Commerce, Bureau of Census, *County* arrd *City Data Book, A Statistical Abstract Supplement, 7977* (Washington, D. C.: U.S. Government Printing Office, 1978).

Box N.—TVA Home Insulation Program—Audits and Finance to Reduce Demand

In 1977, TVA launched a major program—called the Home Insulation Programs (HIP)—to provide free audits, interest-free loans, and followup evaluation to residential customers throughout the system. The program was developed to reduce present and future demand for electricity by encouraging more efficient use. TVA set a goal of fully weatherizing 145,000 homes by 1986. As of the fall of 1981, it had completed 490,000 audits and made 210,000 loans.[1]

The basic HIP approach has three components:

1. All residential customers, regardless of the type of fuel used are eligible for a free home energy survey.
2. Customers in electrically heated or cooled homes are eligible for an interest-free loan that covers material and labor costs, up to $2,000, for weatherization.
3. When work is completed, TVA reinspects the retrofit to ensure that it conforms to TVA specifications. Payment is not made until TVA certifies that the work conforms to utility standards.

The goal of the HIP is to yield an annual energy savings of 2.5 billion kwh and to save about 1,100 MW of peak electric demand by 1990, at a total estimated program cost of $126 million.[2] TVA's 2.5 million residential customers (served by 160 distributors) account for 33 percent of the system's output. Forty-five percent of the system's residential customers use electric space heat.

According to an evaluation performed for TVA in the spring of 1980 by ICF Inc., HIP had already substantially benefited both customers and management. ICF found that the average $310 investment made by participants was recovered within 4 years in reduced utility bills.[3] ICF estimated that the program had had a substantial cumulative effect on the demand for TVA power, According to the evaluation, the first 27,000 participants would realize combined annual energy savings of 50.5 million kWh, or a total of 758 million kWh over a useful insulation life of 15 years.[4]

Although other utilities offer audits with financing, TVA has an unusual combination of aggressive marketing, interest-free financing, and quality control through reinspection of retrofit work. By September 1981, audits under HIP had been conducted of almost 20 percent of the 2.5 million consumers in the TVA service area.

At first TVA had trouble reaching low-income households. In October 1980, TVA officials reported that only 5.2 percent of the participants in the HIP came from households with incomes of less than $5,000 even though these were more than 20 percent of the customer households. By the fall of 1981, TVA had made notable progress. Nearly 40 percent of all households participating in the program were low income. TVA also had some initial difficulty reaching renters which in 1980 were less than 7 percent of all households surveyed. TVA officials launched a concentrated campaign to persuade landlords to have their buildings surveyed and retrofit. The effort met with some success. As of September 1981, 84,500 rental units had been surveyed. TVA has provided window stickers to those apartment owners who implement the suggested weatherization measures.[5]

TVA also launched two other specific programs designed to assist low-income households. One of these is the Warm Room Project which will allow customers to finance insulation for one room or area of their homes which they will use most during the winter months, In a second project to benefit low-income people, TVA has set a goal of weatherizing all of an estimated 30,000 electrically heated public housing units in its service area within 2 years. In cases when weatherization funds are not available to public housing authorities, TVA's no-interest loans will be used. As of September 1981,33,199 units had been surveyed and 2,039 insulated.[6]

While HIP is the most prominent component of the TVA program it is not the only one. The utility also offers lo-year loans for heat pumps at a moderate interest rate pegged at TVA's average cost of borrowing (14 percent in 1981). TVA estimates that in the average home a heat pump could save 4,000 to 7,000 kWh a season or $180 to $322 a year. The number of homes readhed by the program is impressive. As of September 1981, TVA had made about 24,500 heat pump recommendations and 12,200 installations, and had loaned about $40 million. Under a similar program to finance solar hot water heaters, 8,400 surveys had been conducted and almost 2,000 systems installed.[7]

TVA has also extended its audit and financing approach to the approximately 300,000 commercial and industrial customers served by its distributors. A walk-through survey is available at no charge for customers whose facilities can be analyzed in approximately an 8-hour period. TVA will also reimburse the cost of a more extensive and complex survey if the customer implements electricity-saving measures which achieve 75 percent of the estimated dollar savings possible. As of September 1981, about 6,000 commercial and industrial buildings had been surveyed. TVA will also make loans for up to 10 years at its average borrowing rate of 14 percent, but as of September 1981, less than 40 customers had obtained these loans.[8]

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[1]Tennessee Valley Authority, Office of Power, Division of Energy Conservation and Rates, Program *Summary, October* 1981.

[2]TVA, op. cit., p. 1.

[3]ICF, Inc., *The TVA Home Insulation Program: An Evaluation of Early Program Impact,* April 1980, PP. vi-vii.

[4]ICF, op. cit., p. vii.

[5]Robert F. Hemphill and Ronald L. Ownens, "Burden Allocation and Electric Utility Rate Structures: Issues and Options in the TVA Region," unpublished paper, October 1980, p. 6; Deborah R. Both, Robert Dubinsky, and Sue Bodilly, A Description *of Integrated Retrofit Delivery* Systems *and Innovative* Conservation Programs *in Selected Localities,* The Rand Corp., March 1981 (N-1673-DOE); TVA, op. cit., pp. 1-2, 8.

[6]TVA, op. cit., pp. 7-8.

[7]TVA, op. cit., pp. 4-5, 17-18.

[8]TVA, op. cit., pp. 12-13.

VARIETIES OF ENERGY CONSERVATION PROGRAMS

The following sections in the chapter describe the characteristics of energy management programs undertaken for any of four reasons:

- improve customer relations;
- earn profits i n unregulated subsidiaries;
- earn profits for gas companies within a regulated framework; and
- permit postponing of electric generating plant construction.

Energy Conservation Programs Primarily for Public Relations Purposes in Gas and Electric Utilities

Many gas and electric companies have developed low-volume audit programs in the last few years. **A** few have developed high-volume programs for more than public relations value, as discussed below. The Tampa Electric Co. developed an energy audit program in September 1978. **The purpose of the program was partly to gain experience with a program before being required to have one by the Federal Government and partly to promote good relations with utility customers. Only if, in the very long term, a conservation ethic developed among its customers, did Tampa Electric expect the audit program to have an impact on the utility's demand** for electricity.[16] Northern States Power launched a similar program in 1976 to help its gas customers cope with skyrocketing gas costs. in all about 65 investor-owned utilities had audit programs as of the winter of 1977-78 before the Federal utility audit program (RCS) was anoouced. [17]

Of these most are low-volume programs which are not explicitly tied to major reductions in requirements for generating capacity although the utility may express an expectation that the program will affect growth in peak demand over the long run, The resources devoted to these programs are limited (compared to large-volume programs discussed below) and the numbers of audits performed each year is also fairly small, not likely to have a major impact on building retrofit. Table 76 shows four moderate-volume audit programs assessed for a DOE study. The largest volume program of the four–Niagara Mohawk–had done about 3,300 audits in a single year. Such programs do not market as aggressively to prospective customers as a more goal-oriented program might. Virtually all such programs offer audits primarily to single family residential customers.

[16] *Electric and Gas Utility Marketing of Residential Energy Conservation:* Case *Studies*, May 1980, Booz Allen for the Department of Energy.

[17] Unpublished survey data compiled by staff of Residential Conservation Office, DOE, September 1981.

Energy Conservation Programs Launched by Utilities To Earn Money as Unregulated Subsidiaries

Reduced earnings and projections of slow growth or decline in the demand for electricity and gas have led some gas and electric utilities to consider diversifying into aspects of the energy conservation business in order to have an entry into an enterprise with a potential for growth.

Electric utilities and gas distribution companies have been diversifying into other businesses over the past few years. The desire on the part of utility executives to put capital to work in less regulated businesses (as well as assure a secure supply of fuel) has led to significant investment in such areas as oil and gas exploration and coal mining. Many of the companies have created holding companies with new names and new subsidiaries to pursue these interests.

Several companies (Boston Gas and Washington Natural Gas, among others) have recently attempted to market energy-efficient appliances or conservation devices. These efforts have met with mixed results. There are several major problems that utilities face when trying to enter these markets:

- They do not have distribution channels outside their service areas and therefore cannot gain some of the benefits of economies of scale that their competitors have.

Table 76.—Audits per Year Performed by Selected Utilities

	Audits per year	Audit staff	Financing
Utilities with moderate volume audit programs (time period covered)			
Arizona Public Service (summer 1977-December 1978)	About 1,800	11	
Niagara Mohawk (June 1978-summer 1979)	About 3,300 onsite	50	9.5 percent
Northern States Power (December 1977 -July 1979)	About 3,000	5	Available to some customers at 9 percent
Tampa Electric Co. (September 1978-October 1979)	About 2,000	4	None
Utilities with large volume audit programs (time period covered)			
Public Service Colorado	35,000 attics insulated 4,500 audits (in 6 months)	20 full time; 50 equivalent; 100 auditors, part-time	
Pacific Power & Light (October 1978-summer 1979)	11.000	150 auditors; 15 post installation inspectors 60-70 percent of their time	10,000 zero interest loans
Pacific Gas & Electric Attic insulation program (1978).	4,922 attic inspections; 4,500 attic installations	135 (75 of these are energy auditors)	
Audit Program (January-September 1979)	20,000		5,422 6 percent low interest loans
NEESPLANS goals 1982 and beyond			
Residential	16,000 for 5 years	37	
Commercial	9,000	42	
Industrial	1,750	21	

SOURCES: May 1980 report by Booz Allen Hamilton, prepared for DOE under contract No. ET-78-C-01-3356, *Electric and Gas Utility Marketing of Residential Energy Conservation*; NEESPLAN, New England Electric System, October 1979; and the Office of Technology Assessment.

- Their lack of marketing expertise cannot be overcome simply by hiring a manager from a marketing-oriented firm. The entire utility management needs to become marketing oriented.
- Unless they can contribute something of value to the product (lower cost of production, improved performance, or economies of distribution) they cannot compete effectively with the other manufacturers.

For example, Boston Gas Co. recently attempted to market a water temperature thermostat to its customers. Their sales volume never exceeded 5,000 units per year in a service territory of over 200,000 customers, They sold the product to a private firm that is now selling about 2,500 units per month. [18]

[18] Interview for OTA by Temple Barker Sloane, Inc., with president of Boston Gas Co.

Utilities may eventually become successful at marketing conservation equipment, but a new management orientation, special technical and marketing expertise, and broader distribution channels will be required. In a survey conducted by Booz Allen & Hamilton for the Edison Electric Institute only 4 out of 24 electric and combined gas and electric utilities identified profit potential in energy management ventures. Most utility executives interviewed viewed the residential energy management sector as highly competitive. Certain advanced conservation technologies and solar devices have growth potential as businesses but are still considered to pose significant business risk—of poor customer acceptance, poor reliability and/or unstable sales costs, Some of these same utility executives believed that "energy ventures targeted at the industrial sector . . . may offer more attractive profit opportunities than residential market programs."19

Although most executives interviewed felt that the most important factor is the strategic fit of energy ventures with existing utility expertise, they did cite other potential obstacles to developing such programs.

Protecting returns from regulation. The risks are still significant enough in energy management business ventures that utilities are willing to enter them only if they can earn more than the 11 to 12 percent regulated return. This can be done under any of a number of legal frameworks: an unregulated subsidiary, an unregulated affiliate or a joint venture with another company. In some States, however, utilities are faced with the possibility that utility regulatory commissions will take into account the unregulated profits in determining cost allocations or rate of return on the regulated activities.[20]

Antitrust. Many utilities expect smaller installers and competitors in the energy management business to claim unfair competition from utilities because of the utilities' opportunity to subsidize its energy management operations from its other operations.[21] (See later discussion of this point from the perspective of competing businesses.)

The utilities' access to its service mailing lists, service network, and reputation for reliability may also be cited as unfair advantages resulting from its monopoly franchise. In order to avoid some of these issues some utilities reported to Booz Allen that they plan to avoid the use of their customer mailing lists and to encourage a host of competitors in the marketplace.

Public Utility Holding Company Act. This act (passed in 1935 to prevent pyramiding of holding companies involving utilities) requires that the Securities and Exchange Commission approve all investments by utility holding companies in businesses not directly related to the sale of electricity. There are 12 electric utility holding companies that are subject to the act because they own more than 10 percent of a public utility company. Companies that operate intrastate are exempted from the act. Some companies that are not currently classified as holding companies are concerned that they may be so classified if they make investments outside of the narrow definition of their business.

Gas Utility Company Profits From Energy Conservation Programs

Gas distribution companies buy gas on contract from pipelines and occasionally from liquefied natural gas (LNG) shipping companies. They may own and operate small natural gas wells in their areas, as does People's Gas of western New York, but on the whole the only capital assets they must invest in are gas distribution systems. Unlike electric utilities, they have no reason or opportunity to compare "investment" in energy conservation with investment in other capital plant.

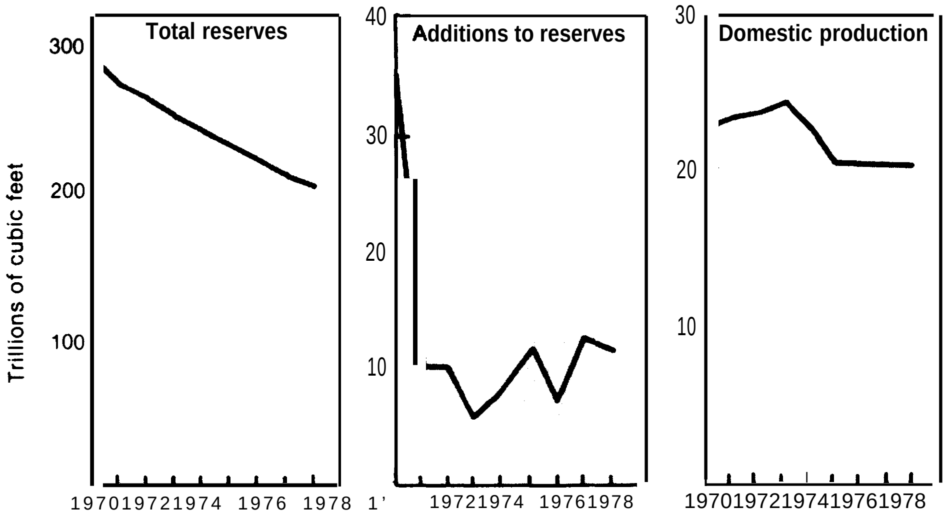
While gas distribution companies may have strong motivation to develop energy conservation programs for public relations purposes or in order to earn profits in an unregulated subsidiary (as described above), it is not so clear what incentive gas distribution companies have to earn money from conservation within a regulation framework.

Gas utility executives are primarily concerned about the continued availability of their product. Although short-term supplies of natural gas are generally considered adequate, there is widespread disagreement about the long-term outlook. The United States has consumed natural gas at a rate of about 20 trillion ft^3 (Tcf) per year over the past 5 years. Its existing domestic supply is estimated at 200 Tcf. Supplies have only grown at an annual rate of about 10 Tcf in recent years (see fig. 54), However, drilling and exploration efforts are up dramatically. Hughes Tool Co. predicts that in 1980 about 60,000 wells will be completed, about double the number completed in 1973.22 As a result, additions to supply in 1980 are expected to reach 15 Tcf.

[19] The source for this whole section is Booz Allen, *Investor-Owned Utility Business Prospects and Problems* in Energy *Management*, progress report to the Edison Electric Institute, Nov. 5, 1980.
[20] Booz Allen, op. cit., p. 22 ff.
[21] Booz Allen, op. cit., p. 23 ff.

[22] *Oil and Gas Journal*, Jan. 18, 1980.

Figure 54.—Trends in U.S. Natural Gas Supplies



SOURCE: Energy Information Administration, *Annual Report to* Congress *1979*, VOl 11, 1979, tables 16 and 37

industry optimists expect these wells and supplies from Mexico, Alaska, and Canada will be supplemented by synthetic gas, liquefied natural gas from Algeria and Indonesia, and gas from tight sand formations. Industry pessimists are concerned that the current gas bubble has been created by a temporary decline in demand, particularly by industrial users, and that new forms of gas supply may not be sufficient to meet increased demand in the 1980's. Conservation by their customers, however, can leave gas companies with additional gas supplies. In theory, gas distribution companies with supplies in excess of customer demands have the opportunity to sell that gas to other gas distribution companies for resale. Currently, in some companies, the price of this gas is pegged to the price of low sulfur residual fuel oil, or the equivalent of about $5/Mcf. This is generally a higher price than the marginal gas that would be displaced by conservation. Conservation by existing customers would increase the amount of gas available for sale in the markets. As long as the price exceeds the prices of the last block of gas conserved, conservation will remain profitable.

For some gas companies, the hookup of new residential customers to existing distribution lines can be profitable. The hookup of new customers allows the utility to sell gas that would have been sold under the last block of a declining block structure to new customers at a higher price. One gas company estimates that they earn a $260 per year return on a fuel oil-to-gas furnace conversion that costs $125, for an approximate 200-percent return on investment.[23] For such resale to be profitable, however, gas conservation must be by those large users paying the lowest block rates, generally industrial and large commercial customers.

There is another variation of this method of making money off conservation, in gas utilities with "lifeline" rates. These are low rates allowed to residential customers for the first block of gas they consume. Subsequent gas consumption is paid for at increasingly higher rates. In theory, gas companies could encourage conservation among customers using less than their lifeline block and sell this gas to industrial or other large customers paying the highest rate.

None of these three ways of making money off conservation within a regulated framework is very profitable. Given the longer range uncertainty of gas supplies, none provides the basis for a solid multiyear program for a gas utility company. No companies have announced programs to earn (or save) money on this basis. At best these sources of profit could be fortunate

[23] Interview for OTA by Temple Barker Sloane Co. with gas company executive.

byproducts of energy **conservation programs launched** for other reasons, improving customer relations or compliance with a State regulatory order.

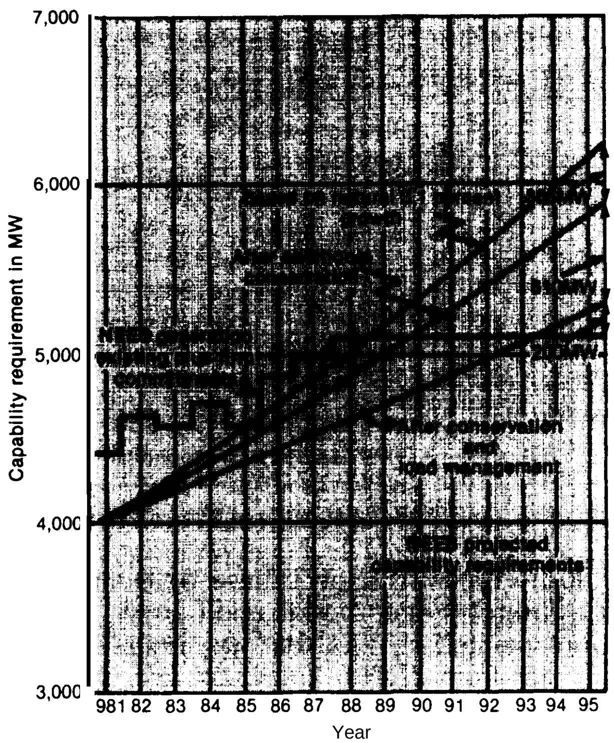
Electric Utility Conservation Programs To Permit Postponement or Curtailment of Plans To Build New Generating Capacity

Many electric utilities express the hope that their low-level energy conservation programs will contribute to slower growth in electricity demand, particularly demand for peak capacity. **A** few utilities, however, have announced explicit plans to launch ambitious conservation programs and tied these to explicit reductions in the need for new generating capacity.

The New England Electric System (NEES), for example, announced in its NEESPLAN of October 1979 a conservation program for commercial and residential customers to save **300 MW of** peak demand and several different time-of-day pricing and load management programs to save another 500 MW of winter and summer peak demand.[24] This plan would allow NEES to meet its projected 1995 demand almost completely with the powerplants under construction or firmly committed through 1987, as shown in figure 55. Continued growth in demand, without aggressive conservation and load management would require almost 1,000 MW more capacity in 1995. NEES expects to spend about $100 million in capital costs (constant 1979 dollars) and about $10 million additional operating costs to carry out the load management and conservation program.[25]

If successful in reducing its generating requirements, the company expects to save about **$255 million in capital** costs for new generating capacity.[26] The load management program is not expected to result in loss of electricity sales and revenues; rather it is intended to shift more electric demand offpeak and therefore increase the capacity utilization ratio,

Figure 55.—NEESPLAN Projections of Demand and Generating Capacity Requirements, 1981-95



SOURCE: NEESPLAN, New England Electric System, October 1979.

Other companies may follow the lead of NEES. Indeed, General Public Utilities following the bleak prospects for raising new capital in the wake of the Three Mile Island accident, announced such a plan. Pacific Power & Light and several California utilities have large volume programs described in table 76. The challenge and difficulty of launching such a program, however, must not be underestimated.

The program must be big enough to permit the postponement or cancellation of all or most of a powerplant. Figure 55 from NEESPLAN illustrates the contrast between the stepwise planning for powerplant construction and the gradual increase in electricity demand, Since powerplants must be planned 7 to 10 years before they are needed, only a significant change in demand can be counted on that far in

[24] NEESPLAN, October 1979, New England Electric System, pp. 8 and 9. Because of reserve requirements these reductions in peak demand translate into reductions in peak capacity of **350** and 600 MW respectively.

[25] Ibid., pp. 18-19.

[26] The full capital cost savings are higher but they are adjusted downward for higher fuel costs resulting from rising oil generating plants rather than new coal or nuclear plants.

advance. Conservation and load management must together provide at least 100 to 300 MW of reduction in capacity before they are big enough to be explicitly taken into account in planning for new capacity.

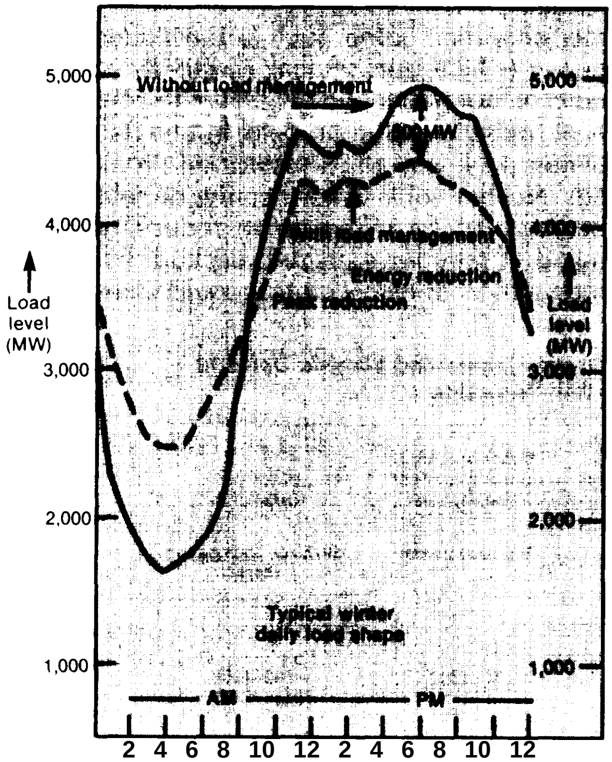
The planning for conservation and load management must take into account the specific contribution of different devices to reduction in peak demand. Table 77 lists several devices including some of those proposed for the NEES program (such as radio and ripple control and storage water heaters.) Some, such as those affecting hot water heating, can be expected to reduce the daily peak wherever it occurs, summer or winter. Some, such as the storage space heater (which uses offpeak electricity to heat a tank of hot water which then provides space heat during daytime on peak hours) reduce the winter peak (see NEESPLAN/Load Profile in fig. 56). Neither solar water heating or solar space heating can be relied on to reduce peak demand (if they have electric backup) because a long period of heavy clouds could cause build-

Table 77.—Potential Impact on Capacity Requirements and Electric Demand of Different Conservation Programs

Energy management program	Utility control ?	Estimated number of installations for 100 MW reduction in peak demand	Impact on energy consumption per installation	Cost per installation
Measures to reduce daily peaks				
Storage water heater.	No	80-1 20,000[d]	Small increase	$975 for 150[k] gallon tank
Interlock (prevents water heater, stove, clothes dryer and refrigerator from operating simultaneously)	No	59,000f	Minimal	**$90-125**[n]
Water heater time switch	Yes	91,000[c]	Minimal	**$130-240**[i,j]
Radio and ripple control (cycles water heater, air conditioner)	Yes	71,000[a] (water heaters)	Minimal	Radio 95-$1089
				Ripple $100-115h
		(air conditioners)		
Measures to reduce winter peak				
Storage space heater	No	**7-100,000**[e]	Small increase	$1,000-5,000 [1,m]
Measures to reduce summer peak				
Heat pump hot water heater	No	Not estimated	50-75 percent reduction in water heating energy	$400 -800[q] for single-family house
Heat recovery from air-conditioners.	No	Not estimated	Substantial reduction (not estimated)	$400 -800[q] for single-family house
Measures to reduce energy consumption with uncertain impact on peak				
Solar water heating	No	No systematic impact	25-50 percent reduction in water heating energy	$1,500-3,2000
Solar space heating	No	No systematic impact	25-50 percent reduction in space heating energy	$4,800[p]

a John Schaefer, *Equipment for Load Management*, 1979. Based on experience or Detroit Edison and Buckeye Power.
b Schaefer Based on experience of Arkansas Power & Light, Mississippi power & Light, and Cobb EMC.
c Schaefer, Based on experiences of Kentucky Utilities (upper element functioning at all times).
d Argonne National Laboratory, *Assessment of Energy Storage Technologies and Systems*, 1976. Based on computer simulation.
e Argonne National Laboratory.
f Schaefer, Based on Ohio Edison's experience with interlocks.
g Schaefer. Based on 40,000 end-points.
h Based on interview with manufacturer.
i Schaefer. Based on experiences at Kentucky Utilities.
j General Electric Timeswitch Meter Prices,
k Based on interview with manufacturer. Does not include installation.
l Argonne National Laboratory Central furnace.
m Argonne National Laboratory. Baseboard system.
n Based on interview with manufacturer.
O U.S. Department of Housing and Urban Development, *Hot Water from the Sun*, 1980.
P Arthur D. Little, System Definition Study - phase 1, 1977, Costs included 200 tt² collector, water heater, solar subsystem, and auxiliary resistance heater.
q Arthur D, Little, Assessment Of *the Potential for Heat Recovery* and Load *Leveling* on *Refrigeration Systems, 1980.*

Figure 56.— NEESPLAN Projected Load Profile, 1980-95



SOURCE: NEESPLAN, New England Electric System, October 1979.

ings equipped with solar heaters to place full demands on the electric system.

It takes thousands of installations on customers' properties to equal a single small powerp/ant. Table 77 reports on estimates of the number of installations of various conservation and load management devices to equal a 100-MW reduction: 80,000 to 120,000 storage water heaters, 93,000 radio or ripple controls on airconditioners, NEESPLAN calls for a total of 173,000 audits over the 10-year **life** of its conservation program, and 350,000 installations of time-of-use meters and radio/ripple receivers for its load management program, [27] The utility must establish entirely new relationships with thousands of customers. This not only requires money and manpower (NEES projects requirements for full-time audit staff of 100) but it requires the ability to convince thousands of customers that **such** a move is in their best interests.

[27] NEESPLAN, op. cit., p. 19.

For several of the NEESPLAN load management devices, customer acceptance will only be forthcoming if NEES and the regulatory commissions in the three States—Massachusetts, Rhode Island, and New Hampshire—require time-of-use rates so that the customer will be penalized for using onpeak electricity.

Measured data is scanty on actual electricity demand with these devices. For this reason, NEESPLAN includes several years of installing and monitoring pilot versions of each program. NEES has some time to do this. It will not have to start planning additional powerplants until 1984 or 1985. By that time, it should be clear if customers will accept the conservation program and load management devices and what the actual impact will be on peak electricity demand and on kilowatt hours.

Incentives to Other Utilities. Many other utilities whose characteristics are **shown** in table 78 might have reason to launch ambitious conservation programs, Some have very tight reserve margins; some have large shares of residential customers and winter peaks; some have large shares of commercial customers who might be willing to install load management devices. It is clear from the description of NE ESPLAN, however, that entering such uncharted territory with such demanding requirements for success with large numbers of customers may, at this stage, prove a management challenge far greater than the construction of a single small powerplant which such programs would replace.

Consumer Perspective on Utility Conservation Programs

As utilities have begun to launch substantial conservation programs, there have been challenges to utilities from consumer groups concerned that ratepayers will end up paying for conservation programs from which conservation clients will benefit far more than ratepayers. One such group in California, called Toward Utility Rate Normalization (TURN), challenged Pacific Gas & Electric's Zero interest Program (ZIP) conservation financing program on the grounds that it represented a subsidy of rate payers to participants. Participants in

Table 78.—Utility Characteristics That May Influence the Development of Conservation Programs

Region and name of utility	Electric and gas company	Oil and/or gas more than 40 percent of generating capacity (percent)	Planned capacity additions > 70 percent of existing capacity (percent)	Electricity > 40 percent of residential energy use in area W = winter peak (percent)	Commercial electricity > 30 percent of total load (percent)
1. New *England*					
Boston Edison	—	780/o	—		380/o
New England Electric (H)	—	58	N/A	(w)	N/A
Northeast Utilities (H)	X	45	N/A	(W)	—
Public Service of New Hampshire	—		1840/o	—	—
United Illuminating	—	93	—	—	—
II. New York/New Jersey					
Consolidated Edison	X	67	—	—	57
Long Island Lighting	X	N/A	81		—
Niagara Mohawk Power	X	N/A	98	(w)	—
Orange & Rock Utility	X	95	—	—	—
Public Service Electric & Gas	X	—	—		35
Rochester Gas and Electric	X	—	113	(w)	—
III. *Midatlantic*					
Baltimore Gas & Electric	X	—	—		—
Delmarva Power& Light	X	44	—	(W)	—
General Public Utility(H)	–	—	N/A	—	
Pennsylvania Power & Light	—	—	—	(W)	
Philadelphia Electric	X		—	—	
Potomac Electric Power	—		—	—	42
Virginia Electric & Power	X	—	—	—	—
Duquesne Light	—	—	—	—	30
IV. *South Atlantic*					
Carolina Power & Light	—	—	74	420/o	—
Duke Power	—	—	—	(W) 42	—
Florida Power & Light	—	74	—	(W) 61	34
Gulf State Utilities	X	N/A	—	—	—
Kentucky Utilities	—		106	—	—
Louisville Gas & Electric	X	N/A	106	—	—
Middle South Utility	—	73	N/A	—	—
South Carolina Electric & Gas	X	—		42	—
Tampa Electric	—	—	—	(W) 61	—
V. *Midwest*					
Cincinnati Gas & Electric	X	—	71		—
Cleveland Electric & Illuminating	—	—	—		—
Commonwealth Edison	—	—	—		30
Dayton Power & Light	X	—	—	(W)	—
Detroit Edison	—	—	—	—	—
Illinois Power	X	—	—	—	—
Northern Indiana Public Service	X	—	83	—	—
Northern States	X	—		—	—
Minnesota Power & Light	—	—	129	w)	—
Ohio Edison	—	—	—	(W)	—
Toledo Edison	X	—	—	(W)	—
Wisconsin Electric Power	—	—	—	—	—
VI. *Southwest*					
Houston Industries(H)	—	85	N/A	—	—
Oklahoma Gas & Electric	X	62	—	—	—
Southwestern Public Service	—	N/A	—	—	—
Texas Utilities	—	53	N/A	—	N/A
VII. *Central*					
Kansas City Power & Light	—	—	72	—	38

Table 78.—Utility Characteristics That May Influence the Development of Conservation Programs—Continued

Region and name of utility	Electric and gas company	Oil and/or gas more than 40 percent of generating capacity (percent)	Planned capacity additions > 70 percent of existing capacity (percent)	Electricity > 40 percent of residential energy use in area W = winter peak (percent)	Commercial electricity > 30 percent of total load (percent)
VIII. *North Central*					
Montana Dakota Utility	–	—	—	—	—
Public Service Colorado	*X*	—	104%	—	32%
Utah Power & Light	—	—	—	—	—
IX. *West*					
Arizona Public Service	X		185	44%	31
Pacific Gas & Electric	X	67%	90	—	36
San Diego Gas & Electric	X	94	—	—	—
Southern California Edison	—	74	—	—	—
Tucson Electric Power	—	—	—	44	—
X. *Northwest*					
Pacific Power & Light	—	N/A	—	(w) 54	—
Portland General Electric	—	—	134		—
Puget South Power& Light	–	—	344	(w) 50	—

(H) = Holding company.
' = Electricity imported from Canada

SOURCE: Detailed data presented in appendix table A.

PG&E's program are disproportionately moderate and upper income homeowners. Elderly persons and renters have participated in numbers far below their share of PG&E's customer base.[28] In its brief submitted for a court challenge to the program, TURN estimated that participants in the conservation program would receive a net gain of about $780 million (above costs) in utility bill savings while ratepayers would subsidize these benefits by about $550 million.[29] PG&E itself calculates that savings from deferred capacity will not exceed the costs of conservation programs until 14 years into the program for electricity and 17 years for gas.[30] The results cited above are highly sensitive to particular assumptions about rate structure and assumptions about the impact of conservation on consumption patterns and the need for new capacity. At the same time they illustrate the controversy surrounding the consumer impact of utility conservation programs.

Retrofit Business Perspective on Utility Conservation Programs

Solar and conservation retrofit businesses have raised the concern with Federal and State governments that utility conservation programs will be unfairly competitive with existing retrofit businesses, because the utility has monthly contact with its customers that it can use for marketing purposes and because customers may have confidence in a utility's work even when the utility has no track record in energy retrofit. Challenges of this sort led to regulations in the Residential Conservation Service (RCS) program–restricting utility auditors from installing any retrofit they recommend and requiring a very open process of utility referrals to retrofit cont ractors.

Conclusion

Utilities are very likely to continue launching energy conservation programs even if they are

[28] Citation from California PUC case No, 59537, included in a working paper to be published by OTA in conjunction with this study, Fostering *Equity in Urban Conservation; Utility Metering and Utility Financing,* Steven Ferrey & Associates, January 1981, pp. 65-67.
[29] Ferrey, op. cit., p. 69.
[30] California PUC case No. 59537, cited in Ferrey, *op.* cit., p. 69.

not required to by the Federal Government. Those audit programs launched primarily to maintain good customer relations (and also to foster a conservation climate) are likely to affect relatively small numbers of buildings each year, primarily single-family residences with fairly educated and fairly high-income owners.

Those programs launched to earn profits as unregulated subsidiaries, if successful, will have specific markets and purposes resulting from the need to compete successfully with nonutility businesses. These are unlikely to lead to large-scale general retrofit of city buildings and are very likely to be targeted on the commercial buildings, builders of new buildings, and upper income homeowners who have been the major clients of the existing energy management enterprises.

Few gas companies are likely to launch energy management programs to earn regulated profits per se although they may have such programs for good customer relations. A few electric utilities are likely to follow the lead of NEES and incorporate ambitious energy conservation and load management programs into their plans for new generating capacity. Such programs are likely to be aimed at commercial building owners except in those regions with heavy emphasis on residential electric heat. Until there is more experience with the marketing methods and technical results of these programs, however, the number of utilities which undertake them is likely to be very limited. They may have a major impact on certain kinds of city buildings in those few regions with these innovative utilities.

APPENDIX 8A.–ELECTRIC UTILITY STATISTICS

No.	Company name	Annual peak occurs' (kW)	Average residential rate[1] (cents/kWh)	Percent residential/ commercial load[2]	Residential electric energy' (percent)	Percent of generation': Coal	Oil	Gas	Nuclear	Hydro	Peak load/ total capacity	Nonfuel costs as a percent of total revenues'	Mw addition as a percent of existing Mw	Market-to-book ratio'	Joint electric and gas company
b 1	Allegheny Power	N.A.	4.00	N.A.	13	99	—	—		1	N.A.	N.A.	N.A.	66	—
2	Arizona Public Service	2,579,300 (s)	5.58	29/31	44	84	9	7		—	8	80	185	77	X
3	Baltimore Gas & Electric	3,621,000 (S)	4.95	34/18	25	27	12	3	55	3	25	66	66	69	X
4	Boston Edison .,	2,378,000 (S)	6.39	22/38	13	—	78	—	22	—	16	65	43	69	—
5	Carolina Power & Light	5,907,000 (S)	4.08	26/16	42	58	1	—	39	2	19	70	74	70	—
6	Cincinnati Gas & Electric	2,978,000 (S)	3.85	30/19	18	99	1	—	—	—	21	60	23	76	X
7	Cleveland Electric & Illuminating	3,233,000 (s)	5.48	23/21	18	82	3	—	15	—	29	66	53	76	—
8	Commonwealth Edison	13,804,000 (S)	5.11	28/30	16	50	8	2	40	—	27	70	71	68	—
9	Consolidated Edison	6,702,000 (s)	10.50	26157	13	—	57	10	33	—	29	77	20	53	X
10	Dayton Power & Light	2,105,000 (w)	4.55	35/19	18	N.A.	N.A.	N.A.	N.A.	N.A.	17	62	49	67	X
11	Delmarva Power& Light	2,289,300 (W)	5.90	24120	24	38	44	–	18	—	– 2	40	24	75	X
12	Detroit Edison	6,829,000 (S)	5.11	28/16	15	90	9	1	—	—	24	64	54	64	—
13	Duke Power	9,844,000 (w)	3.90	26/18	42	65	–	–	33	2	18	61	53	73	—
14	Duquesne Light	2,296,000 (s)	6.23	22/30	23	88	1	–	11	—	27	72	25	75	—
15	Florida Power & Light	9,732,000 (w)	4.66	51/34	61	–	57	17	26	—	11	67	21	77	—
b16	General Public Utilities. ,	N.A.	N.A.	N.A.	17	73	11	1	15	—	N.A.	N.A.	N.A.	21	—
17	Gulf States Utilities	5,229,300 (S)	3.90	19/13	31	N.A.	N.A.	N.A.	N.A.	N.A.	12	53	54	71	X
18	Houston Industries	N.A.	N.A.	N.A.	31	15	–	85	—	—	N.A.	N.A.	N.A.	79	—
19	Illinois Power.	3,019,214 (S)	4.29	28/18	16	96	3	1	—		24	55	48	84	X
20	Kansas City Power & Light	1,964,000 (S)	5.37	29/38	19	93	4	3	—	—	23	76	72	67	—
21	Kentucky Utilities	1,967,000 (s)	3.90	26/15	18	99	—	—	—	1	13	61	106	73	—
22	Long Island Lighting.	2,919,000 (s)	7.20	4215	13	N.A.	N.A.	N.A.	N.A.	N.A.	28	66	81	77	X
23	Louisville Gas & Electric.	1,752,000 (S)	3.66	30/22	18	N.A.	N.A.	N.A.	N.A.	N.A.	30	58	106	74	X
b24	Middle South Utility	N.A.	N.A.	N.A.	32	7	29	44	20	—	N.A.	N.A.	N.A.	68	—
25	Minnesota Power & Light	1,272,277 (W)	5.08	8/6	14	81	5	–		14	–52	86	129	79	—
26	Montana Dakota Utility	N.A.	N.A.	44127	19	98	1	1		—	16	80	0	103	—
b27	New England Electric	3,183,000 (w)	6.02	N.A.	13	20	58	–	14	8	18	N.A.	N.A.	77	—
28	Niagara Mohawk Power	5,641,000 (W)	4.35	25/29		N.A.	N.A.	N.A.	N.A.	N.A.	–18	69	98	69	X
b29	Northeast Utilties ,	3,955,200 (W)	5.20	N.A.	20	–	45	–	51	4	36	N.A.	N.A.	62	X
30	Northern Indiana Public Service	2,243,650 (S)	5.45	16/3	17	99	1	—	—	—	28	72	83	62	X
31	Northern States.	N.A.	N.A.	25/12	14	54	1	—	42	3	N.A.	81	21	79	X
32	Ohio Edison	3,556,000 (W)	5.39	30/21	18	94	2	—	4	—	27	68	0	81	—
33	Oklahoma Gas & Electric.	3,630,000 (S)	3.60	28/16	25	38	–	62	—	—	28	47	67	79	—
34	Orange and Rock utility	662,000 (S)	8.50	20/14	13	—	55	40	—	5	36	66	51	71	X
35	Pacific Gas & Electric.	13,215,200 (S)	3.54	33/36	31	—	28	39	—	23a	– 19	63	90	71	X
36	Pacific Power & Light	4,084,000 (w)	2.55	29/20	54	N.A.	N.A.	N.A.	N.A	N.A.	– 3	87	0	90	—
37	Pennsylvania Power & Light	4,427,000 (W)	4.24	36125	23	79	19	—	—	2	36	41	62	68	—
38	Philadelphia Electric .,	5,627,000 (s)	5.80	28/10	23	N.A.	N.A.	N.A.	N.A.	N.A.	27	73	25	69	X
39	Portland General Electric.	N.A.	2.78	40/26	54	14	6	1	50	29	N.A.	98	134	71	—
40	Potomac Electric Power	3,804,000 (S)	5.02	24142	25	85	15	–	—	—	24	52	0	77	—
41	Public Service Colorado	2,575,400	4.87	26/32	16	80	1	15	4	—	–1	69	104	75	X
42	Public Service Electric & Gas	6,736,000 (S)	7.00	26135	17	33	26	6	35	—	32	72	32	67	X
43	Public Service New Hampshire	1,152,000 (s)	5.78	31/11	15	83	1	16	—	—	24	72	184	67	—

No	Company name	Annual peak occurs' (kW)	Average residential rate[1] (cents/kWh)	Percent residential/ commercial load[2]	Residential electric energy[3] (percent)	Percent of generation[4] Coal	Oil	Gas	Nuclear	Hydro	Peak load/ total capacity	Nonfuel costs as a percent of total revenues[2]	Mw addition as a percent of existing Mw[6]	Market-to-book ratio'	Joint electric and gas company
44	Puget Sound Power & Light	3,109,400 (w)	2.00	47/21	50	14	10	—	2	74	7	95	344	67	—
45	Rochester Gas & Electric	950,000 (w)	4.60	26/22	13	32	16	—	49	3	10	76	113	62	X
46	San Diego Gas & Electric	2,019,000 (s)	5.30	39/20	31	—	74	20	6	—	17	50	0	77	X
47	South Carolina Electric & Gas	2,965,000 (s)	4.72	30/22	42	84	8	1	–	7	19	52	64	77	X
48	Southern California Edison	12,464,000 (s)	4.72	27/29	31		43	31	3	11	15	47	39	73	—
[b]49	Southern Company . . .	N.A.	N.A.	N.A.	32	80	1	1	12	6	N.A.	N.A.	N.A.	71	—
50	Southwestern Public Service	2,177,000 (s)	5.21	15/16	31	N.A.	N.A.	N.A.	N.A	N.A.	23	43	77	109	—
51	Tampa Electric	1,988,000 (W)	5.17	33/20	61	76	24	–	–	—	34	53	22	88	—
[b]52	Texas Utilities	N.A.	N.A.	N.A.	31	47	1	52	—	—	N.A.	N.A.	N.A.	80	—
53	Toledo Edison	1,395,000 (w)	5.87	25/16	18	69	1	–	30	—	16	76	0	69	X
54	Tucson Electric Power ., ...	1,247,000 (S)	5.85	19/17	44	69	11	20	—	—	16	66	13	88	—
55	Union Electric	5,557,100 (s)	4.37	27124	19	9	6 –	–	–	4	17	61	35	68	X
56	United Illuminating . .	911,300 (s)	6.23	36133	20	—	93	–	7		36	47	0	69	—
57	Utah Power & Light . .	2,723,000 (S)	4.28	19/14	20	93	1	3	–	3	–1	75	44	87	—
58	Virginia Electric & Power	7,929,000 (S)	5.14	33/25	37	36	27	–	35	2	14	61	34	57	X
59	Wisconsin Electric Power	3,313,000 (s)	4.40	30/25	17	58	2	3	35	2	19	73	67	73	—

[a]Fuel mix includes 10 percent geothermal
[b]Holding companies
NA = Information is not available

SOURCES
1 Electrical World, *Directory of Electric Utilities*, 1980-81 Edition, McGraw-Hill Publications Co., 1980.
2 Energy Data Report, *Statistics of Privately Owned Electric Utilities in the United States — 1978*, U S Department of Energy, October 1979.
3 DOE State Energy Data, April 1980. Electricity as a percent of all residential energy end-use.
4 Salomon Brothers, "Electric Utility Quality Measurements," 1980.
5. Calculated from Electrical World, 1 (peak load/total capacity).
6 Projected Mw was obtained from *Inventory of Power Plants* m *the United States — December 1979*, DOE, June 6, 1980, existing Mw was obtained from Energy Data Report (see footnote 2).
7 Salomon Brothers, "Electric Utility Common Stock Market Data," Nov 3, 1980.

APPENDIX 8B.–EFFECTS OF ISSUING STOCK AT DIFFERENT MARKET PRICES RELATIVE TO BOOK VALUES

The following cases illustrate the earnings per share consequences of issuing common stock at prices above and below book value. For simplicity, assume throughout that the rate of return allowed by regulators is 12 percent on the common equity base at the beginning of any year and that the dividend payout ratio b is 70 percent. Assuming for the moment that the industry or any given utility issues no stock, the industry's total earnings and dividends will grow at a rate which is 3.6 percent, A 12-percent return and a 30-percent retention of this amount (because dividends are 70 percent of earnings) means that the industry's common equity grows 3.6 percent per year, that earnings grow 3.6 percent because the percentage return on equity is constant, and that dividends grow at 3.6 percent (because the payout ratio is constant). There is a well known formula for stock prices in constant growth situations of this sort which can be written as:

$$P_0 = \frac{D_0}{K_e - g}$$

where:

P_o = stock price at time O relative to book value;

D. = dividends at time O relative to book value; and

K_e = investor's required rate of return on investment in stock of this risk class.

Dividends at time O can in turn be expressed as a fraction of book value as follows:

where:

$D_0 = E_0 \times b$; and

E_0 = earnings at time 0 relative to book value.

Earnings relative to book value can in turn be written simply as:

where:

$E_0 = r_e$

r_e = the allowed rate of return on equity

If the required rate of return is 10 or 15 percent, then the industry's market price relative to book value is 1.313 or **0.737, respectively. Given** that, we have assumed no new issues of common stock; these ratios hold on a per-share basis as well.

Consider what happens if the industry's capital expenditure requirements (or desires) are such as to necessitate (or prompt) the one-time issuance of common stock. For simplicity, first assume that investors either do not anticipate the issuance of common stock or do not react to its predictable consequences; this will simplify the calculations of the number of shares required to raise a given dollar amount of equity capital. The effect of correct anticipations will be discussed secondly. To make points clear, consider two illustrative cases. In the first, assume that investors are willing to settle for a 10-percent return for investing in the industry's common equity. In the second, perhaps either because the risks have increased or because inflation has shifted the general levels of nominal (current dollars) required rates of return upward, assume investors demand a 15-percent return. Also assume initially that the industry's need for common equity capital over time is just met by retained earnings in all years except one. As above, with the exception of the year of the stock issue, this means that required equity grows by 3.5 percent per year, and that earnings, earnings per share, and dividends per share grow at 3.6 percent per year.

Case 1.—If Allowed Returns on Equity Are Greater Than Investors' Required Rates of Return, Then Earnings per Share, Dividends per Share, and Market Prices Increase With Increasing Growth

Assumptions:

Initial equity. , ...	S_0 = $1,000,000
Allowed return on equity	r_e = 12%
Earnings	E_0 = $120,000
Payout ratio	b = 0,7'
Dividends	D. = b X E_0 = $84,000
Retained earnings as function of profit to common.	a = (1 – b) = .3
Growth in earnings and dividends.	g = a x r_e, = .036
Shares outstanding	n. = 100,000
Return required by investors	k_e = 10%
Market price.	$P_0 = \frac{D.}{(k_e - g)\ n.}$ = $13.42

The effect of the increased equity investment is to raise earnings, dividends, and market price per share by 2.2 percent. In this instance, because the preissue stock price did not reflect the opportunity to invest $100,000 at a rate of return above that demanded by the market, both the old shareholders and the new purchasers of stock received a $0.29 per share "windfall' gain.

If investors correctly anticipate the future need for common equity financing, then prefinancing prices will adjust so as **to** drive out the postfinancing windfall gain (or loss) to investors. In case 1, prefinancing prices reflect the capitalization of the expected postfinancing dividend stream at 10 percent, thereby boosting the prefinancing price upward and reducing the number of shares required to raise $100,000 in new capital. Thus, new investors purchase their shares at a price that holds their return on investment to 10 percent; the benefits of the industry's having an opportunity to invest at above-market returns all accrue to the original shareholders. of course, if after the date of purchase of the new shares the industry unexpectedly has yet another opportunity to invest equity over and above retained earnings at a favorable rate, the "new" investors would share in the second round of windfall gains. If both the first and second opportunity were correctly anticipated at the time of the first issue, however, the stock would have risen in market price so as to reflect all the benefits of both opportunities and to provide both the first and second rounds of new purchases with only their required return on investment.

Case 2.—if Allowed Returns on Equity Are Less Than Investors' Required Rates of Return, Then Earnings per Share, Dividends per Share, and Market Prices Decrease With Increasing Growth*

Assumptions:

Same as case 1 except:

$k_e = 15\%$

$$P_0 = \frac{D_0}{(k_e - g)\, n_0} = \$7.37$$

The market price an investor requiring a 15-percent return will pay for a $10 book value share is $7.37.

Suppose again that a sudden requirement for external equity financing of $100,000 arises too quickly for the market to anticipate and, hence, is financed at $7.37 per share.

$s = \$100{,}000$

$E_1 = \$132{,}000$

$$n = \frac{s}{P_0} = 13{,}572 \text{ shares}$$

$n_1 = 113{,}572$

$e_1 = E_1 \div n_1 = \$1.16$

$d_1 = D_1 \div n_1 = \$0.81$

$$P_1 = \frac{d_1}{k_e - g} = \$7.14$$

Selling stock to meet capital needs when the market price is below book drives earnings per share, dividends per share, and market price per share to lower levels.

As in case 1, the effect of investors' correctly anticipating the industry's investment of inadequate rates of return is to accentuate the effect of the simplistic examples. If anticipated, the case 2 investment would be reflected in preissue stock prices less than $7.37, necessitating the issuance of more than 13,572 shares to raise $100,000 and thereby exacerbating the investment's damage to earnings and dividends per share.

* Based on testimony by Dr. Michael L. Tennican before the New York Public Service Commission in case 176.79 proceeding on motion of the commission to investigate the financing plans for major New York combination electric and gas companies, Feb. 4, 1981.

APPENDIX 8C.–COMPARISON OF STATE ELECTRIC UTILITY REGULATING PRACTICES

State	Ranking	Rate base	Test period	Accounting	Regulatory timing
Alabama	E	Year-end original cost	Historical-adjusted	Normalization of accounting department and ITC, AFDC offset	7 months, interim relief occasionally
Arizona	c +	Year-end value, some CWIP	Historical-adjusted	Partial normalization of accounting department (TEP) normalizes ITC, (AZP) flows through ITC	No statutory limit, recent decision 7-10 months, emergency interim relief
Arkansas	C+	Year-end original cost	Historical-adjusted	Normalization of accounting department and ITC, AFDC offset, deferred fuel	*6-8* months, emergency interim relief
California	C+	Average original cost	Projected	Flowthrough of accounting department and ITC, deferred fuel	12 months, interim relief occasionally
Colorado	C+	Year-end original cost, some CWIP	Partially projected	Normalization of accounting department and ITC	*8* months, interim relief
Connecticut	C	Year-end original cost, no CWIP	Historical-adjusted	Flowthrough of accounting department and 1971 ITC Unbilled revenue and deferred fuel	5-month statutory plus l-month notice, infrequent interim relief
Delaware	C+	Average original cost Some CWIP for pollution control	Historical-adjusted	Normalization of post Jan. 1, 1975 accounting department and ITC, deferred fuel	7-month statutory recent decision 7-10 months, interim relief up to 15 percent
District of Columbia	D	Year-end original cost	Historical-adjusted	Normalization of Jan. 1975 accounting department and 6 percent ITC, deferred fuel and unbilled revenue AFDC offset	No statutory limit 9-24 months possible, emergency interim relief
Florida	B+	Average original cost, some CWIP	Projected	Normalization of accounting department and ITC, deferred fuel	8-month statutory, interim relief
Georgia	D	Year-end or average original cost	Partially projected	Normalization of accounting department and ITC, AFDC offset	6-month statutory, some emergency interim relief
Hawaii	B–	Average original cost	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	9-month statutory, no interim relief
Idaho	C	Year-end original cost, some CWIP	Historical-adjusted or partial projected	Normalization of accounting department and ITC	7-month statutory, infrequent interim relief
Illinois	C	Year-end original cost, modified for fair value, some CWIP	Partially projected or historical-adjusted	Normalization of accounting department and ITC	1 l-month statutory infrequent interim relief

State	Ranking	Rate base	Test period	Accounting	Regulatory timing
Indiana	A	Year-end fair value, 30 "/0-45 "/0 above original cost	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	6-10 months, no statutory requirement, emergency interim relief
Iowa	C–	Average original cost	Historical	Normalization of accounting department and ITC	18-24 months, interim rates are allowed 1-4 months after application
Kansas	c	Year-end original cost	Historical-adjusted	Normalization of accounting department, repair allowances and ITC	8 months, interim relief occasionally
Kentucky	B –	Year-end original cost, CWIP included	Historical-adjusted	Normalization of accounting department and ITC	10-month statutory, interim relief goes into effect 5½ months after application
Louisiana	D	Average original cost, some CWIP	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	12 months, interim relief
Maine	C –	Average original cost	Historical-adjusted	Normalization of ITC and most accounting departments	9-month statutory, emergency interim relief
Maryland	C	Average original cost, fair value by statute, some CWIP included	Historical-adjusted	Normalization of ITC and most accounting departments	7-month statutory, 3 months on make whole, no interim relief
Massachusetts	C	Year-end original cost	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	6-month statutory, limited interim relief
Michigan	C	Average original cost	Projected or partially-projected	Normalization of accounting department and ITC, AFDC offset	9-month statutory, recent orders, 12-18 months, emergency interim relief
Minnesota	C	Average original cost, some CWIP included	Projected	Normalization of accounting department and ITC, deferred fuel	12-month statutory 9-10 months, interim rates 90 days
Mississippi	D	Average original cost, fair value by statute	Projected	Normalization of accounting department and ITC, AFDC offset	6 months, interim rates go into effect 1 month after filing
Missouri	E	Year-end original cost	Historical-adjusted	Normalization of accounting department and ITC	1 l-month statutory, emergency interim relief
Montana	D	Average original cost, no CWIP	Historical-adjusted	Normalization of accounting department and ITC	9-month statutory, emergency interim relief
Nevada	c +	Year-end original cost, some CWIP	Historical-adjusted	Normalization of ITC, (SRP) normalizes accounting department (NVP) flows through accounting department, unbilled revenue	6-month statutory, no interim relief
New Hampshire	C+	Average original cost	Historical-adjusted	Normalization of ITC and most accounting departments, deferred fuel	12-month statutory, interim relief

State	Ranking	Rate base	Test period	Accounting	Regulatory timing
New Jersey	c +	Year-end original cost, some CWIP	Historical-adjusted or partially projected	Normalization of accounting department and ITC, deferred fuel	9-month statutory, emergency interim relief
New Mexico	B –	Year-end original cost, fair value by statute, some CWIP	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	4-10 months, infrequent interim relief
New York	C	Year-end or average original cost, some CWIP	Projected	ADR and post 1975 ITC normalized, balance flowed through, deferred fuel	1 l-month statutory, emergency interim relief
North Carolina	B	Year-end original cost, some CWIP included	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	7 months, infrequent interim relief
North Dakota	E	Average original cost	Historical-adjusted or projected	Normalization of accounting department and ITC	12-month statutory, decision usually 5-9 months, some interim relief
Ohio	C+	Average original cost, some CWIP	Partially projected	Normalization of accounting department and ITC	9 months, emergency interim relief
Oklahoma	C–	Year-end original cost	Historical-adjusted	Normalization of accounting department and ITC	8-12 months, emergency interim relief
Oregon	C+	Average original cost	Projected	Most tax deferrals from liberalized depreciation are flowed through, ITC normalized	10-month statutory, no interim relief
Pennsylvania	C -	Year-end original cost, pollution control CWIP only	Partially projected	Deferred fuel	9-month statutory, emergency interim relief
Rhode Island	D	Average original cost	Historical-adjusted	Normalization of accounting department and ITC	9 months, no interim rates
South Carolina	c +	Year-end original cost, some CWIP	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	10-13 months, interim rates after 30 days
South Dakota	E	—	Historical-adjusted	Normalization of ITC and most accounting departments	6 months, some interim relief
Texas	A	Year-end original cost, fair value by statute, some CWIP	Historical-adjusted	Normalization of accounting department and ITC	4-6 months, no interim relief
Utah	A–	Average original cost, some CWIP	Partially estimated	Normalization of accounting department and ITC, deferred fuel, unbilled revenue	8-month statutory, some interim relief
Vermont	C+	Average original cost, some CWIP included	Historical-adjusted	Flowthrough of accounting department, ITC normalized	6-18 months, emergency interim relief
Virginia	C	Year-end original cost, some CWIP	Historical-adjusted	Normalization of accounting department and ITC, deferred fuel	5 months statutory, emergency interim relief

State	Ranking	Rate base	Test period	Accounting	Regulatory timing
Washington	C	Average original cost, inclusion of CWIP varies	Historical-adjusted	Normalization or flow through varies depending on utility	1 l-month statutory, emergency interim relief
West Virginia	D	Average original cost, some CWIP	Historical-adjusted	Flow through or accounting department, ITC normalized	12 months plus (no limit), some interim relief
Wisconsin	B	Average original cost, some CWIP	Projected	Normalization of accounting department and ITC, deferred fuel	9-12 months, most interims granted (4-5 months after filing)
Wyoming	c +	Year-end original or historical cost	Historical-adjusted	Normalization of accounting department and ITC, AFDC offset	6-9 months, some interim relief

NOTE: On abbreviations CWIP means construction work in progress can be Included in the rate base, ITC means Investment tax credit, AFDC means allowance for funds used during construction

SOURCE: Salomon Brothers, Industry Analysis, February 17, 1981.