Chapter VI

UTILITIES AND FUEL OIL DISTRIBUTORS

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UTILITIES AND FUEL OIL DISTRIBUTORS

ELECTRIC AND GAS UTILITIES

Introduction

The electric and natural gas utility industries serve as the conduit through which American households receive most–and sometimes all —of the energy used in their residences. Sharp increases in utility bills in recent years, along with such emergencies as blackouts and brownouts, have made American homeowners and renters increasingly aware of the critical role that utility companies play.

Probably no industry — not even the petroleum industry— has experienced the profound impact on its operations and policy decisions felt by the utility industry in the wake of the energy crisis of the 1970's. Other industries have experienced increased prices and or curtailed supplies; so have the utilities. But utility companies have also come up against societal demands for change in their fundamental purposes, plans, financial management, and delivery of service.

Thus, the entire relationship between utilities and their residential customers has shifted. After years of enjoying declining or stable real prices, promoting greater energy use, and responding to rapid growth in residential energy consumption, utilities are suddenly being asked to help their residential consumers use less gas and electricity.

To understand the role of electric utilities in the consumption and conservation of energy in the home, it is useful to review briefly the structure and historical development of the industry and the regulatory environment in which it operates. Following a discussion of these items, this chapter examines utility activities as they relate to residential energy conservation. Information programs, energy audits, conservation investment assistance, rate reform, and load management are examined.

Electric Utility Industry Structure and Historical Development

The electric utility industry is a diverse group of more than 3,500 companies, both publicly and privately owned, collectively comprising one of the Nation's largest industries. Some companies engage in all three of the industry's major functions —the generation, transmission, and distribution of electric power. Most, however, serve only as local distributors of power. Publicly owned municipal and cooperative companies, in particular, tend to purchase electricity from generating companies that may be investor-owned or federally operated entities such as the Tennessee Valley Authority (TVA). The term "electric utility," as used here, refers to a distributor of electricity, regardless of whether the company generates its own power. Electric utilities may also serve as distributors of natural gas.

Although publicly and cooperatively owned electric companies outnumber private investor-owned firms by almost 10 to 1, the private companies dominate the industry in terms of generating capacity and quantity of electricity delivered. Furthermore, the largest 200 (out of a total of 400) investor-owned companies account for three-quarters of the Nation's total electric-generating capacity and serve 80 percent of all electric customers.

The electric utility industry is the Nation's most capital-intensive industry. In 1977, investor-owned electric power companies had aggregate plant investments of $190.4 billion and annual revenues of $58.8 billion, or a total investment of $3.24 for each dollar of annual sales [2] Attracting the capital needed for plant

[1] Booz, Allen & Hamilton, Inc., *Utility Role in Residential Conservation,* report to OTA, May 1978

[2] Energy Data Reports, Department of Energy, CRN 78032 3-9919, Mar. 22,1978

expansion was not difficult for the utility sector until recently, as the industry's high, steady, and seemingly predictable growth, and its regulated return, were attractive to investors seeking secure earnings.

Before the oil embargo of 1973-74, personal incomes and retail prices paid for consumer goods in the United States grew much faster than retail electricity prices, so that "real" power prices — adjusted for inflation —fell. While the Consumer Price Index rose 31 percent and real family income rose 34 percent between 1960 and 1970, the price of electricity grew by only 12 percent. By contrast, medical care cost 52 percent more in 1970 than in 1960, while the increase for food was 31 percent and for homeownership 49 percent.[3] The growth of electricity use in the United States, closely related to these economic trends, was also encouraged by the promotional activities of the electric utilities.

Low fuel costs for power generation have been one reason for traditionally low electricity prices. Another reason is that utilities have, until recently, enjoyed increases in productivity through economies of scale in generating equipment and improvements in thermal efficiency of boilers. The prospect of scale economies made the utilities' promotion of electricity beneficial to both shareholders and consumers during the pre-embargo period. As falling real prices and promotional activities encouraged growth, steady increases in consumption led to lower unit costs and, incidentally, made future planning a straightforward process of extrapolating from past trends.

As long as the electric utilities enjoyed rising productivity, they remained a declining marginal cost industry —that is, the incremental cost of electricity generated to meet new demand was lower than the average costs incurred by the power companies to meet existing demand. This situation facilitated the financing of new powerplants, the construction of which could be planned, financed, and carried out in a few years.

The result of all these advantages, in the period before the mid-1970's, was long-term security in the electric power sector. Today, by contrast, utility companies find themselves facing high costs for new capacity and for fuel; new regulatory requirements for environmental protection, nuclear safety, and energy conservation; and uncertain future growth projections and capital availability prospects.

The Regulatory Environment

For investor-owned utilities, most regulation occurs at the State level. The Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission, regulates only the interstate transmission of power and the sale of power for resale (wholesale sales). State regulation is carried out by public utility commissions whose members are either elected or, more commonly, appointed by Governors (sometime with legislative consent) to serve fixed terms. The commissions function as quasi-judicial bodies and hand down decisions on rates and powerplant sitings after public hearings. Municipally owned utilities are usually regulated by local government officials, while cooperatively owned power systems are regulated by elected boards representing the consumer-owners. Regardless of ownership, all utilities are constrained from the arbitrary use of their monopoly power by the regulators, who require them to perform certain duties (such as providing a reliable power supply to all those who pay for it) in exchange for authorizing a "fair and reasonable" rate of return.

Electric utility rate regulation involves two major steps. The first step is to approve a level of revenues adequate to cover costs for operation and maintenance, debt service, depreciation, and taxes, plus a "fair and reasonable" rate of return on invested capital. The utility commission attempts to establish a rate of return that is high enough to attract capital for future expansion, yet not so high as to overcharge consumers or violate the "fair and reasonable" standard.

[3] *Statistical Abstract of the United States* (Washington, D. C.: 1977).

The second step in utility regulation is to establish the rates at which electricity is to be sold in order to produce the allowed revenues. The ratemaking process is normally based on a "cost-of-service study," a tool used by utilities to break down their total costs over a specified time period among the different functions (generation, transmission, and distribution), customer classes (residential, commercial, and industrial), and cost classifications (customer, demand, and energy).

Cost classifications require some explanation. Customer costs include such expenses as meters, distribution lines connected to the customer's service address, billing, and marketing. As a general rule, customer costs vary hardly at all with consumption levels. Demand costs are fixed costs reflecting the company's investment in plant capacity and a portion of the transmission and distribution expenses; they represent the cost of providing the maximum (or peak) amount of power required by the system at any time. Energy costs are variable; they depend directly on the amount of power used by the system's customers. This cost category includes fuel costs, costs involved in running and maintaining the boilers, or in producing hydroelectric power (including pumped storage), and certain costs incurred in purchasing power from other generating companies.

Assigning customer costs and energy costs to different classes of customers is a fairly straightforward exercise, but allocating demand costs is more difficult. Here, a degree of judgment is required. Once the total contribution of each consuming class to the functional and classified costs is estimated, the totals are divided by the number of billing demand units in each class and translated into rates. In most cases — and in almost all situations involving residential customers — the customer, energy, and demand charges are not identified separately for the customer. Rather, they are lumped together in a single kilowatthour rate. For residential consumers, the customer charges are usually included in the rate charged for the first increments (or blocks) of power consumed each month (measured in kilowatthours), in order to ensure that they are recovered. Power companies usually charge a minimal fee even when no power at all is used, to cover these fixed customer costs. Consequently, the first blocks of power are more expensive than additional blocks consumed in the same month and the most common rate design is called a "declining block" rate. Until recently, most utility commissions have left the details of this second regulatory step, the design of rates, largely to the discretion of the utilities, with pro forma commission approval.

The Problems of Recent Changes for the Electric Utility Industry

In recent years, utilities have experienced changes — many of them traumatic — in every aspect of their operations. Like all fossil fuel consumers, utilities have faced drastic increases in the price of fuel, particularly oil. While utility fuel cost rose 24 percent between 1965 and 1970, they jumped a startling 248 percent between 1971 and 1976.[4] In the face of such rapid cost increases, regulators have permitted the electric companies to pass on higher fuel costs to their electric customers through automatic "fuel adjustment clauses," without waiting for normally lengthy ratemaking proceedings before increasing rates. These clauses have reduced hardships that utilities would otherwise have experienced by shortening the regulatory lag and eliminating the need for constant repetition of hearings and findings in response to requests for rate increases. Whether fuel adjustment clauses have also served as disincentives to energetic utility searches for inexpensive fuels or alternative energy sources is a question currently under review in many State utility commissions. They have been major contributors to continuous increases in residential electric customers' bills, making the utilities the target of resentment and suspicion. Low-income customers and persons on fixed incomes have suffered particularly from large increases in their bills. Delinquent accounts have increased, as have

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'Electric Utility Rate Design Study, Rate Design and *Load Control; Issues and Directions,* A Report to the National Association of Regulatory Utility Commissioners, November 1977, p. 10.

meter tampering and theft. In the two successive cold winters of *1976-77* and *1977-78,* there were occasional news accounts of poor people freezing to death after utility shutoffs for nonpayment of bills. Some States enacted emergency relief programs that prohibited such shutoffs, and the Federal Government offered grants and loans to help pay the bills.

Utility managers have expressed surprise at their apparent fall into disfavor with many customers as rates have risen; typically, the electric (and gas) companies see themselves as analogous to the Greek messenger who was executed for bearing bad tidings. Public opinion surveys document a widespread public belief that the utilities are profiting from the energy crisis and are highly suspect as sources of information about the crisis and its remedies. ' Many consumers appear not to understand the reasons behind their higher bills, and they attribute all rate increases to attempts to increase profits.[6]

Fuel prices accounted for approximately 60 percent of all rate increases in 1974, but they are not the only reason for rising utility bills. Plant costs have also risen sharply, According to figures compiled by the Department of Energy (DOE), a single 1,000-MW nuclear plant begun in 1967 and brought online in 1972 cost an average of approximately $150 million to build, while a similar plant begun in 1976 and expected to be ready in 1986 will have total projected costs of $1.15 billion–10 times as high. A coal-fired plant begun in 1966 and placed in service in 1972 cost $100 million, while a comparable plant constructed between 1976 and 1986 will cost $950 million—again almost a tenfold increase. ' A greatly lengthened period of planning and construction accounts for a significant portion of these higher plant costs. Caused in part by what John H. Crowley calls an "exponential increase in regulatory requirements," these delays contribute in turn to massive increases in interest paid on borrowed capital during construction. Protracted licensing procedures, inflation in labor costs, added hardware for safety and environmental protection, and higher interest rates all add to plant costs. I n 1950, the average interest rate paid by utilities on newly issued bonds was 2.8 percent; in 1970, the rate was 8.8 percent, and by 1975 it had reached 10.0 percent.[8] Utilities must now look to external sources for most of their capital needs. As a result of all these factors, the electric utility sector is now an industry of increasing marginal costs—that is, the incremental cost of producing one more demand unit is higher than the average unit cost for meeting existing demand.

Regulatory changes have also caused some discomfort for the utilities. While the electric light and power industry could hardly be considered a textbook illustration of the free enterprise system at work — marked, as it is, by governmental regulation of profits and prices, as well as by its own monopoly control of markets and the power of eminent domain – utility managers have nonetheless tended to identify with business interests and to resent the expansion of Government power. They have, consequently, found themselves in an increasingly adversary relationship with regulators at both the State and Federal levels, as utility commissions and Federal agencies have reached ever deeper into their operations.

Utility regulators have responded to newly felt public needs to conserve energy, protect the environment, and deal with new consumer activism. Some State commissions began in the earl y 1970's to disallow the costs of promotional advertising as operational expenses. Some attempted to prohibit advertising altogether. A few have required experiments in new rate designs, such as peakload (time-of-day and seasonal) pricing and "lifeline" rates to subsidize poor and elderly consumers. Many commissions, most notably the California Public Utilities Commission, have begun to take a closer look at requests for new generating capacity, to see if energy conservation programs could delay or eliminate the need for proposed additional powerplants. Some have required utilities to initiate conservation pro-

[5]Electric Utility Rate Design Study, op. cit., p. 83.

'Ibid.

'John H. Crowley, "Power Plant Cost Estimates Put to the Test," *Nuclear* Engineering International, July 1978, p. 41.

[8]Electric Utility Rate Design Study, op. cit., p. 11.

grams involving the sale, installation, or financing of insulation and other energy-conserving features for consumers. These new initiatives have come both from aggressive interpretations of existing mandates and from new State legislation.

Utilities are also being asked to meet new requirements imposed at the Federal level. Air and water quality standards mandated by Congress and enforced by the Environmental Protection Agency have accelerated the retirement of some older plants and required the installation of sophisticated control equipment on both existing and new plants. Many companies have altered their boiler fuels more than once to respond to Federal directives; after shifting from coal to oil or gas to meet air quality requirements, they have been asked by the Federal Energy Administration (and the more recent DOE) to convert back to coal to avert oil and gas shortages and cut imports. As nuclear power has begun to produce an important share of the Nation's total generating capacity, power companies have found it necessary to deal at great length and expense with the Nuclear Regulatory Commission (formerly the Atomic Energy Commission).

Gas Utility Structure and Regulatory Environment

Most gas utilities serve only as retail distributors, purchasing natural gas at wholesale rates from a relatively small number of 13 pipeline companies, which purchase in turn from producers. Among the 1,600 retail natural gas distributors, private companies predominate in terms of both their share of the industry (two-thirds of all gas companies) and the quantity of gas they sell, as a percentage of total sales (90 percent). Many of these companies are combination gas-and-electric companies; these account for 40 percent of all natural gas sales.[9]

Almost two-thirds of the natural gas sold by utilities comes from the interstate market, where its price is regulated by FERC. Intrastate gas prices have been regulated by the public utility commissions of States in which the gas is produced and consumed. With passage of the Natural Gas Policy Act of 1978, intrastate prices have been slated to come under Federal regulation.

The separate regulatory systems for intrastate and interstate gas have contributed, over the years, to imbalances in both price and supply. Intrastate gas, which is not regulated at the wellhead, has generally been priced closer to competitive or substitute fuels such as distillate fuel oil. Interstate wellhead prices, on the other hand, which are subject to cost-based Federal regulation, have been lower priced than substitute fuels. As a consequence, producers have kept as much gas as possible within the producing States which has helped bring about an imbalance in supply between the two systems. Even though wellhead prices are generally higher in producing States, the prices residential consumers pay is lower with some exceptions. This discrepancy in part is due to higher transmission costs for those living far from the producing regions and the need to supplement the flowing gas supply in the nonproducing regions in times of shortage.

The intrastate/interstate price discrepancies have increased during the last few years, as gas-short utilities in the nonproducing States have had to turn to high-priced supplemental gas sources such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) and propane just to meet their existing customers' needs. Expansion of their markets has been precluded in many areas by the supply shortages. Industrial customers in some consuming States have wearied of constant interruptions in their gas service and have permanently turned in large numbers to other fuels, particularly distillate fuel oil. Ironically, industrial fuel shifts have freed up enough gas in some places to cause pocket surpluses. But where utilities were prohibited from providing service to new customers, they had no market for this surplus gas and had to relinquish it to other distributors.

Historically, the gas utility industry has relied primarily on long-term debt to finance its capital needs. Its capital intensity has declined over the last 25 years, going from

[9]Booz, Allen & Hamilton, op. cit.

$3.00 in total investment per $1.00 of sales revenues in 1950 to $1.75 in total investment per $1.00 of sales in 1975. '0

Recent Changes in the Gas Utility Industry

Like the electric utilities, gas companies have experienced a number of traumatic changes in recent years. In many regions, utilities have been totally unable to take on new customers and have had to curtail not only their large industrial customers whose contracts anticipated interruptions in service at times of peak demand, but also some customers whose contracts and rates were based on more expensive "firm" service. Allocations of scarce gas supplies by Federal and State agencies have caused some utilities to lose gas to other companies. While the need to conserve gas has been obvious from a national policy standpoint, the most immediate and direct benefits of such conservation have not always been available to the companies that were able to save supplies, only to see them allocated to others.

Recent passage of the National Gas Policy Act has brought a prospect of major changes for gas utilities and their customers. The new law paved the way for gradual deregulation of most gas prices and brought intrastate gas under Federal regulation for the first time, reducing the price gap between interstate and intrastate gas. High-cost gas is to be deregulated first, and the regulated price of other gas will be allowed to rise gradually from legislatively mandated ceiling prices, using annual inflation rates as guides for increases. Deregulation will be virtually complete by 1985.

Utilities will pay much higher prices for gas under the new legislation. Interstate pipeline companies will pass on to utilities the higher prices paid by pipelines for gas supplies, and the utilities will pass on the increases in turn to their own customers. Residential gas utility customers will be sheltered initially, however, from the increase in natural gas prices because of a provision for "incremental pricing" under which large industrial customers using gas as a boiler fuel will bear the full additional price burden –to a point. When incremental pricing causes industrial gas rates to exceed the cost of alternative fuels, the burden of higher gas prices in excess of alternative fuel costs will be shared by al I gas consumers.

Just how soon residential gas users feel the impact of the new legislation on their monthly utility bills is a matter of considerable debate. The number of industrial customers subject to the incremental pricing provisions is limited somewhat by the new law; only interstate customers, and only those who use gas as a boiler fuel (as opposed to a process feedstock), are affected. If rising industrial gas prices or requirements of the coal conversion legislation cause many industries to shift to alternative fuels (including, perhaps, imported fuel oil), then the fixed costs associated with gas pipeline transmission and storage must be shared by the remaining customers. The smaller the group of industrial customers subject to incremental pricing, the sooner the peak price— on a par with alternative fuels — is reached and the high-cost burden becomes dispersed among residential and commercial customers as well as industries.

As residential natural gas prices continue to rise steeply —and the Energy Information Administration estimates that they could reach $3.31 per mcf in 1976 dollars by 1985–homeowners will have an even stronger incentive to conserve and overall consumption growth in the residential sector will continue to decline. On the other hand, the higher prices could cause special hardships for the poor and the elderly. Even without direct increases in gas prices, families will bear indirect costs through higher prices for products of industrial gas users subject to incremental pricing.

Also uncertain is the effect the new legislation will have on gas supplies for utilities and residential users. Experts in the producing industry believe that the new higher prices will stimulate exploration and production in fields previously inaccessible for economic reasons, and that ample supplies will tend to hold down prices to some extent. Consumer advocates, on

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the other hand, dispute the claim that deregulation will stimulate growth in production before 1985 and that a competitive market is at work which will restrain price increases.

Utilities and Residential Consumers

The 74 million U.S. households accounted for one-third of the electric utility industry's sales of 1.85 trillion kWh of electricity in 1976, and for just under 40 percent of the utility revenues of $53.5 billion. The average American family consumed 8,400 kWh of electricity in *1976,* spending $288, or 3.45 cents per kWh (as compared with 2.89 cents per kWh for customers who heat electrically). Virtually all homes in the United States are served by electricity, with 12.6 percent of all occupied housing units heated electrically in 1976.2

Forty-one million households with natural gas service accounted for one-third of the gas utility industry's sales of 14.8 quadrillion Btu (Quads) in *1976,* bringing in revenues of $9.9 billion, or 41.9 percent of the industry's total revenues of $23.6 billion. Gas was the heating fuel for 56.4 percent of all occupied housing units in 1976.3

Utility bills, like taxes, are a continuing source of particular unhappiness to consumers. I n fact, however, utility price statistics reveal just how great a bargain electric and gas consumers have enjoyed, at least until recently. Using constant 1976 dollars, which take account of inflation, table 55 indicates that real utility prices fell steadily during the 1960's. Although that trend has since been reversed, real gas prices in 1977 were still only 12.2 percent higher than their *1960* levels, while real electricity prices were still 17.7 percent lower in 1977 than in 1960. Table 56 shows the percentage change over certain indicated periods.

Table 55.–Residential Natural Gas and Electric Prices (1976 dollars, selected years, 1960-77)

Year	Natural gas ($/mcf)		Electricity (¢/kWh)	
	1976 dollars	Current dollars	1976 dollars	Current dollars
1960	1.97	1.03	$.043	$.024
1965	1.76	1.05	.035	.022
1970	1.58	1.90	.028	.021
1971	1.58	1.15	.028	.021
1972	1.64	1.21	.031	.022
1973	1.64	1.29	.031	.023
1974	1.69	1.43	.031	.028
1975	1.77	1.70	.032	.032
1976	1.98	1.98	.034	.034
1977	2.21	2.34	.035	.037

SOURCE: Adapted from Demand and Conservation Panel of the Committee on Nuclear and Alternative Energy Systems, "U.S. Energy Demand: Some Low Energy Futures," *Science,* Apr. 14, 1978, pp. 142-153.

Table 56.—Percentage Changes in Real Utility Prices, Selected Periods, 1960-77

Period	Natural gas	Electricity
1960-65	– 10.7	-17.6
1965-70	– 10.2	– 21.1
1970-75	+ 12.0	+ 14.3
1975-77	+ 24.8	+ 10.6

SOURCE: Adapted from Science, Apr. 14,1978, pp. 142-152.

Consumer ire can best be accounted for by the suddenness of the increases and the degree to which they have contradicted long-term historical experience. For consumer activists who follow utility rate increase proceedings, the aggregate amounts requested in recent years also boggle the mind. Total annual rate increases granted to electric utilities across the country between *1961* and 1968 came to *$16* million. From 1969 to 1976 the annual total was $1.4 billion, almost a tenfold increase. "

[1] *Factbook on the Proposed Natural Gas Bill,* prepared by the Citizen Labor Energy Coalition, Energy Action, and the Energy Policy Task Force, Sept. 25, 1978, p. 21, supra.

[12] *Statistical Abstract of the United States, 1977.*

[13] Ibid.

"Electric Utility Rate Design Study, op. cit., p, 13.

The high prices consumers are paying (and to a lesser extent, the perceived threat of shortages) have created a new interest in the possibilities of conservation. Investment in insulation, weatherstripping and caulking, thermostats with automatic nighttime setbacks, and furnace efficiency improvements have all begun to look attractive to homeowners.

Many utility companies have tried to help their residential customers to conserve by initiating a variety of conservation programs, ranging from simple "bill-stuffers" providing information on how to conserve to extensive programs of insulation financing and installation, rate reform, and load management. The balance of this section describes these programs and analyzes the policy issues they raise for utilities and their consumers.

Utility Activities in Residential Energy Conservation

Information Programs

The simplest (and often the first) conservation activity undertaken by utility companies is to promote conservation by providing, in flyers sent to customers with their monthly bills, "how-to" information and reasons for cutting down on waste. These efforts, now common among gas and electric companies throughout the Nation, are natural substitutes for the "bill-stuffers" of earlier years. Only the products have changed: while the brochures of the 1950's and 1960's urged homeowners to invest in electric heating and air-conditioning, frost-free refrigerators, and other energy-consuming commodities, the current promotional literature extolls the merits of insulation and weatherstripping, along with practices such as lowering thermostats and cooking one-dish meals. This kind of information dissemination costs the utility little and can be useful to consumers. Attitudinal surveys provide evidence, however, that consumers generally regard utilities as suspect sources of information.[15] Unfortunately, there are no easy ways to measure the cause-and-effect relationship between these information programs and consumers' actions in undertaking conservation measures.

More concrete information is provided to residential consumers by utilities that provide "energy audits" of individual homes. Making use of specially trained staff members and computer programs, utility audits include a survey of the home to determine the current level of insulation, the presence or absence of storm windows, and other structural details. The audits also include information about the historical energy consumption and costs associated with energy use in the home. They generally conclude with information about the cost of upgrading the thermal integrity of the structure through investments in insulation and other features, estimates of the energy and money that could be saved, and the amount of time needed to amortize the conservation investment through savings on utility bills.

Many utility companies conduct audits for all requesting homeowners in their service areas regardless of the fuel used for heating the home. Gas and electric companies, for example, audit homes that are heated by oil. In such cases they must rely on estimates or on customers' records (often incomplete) for historical heating cost data, and, inaccuracies in projected savings may be a problem. Even when relying on complete past billing records, auditors may either overestimate or underestimate both the potential savings and the lifecycle costs of insulation investments. Utility managers are concerned about the credibility and liability problems they may incur if customers are dissatisfied after relying on utility-conducted audits for promises of savings of energy or dollars that do not materialize. Despite the imperfections inherent in home energy audits, they are valuable tools for homeowners seeking practical guidance in improving the energy efficiency of their dwellings

Other conservation information programs carried out by utilities may include guidance for builders about energy-efficient construction and efficient appliances and heating systems. The Tennessee Valley Authority, for example, offers free seminars on heat pump design and installation for builders and contrac-

[15] Ibid., p. 83.

tors. Some companies offer special awards to builders who construct energy-conserving houses. Seattle's Washington Natural Gas Company contacts all builders who obtain local building permits, urging them to use energy-efficient structural materials and heating, ventilating, and air-conditioning (HVAC) systems, A few utilities have constructed demonstration homes to display the latest in energy-conserving construction and systems and to improve their own conservation information through research and monitoring.

Conservation Investment Assistance Programs

A more direct involvement in conservation can be seen with utilities that offer customers installation and financing services for insulating their homes. Typically, loans offered by the utilities may be repaid through regular monthly bills. Michigan Consolidated Gas Company, an early entrant into the insulation business, offers its customers up to $700 in loans to purchase ceiling insulation, with no downpayment requirement, at 12-percent annual interest, with 3 years to pay. Actual installation is done either by utility-approved contractors or by the homeowners themselves. The company estimates that approximately 140,000 homes within its service area have been insulated since its program began, but only 800 customers have taken advantage of the financing opportunity. Michigan Consolidated considers its insulation program a public service and the State's public service commission concurs; as such, its administrative costs are included among the company's allowable operating expenses. This means that all customers, whether or not they participate in the insulation program, share these costs in their utility bills. Some experts believe this situation constitutes unjust discrimination in ratesetting, while others find it justifiable since all customers presumably benefit from the utility's increased supply of gas acquired through conservation. One proponent of the Michigan Consolidated approach, the former chairman of the Michigan Public Service Commission, points to the similarity between the practice of including conservation program costs in the utility's revenue requirement and the now-defunct policy– upheld in the courts—of subsidizing hookups for new customers in order to benefit all customers through economies of scale.[16]

Washington Natural Gas Company has taken a different approach in its ambitious energy conservation program. It offers not only ceiling insulation, but also sidewall insulation, night setback thermostats, storm windows, furnace ignition devices (to eliminate pilot lights), and new furnaces and water heaters that meet certain efficiency standards. Because of the large total expense incurred by customers who buy several of these items, 45 percent of Washington Natural Gas's conservation customers take advantage of the company's financing arrangements. Even this number is lower than the company expected at the outset; it suggests a greater-than-anticipated consumer ability to pay for energy improvements. The utility's conservation business is carried out as a merchandising operation, which recoups its own costs and earns a modest profit. Hence, the gas company's normal operations and rates are not affected by its conservation activities. The company uses independent contractors to install the conservation devices, and the utility's management believes its program has benefited these small businessmen by stimulating a substantial volume of business.[7]

A number of policy issues emerge from this new area of utility activity. The companies themselves have expressed concern about possibly adverse legal, financial, and management effects of conservation investment assistance programs, particularly if company participation were to be made mandatory by State or Federal legislation. Insulation manufacturers have worried about potential supply problems and consequent "demand pull" inflation stemming from utility-produced demand for their products. (See appendix A for a discussion of the insulation supply problem.) And some consumer advocates fear that utilities will use

"William G. Rosenberg, "Conservation Investments by Gas Utilities as a Gas Supply Option," *Public Utilities Fortnight/y,* Jan. 20,1977, p.19.

[1] 'Information provided to OTA by Don Navarre, Vice President for Marketing, Washington Natural Gas Company

their conservation programs to realize windfall profits, extend their monopoly powers into a currently competitive market, justify unfair or unnecessary rate increases, or otherwise work in ways contrary to the public interest.

Little empirical information is available to substantiate or refute these concerns. The debate about utilities' roles in residential energy conservation is primarily theoretical. It is useful, however, to review the major points of concern and outline the limited available information about the corporate, societal, and consumer impacts of utility conservation assistance programs.

In recommending the installation of supplemental insulation and other conservation devices, utilities are often asked to estimate the amount of energy and money that could be saved by the proposed conservation investments. Utility spokesmen fear they will be held legally liable if customers later fail to achieve the promised savings. A discrepancy between projected and actual savings is not unlikely in some cases, given the difficulty of accounting for individual families' energy-consuming habits and keeping pace with the moving target of rising electric and gas rates. In fact, however, there is no record of any liability suits being filed or of judgments being made against utilities for failing to deliver promised savings, and the likelihood of such suits seems low. Utilities should be able to protect themselves through careful explanation of their methods of estimating savings and of the residual uncertainty that invariably remains.

A more serious liability threat may lie in the "implied warranty" offered by utilities who sell, finance, or even simply recommend specific insulation products or contractors. Managers have expressed concern about the quality control that customers may expect them to exercise over the efficacy and safety of insulation materials and the integrity of manufacturers and installation contractors. This matter has arisen with at least one utility's active conservation program. Some insulation dealers used by the utility as installation contractors were found to be engaging in fraudulent activities, "puffing up" blown-in insulation to make it appear more substantial in volume (and, hence, in insulating value), and installing insulation that was a dangerous fire hazard. The problem appears especially acute in the cellulose insulation industry, which is characterized by large numbers of small manufacturers and installers who are outside any recognized regulatory authority. Cellulose insulation is normally mixed on the job site, making quality control virtually impossible. Recent recognition of the need for standards of quality and performance has produced voluntary certification programs developed by the insulation industry (and in a few cases by utilities or State government agencies) in some areas. Yet the impossibility of guaranteeing absolute quality control is likely to necessitate utility actions such as disclaimers and liability insurance to protect themselves from responsibility for contractors' fraud or safety failures.

Logically, if many of an electric utility's customers decide to take advantage of the company's conservation investment assistance program (hereafter referred to simply as an "insulation program"), they will use less electricity individually and reduce the utility rate of load growth collectively. A vigorous insulation program may reduce the utility's peakload temporarily, but the long-term effect will most likely be a reduction in the growth rate, not an absolute demand drop.

An important question remains: Will the utility's total costs be reduced by this change in demand patterns, allowing the savings to be passed on to consumers in the form of lower bills–or at least slower growing bills? The answer appears to depend on a number of factors, which vary from utility to utility. A consulting group commissioned by OTA to survey utilities' experiences with and attitudes toward insulation programs found this area of uncertainty to be a matter of major concern among the companies surveyed.[19]

In planning for future capacity and capital needs, as well as for revenue and rate re-

[18] Ken Bossong, "The Case Against Private Utility Involvement in Solar/Insulation Program s," *Solar Age,* January 1978, pp. 23-27.

[19] Booz, Allen & Hamilton, op. cit.

quirements, utilities must consider the variations they typically experience between average and peakloads. If insulation programs temporarily reduce their average (or base) loads, revenues will be reduced accordingly. However, if peakloads are not reduced as well, capacity requirements will remain as great as they would be without the insulation program. In such a case, the utility must still operate expensive peaking plants during peak periods–and with lower revenues, they must raise rates to meet the fixed costs. Such an occurrence could wipe out consumer savings.

A technical note at the end of this chapter contains a detailed discussion of this perceived problem and of an OTA computer simulation that tests the likelihood of insulation programs having an adverse effect on utility load factors and costs. Using a model developed for the recent OTA study, *Application of Solar Energy to Today's Energy Needs,* OTA had simulated the total loads of hypothetical utilities in four cities that represent a cross-section of climatic variations throughout the United States. The utilities were designed to be typical in their heating and cooling loads, with a mix of single-family homes, townhouses, low- and high-rise apartments, shopping centers, industry, and streetlighting. The model tested the effect of altering the insulation levels and heating and cooling equipment for certain fractions of each utility's *1985* residential load. The results suggest that insulation programs have only a small effect on a system's load factor–that is, on the ratio of its baseload to its peakload—and by extension, on total system costs. The effect is, in most cases, positive (a higher load factor). The impact of insulation in each case depends on such things as the utility's air-conditioning load, service area climate, and electric-heating load. Table 62 in the technical note illustrates the findings, which still need to be verified through actual experience. If they prove to be correct, they should reduce the fear that insulation programs will lead to higher costs and higher rates.

The long-term picture is clearer. By slowing demand growth, insulation programs should delay new capacity needs. As new powerplants are far more expensive than old ones, this, delay should also retard rate increases.

Another corporate concern about utility insulation programs is peculiar to the gas companies. This problem centers on whether the gas utilities will be permitted to add new customers to provide a market for any gas the company saves through existing customers' conservation efforts. As residential customers save natural gas through improved insulation and other conservation measures, they free up gas supplies for possible use by an expanded number of customers. Until recently, however, many gas companies were prohibited from adding new customers, and during periods of especially short supply companies often lost a portion of their available supplies to other companies through mandatory allocation programs. Without a promise of being able to keep and sell "conservation gas" at attractive prices — a so-called "finder-keepers" policy— gas companies correctly perceive their customers' gas-saving efforts as not necessarily beneficial to their operations. Indeed, conservation in the absence of a "finders-keepers" policy means the companies will have to spread fixed-distribution costs over reduced sales.

Although a large number of utilities have initiated insulation programs either voluntarily or in response to State requirements, the major trade associations representing both publicly and privately owned utilities have gone on record to oppose detailed uniform national directives for such programs. They fear that such requirements, which were included in different forms in the House and Senate versions of the National Energy Act before being modified substantially by the Conference Committee, fail to recognize each company's unique needs arid circumstances.

Some utilities are also reluctant to undertake the new roles of moneylenders and sellers of hardware, although in fact neither activity is totally new to the industry. (In former days, many utilities sold appliances to their customers and permitted them to make installment payments on their utility bills.) The electric and gas companies' strange bedfellows, in this viewpoint, are the consumer activists.

Consumer groups are particularly fearful that small businessmen in the conservation-device and insulation businesses would suffer from unfair competition at the hands of the utilities.[20] The Washington Natural Gas experience suggests, however, that the opposite effect could also result. WNG made extensive use of small businessmen to install conservation materials.

Rate Reform for Electric Utilities

The area of electric utility rate design may eventually represent the most significant departure from past practices brought about by the changed circumstances of recent years. Declining-block rates, the rate structure usually applied to residential users, came into widespread use during the early days of electrification when lighting comprised most of the utilities' loads. Since the utilities had to maintain adequate capacity to meet a sharp peak in demand during evening hours, it made sense to promote other uses of power to fill the "valleys" of demand. Customers and utilities alike benefited from the economies of scale, and the load leveling that came with growth that was encouraged through declining-block rates. Now, however— as new capacity costs and fuel costs exceed average system costs, and as growth exacerbates peaking problems—promotional rates cease to be beneficial.

A number of State utility commissions have begun requiring utilities to experiment with departures from their traditional declining-block rate structures, using "peakload pricing," or "time-of-use rates" that rise at times of peak seasonal and/or daily demand, to encourage users to change their habits and reduce peak loads.

The area of innovative rate design — and particularly time-differentiated rate structure— is complex and controversial. This report can only touch briefly on the subject, yet its significance for residential electricity use is great enough to warrant a limited discussion of the issues surrounding peakload pricing.

[20] Bossong, op. cit

The basic argument for peakload pricing is clear: A utility's costs vary with the season and the time of day, due to the equipment and fuel mix that must be used to meet different levels of demand. These cost variations have increased in recent years, with the result that the highest operating costs are now incurred when reserve plants are pressed temporarily into service to provide peak power levels. Although these peaking plants require lower capital cost than baseload plants, they employ expensive fuels such as petroleum distillates, and they operate less efficiently than baseload plants. As a result, peak power costs run as much as four times higher than base power costs, therefore, the premise that rates should be related to costs in order to achieve objectives of equity and efficiency leads to the conclusion that rates should vary with time.

Each utility's peakload pricing system must be "custom made" to reflect the company's load characteristics, peak patterns, weather conditions, and generational equipment. The time-differentiated rate design recently offered by the Virginia Electric Power Company (VEPCO) to its residential customers is fairly typical: 2,000 VEPCO customers, chosen from among 17,000 who volunteered for the program, have had special meters (which cost the company $250 apiece) installed at their homes to record their total kilowatthour usage and their consumption during peak hours (9:00 a.m. to 9:00 p.m. e.s.t., or 10:00 a.m. to 10:00 p.m. e.d.t., Monday through Friday). The meters also measure each customer's peak demand during any 30-minute onpeak period of the billing period; the demand figure, in kilowatts, is not calculated during off peak hours. The customer's monthly bill is broken down into three separate parts:

1, A basic customer charge of $11.50 per billing month;
2. A kilowatt demand charge for onpeak demand, calculated at the following rates:
   –$.031 per kW of onpeak demand during billing months of June through September;
   –$.022 per kW of onpeak demand during billing months of October through May;

3. An energy charge calculated on the basis of the following rates:

–$.023 per kWh of on peak use.
–$.01 5 per kWh of off peak use.

The kilowatthour charges may be adjusted for changes in fuel costs (i.e., fuel adjustment clause).

Because VEPCO's time-of-use experiment has only recently begun, the company does not yet have data on the effects of the experimental rates on participants' electricity consumption or bills, or on the VEPCO system's peaks, costs, or revenues. The Virginia utility is also experimenting with time-of-use rates that are applicable to water heaters only, and with voluntary time-differentiated rates for churches and other charitable organizations whose electricity demand tends to be greatest during evenings and weekends. VEPCO has also identified 9,000 residential customers with histories of substantial summer electricity consumption (at least 3,500 kWh during at least one summer month of 1976 or 1977); these customers have been required to participate in a metering experiment in which they are not actually charged according to time-of-day rates, but are given monthly statements comparing their electricity bills under traditional pricing (which they actually pay) with costs under peak load pricing.

Because peakload pricing of electricity reflects the higher costs associated with generating and distributing power during the periods of highest demand on a utility system, such rate structures provide customers with "fair" and "appropriate" price signals. The actual level of demand elasticity—that is, customer response (through behavior changes) to price differences — is not well-understood at this time, but federally funded rate experiments are beginning to produce empirical data. (These experiments are discussed below.) The reasons for shifting to such innovative rates go beyond a desire of economists to perfect the workings of the marketplace. From the standpoint of national policy, such rates are desirable if they result in an energy savings, particularly of scarce and expensive fuels such as oil and gas.

Electricity savings at the point of end-use may or may not occur as a result of time-differentiated rates; however, energy savings at the "input" end of the utility could be substantial. This is because most utilities use their newest, most efficient and economical powerplants to generate their baseloads. Although these recently built plants typically represent large capital investments (and hence, high fixed costs) for the companies, their efficient thermal performance makes them the least expensive to run because they require fewer Btu of energy input per kilowatthour of output than do the usually older, smaller, less efficient peaking plants. Furthermore, baseload plants are more likely to use nuclear energy or coal, while peaking plants generally rely on imported oil or scarce natural gas.

To the extent that shifts in demand caused by peakload pricing can minimize use of the peaking plants and increase the proportional use of the efficient baseload plants, a net savings of energy and of operational costs should result. Over the long run, leveling peak demand could also save on fixed costs by reducing the need for construction of new plants. All these savings —of scarce fuel input, of fixed and operating costs, and perhaps of end-use electricity — represent conservation in the broad sense of the word.

Lifeline Rates

If the trend toward time-differentiated rates reflects a growing belief in the appropriateness of cost-based rates, a countervailing belief has affected some utility rates differently. "Light and heat are basic human rights and must be made available to all people at low cost for basic minimum quantities," says section 1 of the California Energy Lifeline Act of *1975.* Based on this premise, the Act required California utilities to set rates below cost for certain minimum quantities of gas and electricity—the estimated amount needed by an average family of four living in a well-insulated 1,000 ft^2 single-family house to provide enough lighting, cooking, refrigeration, water, and space heating to maintain health and a reasonable level of comfort.

So-called lifeline rates, which have also been implemented in Ohio, Georgia, and Colorado but were rejected on a national scale during the congressional debate over the Public Utilities Regulatory Policy Act of 1978, have two essential goals. First, they are intended to provide financial relief and avoid hardship for low-income families who consume only the minimum essential amount of energy in their homes. Second, they are intended to promote conservation by reversing the traditional declining-block rate structure and charging progressively higher rates for greater quantities of gas and electricity consumed. The California experience to date in striving to achieve the first purpose is discussed in chapter IV, "Low-Income Consumers." With regard to the second objective, that of promoting conservation, the California experience is not encouraging. The Pacific Gas and Electric Company found virtually no change in the average residential use of electricity during the first 2 years of the lifeline rate policy and determined that there was "little conclusive evidence as to the link between lifeline and conservation . . . customers respond more to their total bill than to any marginal price for the block in excess of lifeline (allowances)."[21]

Load Management

Load management is the deliberate manipulation of electricity demand at the point of end use, in order to maximize cost savings for the consumer, the utility system, or both. When a customer alters his energy-consuming habits to take advantage of time-differentiated rates, that customer is practicing a simple form of load management. His actions might include deferring dishwashing, clothes washing, and drying to off peak hours. On a slightly more sophisticated level, the homeowner might install a timer on the water heater to limit its operation to off peak hours. Forms of load management that are under the consumer's (rather than the utility's) control are called indirect load management.

The term "direct load management" refers to actions under the direct control of the utility company. With the consumer's prior consent, the utility installs electromechanical means by which it can manipulate a certain portion of the customer's load. When the system approaches peak levels, preceded signals transmitted over high-voltage wires or radio waves can be used to disconnect certain appliances such as hot water heaters, air-conditioner compressors, and heat pumps. Customers are sometimes given compensation for any inconvenience caused by load management, in the form of credits against their utility bills. By carefully designing the patterns in which these appliances are cycled on and off throughout the utility system, the electric company can shave the sharp spikes in demand that require the expensive operation of peaking plants. In certain cases, it may also be possible to use load management as a means of deferring or eliminating the addition of new capacity; this prospect however, is considerably less certain than the probability of saving fuel costs associated with short-term operations.

Load management has been practiced widely in Europe for many years. There, mechanical cycling or timing devices have been combined with time-differentiated rates and energy storage systems to expand the use of load management practices to heating. At least one U.S. utility, the Central Vermont Public Service (CVPS) Company, has also experimented with a heat storage/load management combination. Twenty-five of CVPS's customers have installed electric heating systems that heat water during off peak hours (11 p.m. to 7 a.m.), cease heating during onpeak hours, and keep the customers' houses warm during the daytime by circulating the preheated water throughout the house. The company calculates that in 1974-75 each customer paid approximately the same amount for this system as he would have expended for oil heat, but that a customer who would have spent $724 per year for electric resistance heat paid only $348 under the heat storage option. For the utility, the important

[21] "Lifeline Electric Rates in California: One Utility's Experience," presented by William M. Gallavan, vice president, rates and valuation, Pacific Gas and Electric Company, to the ninth annual Conference of the Institute of Public Utilities, Graduate School of Business Administration, Michigan State University, Dec. 14,1977, p. 9.

result of the experiment was the finding that each customer reduced his onpeak demand an average of 22 kW, or a total of 565 kW for the system as a whole.[22]

One danger associated with the combination of load management and time-of-day rates is the possibility that their appeal to consumers will be so successful that they will simply "chase the peaks around the clock," as a Wisconsin utility regulator put it. In Germany, preferential rates induced such a large-scale shift to storage heating systems that higher nighttime peaks occurred and the rates had to be altered, thereby reducing the economic benefits enjoyed by consumers.[23]

Direct load management, keyed to mechanisms such as temperature readings, is being tried by a number of utilities. Compared with peakload pricing, direct load management has the advantage of assured response; the utility knows for certain that it can reduce a peakload by a specific amount through mechanical means, rather than hoping for an estimated price elasticity.

Residential consumers account for an estimated average of 30 percent of U.S. utility peakloads.[24] Detroit Edison estimated that residential cooling accounts for 50 percent of summer temperature-sensitive load, the fraction of total system load that is most volatile.[25] Only a fraction of this load can be eliminated through management. A typical arrangement shuts off air-conditioner compressors and outside fans for 10 to 15 minutes for each hour, in two periods, while leaving inside fans running to circulate air throughout the participating houses. The cycling signal is activated, typically, when outside temperatures are high enough to generate a substantial systemwide demand for air-conditioning. By shutting down air-conditioners in 50 homes for 15 minutes per hour between 2 and 5 p.m. on days when temperatures exceeded 750 F, Detroit Edison was able to achieve a 25-percent reduction in these customers' air-conditioning demand. The utility's systemwide savings achieved through management of both air-conditioning and water heating were limited, however, by the fact that its summer peaks tend to be broad —that is, a high demand level is sustained for many hours during the day. While savings through water heater control amounted to 200 MW in the winter, they were only 50 to 60 MW in the summer.

A 1977 study by the Federal Energy Administration (FEA) indicated that a simulated coal-burning utility's load management program could achieve a substantial shift from peaking plants to baseload plants, and could result in significant fuel cost savings. Furthermore, when adequacy of reserve margin is the criterion for planning new capacity additions, the hypothetical utility could justify the delay of some construction plans. FEA cautioned, however, that such delays probably could not be achieved in real-life situations because of the ever-growing problems of rising costs, financing problems, and delays in licensing and construction.[26]

Load management represents a significant departure from utilities' historical obligations to provide electrical service in any quantity customers desire and are willing to pay for. It represents a form of rationing, a practice that economists argue is unnecessary when a free marketplace employing cost-based prices allocates resources. Increasingly, however, utilities and their regulators are coming to view load management as one more tool in the diverse collection of policies that can aid in encouraging utility-based residential energy conservation.

Federal Programs and Opportunities in Utility-Based Issues

Because responsibility for utility regulation rests, for the most part, with States, Federal op-

[22] "Storage Heat Shifts Load on Time at Central Vermont," *Electric Light and* Power, Mar. 15,1976, p. 3.

[23] Gordon C. Hurlbert, *Improved Load Management—New Emphasis,* Sept. 24,1975.

[24] "Survey Scrutinizes Load Management," *Electrical World,* July 15,1976.

[25] "Cooling-Demand Controls Look Good," *Electrical World,* July 15,1976.

[26] Federal Energy Administration, *The Impact of Load Management Strategies Upon Electric* Utility *Costs and Fuel Consumption,* June 1977.

portunities to encourage utility actions to stimulate residential energy conservation are limited. However, recent Federal legislation and programs do provide a framework of sorts for such utility activities.

New Legislation on Conservation Investment Assistance

The National Energy Policy Act of 1978, although not as ambitious as President Carter's original proposal to Congress, does require utilities to establish conservation programs for residential buildings of four units or less. Under the new law, utilities must inform their customers of suggested conservation measures and of available means of purchasing and financing investments in such measures. Utilities must offer onsite audits and services to assist homeowners in finding installation contractors and lenders. If the customer chooses, a utility must permit repayment for conservation investments on the regular monthly utility bill. Gas and electric companies may themselves lend customers up to $300 each for conservation investments, but they are prohibited from direct involvement in the installation of conservation measures other than furnace efficiency modifications, clock thermostats, and load management devices. Utilities already engaged in installation of other conservation measures as of the date of enactment are exempt from this prohibition.

Utilities are also prohibited, under the new law, from incorporating the administrative costs of their residential conservation programs in their rates. Instead, they must charge those customers who use their conservation services.

New Legislation on Utility Ratemaking and Load Management

The Public Utilities Regulatory Policies Act, (P. L. 95-617), passed in October 1978 as part of the overall energy legislative package, increases the level of Federal involvement in electric utility ratemaking activities. The new law does not preempt State authority, but it requires State utility regulators to consider the adoption of certain federally proposed standards in their rate determinations, and either to adopt such standards or to state in writing the reasons for not doing so. The Federal standards applicable to residential buildings are:

1. rates that reflect the cost of service to various classes of electric consumers, to the maximum extent practicable;
2. prohibition of declining-block rates for the energy component of electric rates, except where such rates can be demonstrated to reflect costs that decline as consumption increases for a given customer class;
3. time-of-day rates reflecting costs of serving each customer class at different times of the day, except where such rates are not cost-effective with respect to a customer class;
4. seasonally variable rates, to the extent that costs vary seasonally for each customer class; and
5. load management techniques offered to consumers when they are determined by a utility to be practicable, cost-effective, reliable, and advantageous to the utility in terms of energy or capacity management.

A second set of standards under the Act deals with master metering of multifamily buildings, automatic adjustment clauses, information to be provided to consumers about rates applicable to them, procedures for termination of electric service, and limitations on the inclusion in rates of costs attributable to utility promotional and political advertising.

The new law's most significant opportunity for Federal participation in utility ratemaking may well be its provision for intervention in administrative proceedings. The Secretary of Energy (along with affected utilities and consumers) is allowed to "intervene and participate as a matter of right in any ratemaking proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority." (16 U.S.C. §2601) According to the report of the conference committee on the legislation, such intervention is for the purpose of participating in the consideration of the Federal standards "or other concepts which contribute to the achievement of the purposes of the title. " The report also states a congressional intent that the phrase dealing with "other concepts" be construed broadly "so that no one will have to prove his case in advance before being allowed to intervene. " In effect, this provision for Federal intervention affords DOE a means of monitoring and encouraging effective state implementation of the Act through direct involvement in State regulatory proceedings.

DOE Electric Utility Rate Demonstration Program

Because empirical data on consumer response to alternative rate structures are scarce, the Federal Government's most helpful role may be in providing such data.

The electric utility rate demonstration program, initiated by FEA in *1975* and continued to the present by DOE seeks to analyze the results of 16 experiments with innovative rates undertaken by utilities across the country.

The rate demonstration program, on which $9.2 million in Federal funds (supplemented by at least 10-percent State and local funding) were expended through FY 1978, has focused primarily on time-of-use rates applied to residential customers. Approximately 18,000 households have been studied, either as testing units or as control points. DOE, along with cooperating State utility commissions, utilities, and consulting analysts, has been watching customers' total electricity consumption, kilowatt demand peaks, and temporal use patterns to determine the degree of price elasticity among residential users over a period of *2* to *3* years. Although the analytical phase of the rate demonstration program is still underway, some results have become available and preliminary conclusions have been drafted by DOE.

Tables 57 and 58 list the projects in DOE's rate analyses and describe the innovations tried in each test. On the basis of complete test data from two States and partial data from four more, DOE has arrived at the following tentative general findings:[27]

- customers have uniformly been found to respond significantly to changes in electricity prices at all hours of the day, including peak periods;
- peak period kilowatthour price elasticity (i.e., "responsiveness") appears to exceed off peak elasticity;
- time-of-use rates reduce residential customer peak demands even on the hot test days of the year; and
- customer attitudes toward time-of-use rates are decidedly positive.

More specifically, DOE has observed surprisingly uniform—and encouraging—results among the various time-of-use demonstration programs, even though the study designs varied considerably from test to test. Some studies metered consumption and demand during two different periods–onpeak and offpeak –while others employed at least one additional rating period, a "shoulder" or "intermediate" time of the day. The duration and the time used for each period varied according to different utilities' peakloads. While some time-of-day customers were compared with their own utility records from a year earlier, others were examined in comparison to groups of control customers with similar demographic, economic, and historical electricity consumption characteristics. The number of participating customers in each study ranged from fewer than 100 to several thousand. Some experiments lasted only a year, while others are continuing for up to 5 years. Finally, the ratios of onpeak to off peak rates differed substantially among the studies. Specific results of time-of-use tests in six States, dealing with kilowatthour consumption, kilowatt demand, and shifts among rating periods, are summarized in tables 57 and 58.

In a few cases, utilities attempted to estimate actual or potential effects of time-of-use pricing on their system loads and fuel costs. Connecticut Light & Power Company, for example, perceived an actual reduction in system peak of 8 to 13 MW in its peak winter month, and *70* to 83 MW in its peak summer month. Arkansas Power & Light projected a fuel cost saving of $20 million "over the short run" if the experimental rate design were to be implemented on a systemwide basis.

"''Electric Utility Rate Demonstration Program Fact Sheet," Economic Regulatory Administration, November 1977.

Table 57.—DOE Electric Rate Demonstration Program kWh Consumption Effects

State	Onpeak consumption	"Shoulder" period consumption	Off peak consumption	Net change in consumption
Arizona	T-O-D customers reduced, compared with same customers a year earlier		Increased slightly, compared with year earlier, according to inconclusive evidence	Inconclusive evidence suggests slight decline
Arkansas	T-O-D customers reduced to level 18-26% below control customers on average summer days, and 15-59% below control customers on system annual peak day			Slight decline on average summer days, larger larger decline on peak day
California	T-O-D customer reduced compared with same customers a year earlier		Increased, compared with year earlier	
Connecticut	T-O-D customers reduced "considerably" compared with control customers i.e., consumption 23% lower	T-O-D reduced to "sign if i cantly less" than control in summer, but consumed at same level in winter	T-O-D consumed "significantly more" than control in winter, same level as control in summer	T-O-D consumed 9-13% less than control in summer, was "not significantly different" in winter
Ohio	T-O-D customers reduced "considerably" compared with control customers		T-O-D consumption increased in winters; no noticeable change in other months	T-O-D customers consumed 3.5% less overall than control
Vermont	T-O-D customers reduced some compared with year earlier (amount not quantified)	(not quantified)	T-O-D increased some from year earlier	T-O-D increased about 3% compared with year earlier
Six-State summary	T-O-D customers reduced 15-30% compared with control customers or year earlier		T-O-D customers increased in comparison with control customers or year earlier	T-O-D consumed 5-8% less overall than control customers. Exception: Vermont, Most reductions occur in summer. Some increases occur in winter

Table 58.—DOE Electric Rate Demonstration Program kW Demand Effects

State	Daily peak hour	Monthly peak hour	Annual
Arkansas	T-O-D customers' diversified demand reduced 14-31% on summer days at peak hour		O D m d m d b 9 0
California	T-O-D customers reduced demand coincident with system peak from year-earlier patterns. Reductions reach 5-10%, with most attributable to a few large users		
		T-O-D residential customers' diversified demand "significantly" lower than control customers at hour of system monthly peak in every month of test	T-O-D customers' diversified demand 17% below control at annual system peak hour (January), and 41% below control at summer peak hour (June)
Ohio	T-O-D customers' diversified demand lower than control customers' at daily peak hours		T-O-D customers' diversified demand lower than control customers' at system annual peak hour and on hottest day of year.
Summary	T-O-D customers' diversified demand significantly below control	T-O-D customers' diversified demand 15-40% below control at hour of monthly peak, on average	T-O-D customers' diversified demand 15-40% below control at hour of annual peak, on average

Much analysis of the rate demonstration program data remains to be done, but the initial findings appear to confirm the usefulness of time-differentiated rates as means of encouraging more efficient, cost-effective electricity delivery. Evidence of consumer acceptance of such rates may well be among the more important observations to date. It should be emphasized, too, that long-term implementation of time-differentiated rates can be expected to produce greater consumer response than the present experiments. This is because short-term response relies almost entirely on behavioral changes in the usage rate and time of use of presently owned appliances, while long-term response could include widespread changes in capital stock, such as purchases of water heaters with timing devices to limit their operation to off peak hours.

DOE Load Management Activities

The Department of Energy encourages load management through a small program in the Department's Economic Regulatory Administration (ERA). DOE provides States with funds and technical assistance to advance current knowledge and experimentation with load management programs, and will monitor the States' compliance with the new requirements for consideration of Federal standards (including load management) in future ratemaking proceedings. The Department's Electric Energy Systems Division and Energy Storage Division also carry out research and development activities to assist the development of new load management technologies.

Conservation Programs of the Federally Owned Power Authorities

The federally owned segment of the electric power industry, which accounts for about 10 percent of the Nation's installed generating capacity and 5 percent of total kilowatthour sales, has always served as a "yardstick" for certain national policies. For most of the history of the two largest Federal power authorities–the Tennessee Valley Authority (TVA) and the Bonneville Power Administration — they have served as models for effective expansion of electricity service to rural areas at low cost. More recently, they have begun to function as models for programs in energy conservation.

The Tennessee Valley Authority encourages conservation among its customers in a number of ways. TVA offers consumers interest-free loans, payable over 3 years, for purchasing and installing insulation in their attics. The insulation program will soon expand to allow 7-year interest-free loans of up to $2,000 for a number of conservation measures, including storm windows, floor insulation, caulking and weather-stripping, and insulation of duct work. TVA will determine which measures are cost-effective for each customer and will inspect the installation before releasing funds. Additionally, TVA offers customers now using electric resistance heating systems a means of converting to heat pumps by providing 81/2-percent loans repayable over 10 years.

[n the area of rates, TVA asserts that its rate structure is based on cost of service and encourages conservation by applying automatic adjustment clauses only to that portion of a customer's electricity consumption that exceeds 500 kWh in any billing period. TVA is also experimenting with four different rate structures designed to encourage conservation. In one study, time-of-use rates are being applied, with kilowatthour consumption billed at 9 cents per kWh during onpeak periods and 1.5 cents per kWh during off peak periods. Analysis of the results of the study is just beginning.

The Bonneville Power Administration has concentrated its conservation efforts on its own Internal operations and on information dissemination among its employees, its utility customers, and end-users. The Bonneville outreach effort has included workshops on insulation, energy audits, and training sessions for CETA workers employed in weatherization programs. Bonneville has also undertaken certain research programs aimed at conservation; these include experimental use of aerial and ground-based infrared sensors to detect heat loss from buildings, and the installation of wind data recording stations to determine where wind-driven electric generator systems could be installed to supplement hydroelectric energy in the Bonneville service area. Bonnevine has not developed an insulation financing program or experimented with conservation-oriented rates.

Conclusions for Utility Policy

In response to the dramatically different circumstances in which utilities have had to operate in recent years, electric and gas companies are undertaking a number of new activities to encourage residential users to reduce their consumption and aid in leveling system peakloads. Because many of these activities — including energy audits, insulation programs, rate reforms, and load management — are recent in origin and used by only a relatively small number of companies, important areas of uncertainty about their efficacy remain to be clarified. The opportunities for encouraging conservation through utility actions appear promising, but the adjustments to new methods of operation are proving difficult in some cases for both the utilities and their customers.

The great diversity among the Nation's 3,500 electric utility companies and 1,600 retail natural gas distributors precludes the development of a single national policy for conservation. Rather, there must be a flexible approach enabling each utility to design a residential conservation program around its unique system load, supply and cost situation, climate, and other variables. An examination of Federal programs and opportunities suggests that recently enacted legislation and programs offer a good start.

THE FUEL OIL DISTRIBUTORS

The distribution of home heating oil, as an industry, was developed by oil appliance manufacturers and their retail installers. Today, nearly 80 percent of heating oil demand in the United States is served by independent fuel oil marketers.

Although the heating oil industry operates nationwide, about 90 percent of the heating oils are sold in only 28 States, principally along the northern tier of the United States from the Pacific Northwest to New England and down the east coast to Florida.[28] Over 16 million residential buildings depend on fuel oil for space heating.[29]

Historically, the fuel oil industry has not been regulated. In recent years, however, the industry has been subject to Federal regulations on pricing and allocation during periods of short supply. No such regulations are presently in effect.

Unlike the utilities with whom the industry competes for space-heating markets, most fuel oil marketers do not have captive customers, nor do they have a monopoly on product or service territory. The marketers are forced to compete within the oil industry for product supply, advantageous pricing, and customers. As marketers are in direct contact with the consumers, the success of their business depends entirely on customer satisfaction. One of the major concerns of fuel oil marketers is the need to maintain customer goodwill in light of national energy and conservation policies that could conceivably discriminate against fuel oil consumers and jeopardize the competitive position of the marketers.

Industry Size

In 1972, the Bureau of the Census of the Department of Commerce estimated that there were 7,276 fuel oil dealers with payrolls. This estimate, however; includes only those fuel oil dealers who list the sale of fuel as their principal business. However, in many markets, particularly nonurban markets, petroleum marketers may distribute both gasoline and heating

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[28] Sales of Fuel Oil and Kerosene in 1977 (Department of Energy, Energy Information Administration, 1978), p. 6.

[29] *Annua* Housing *Survey,* 7976 (Department of commerce, Bureau of the Census, 1978), p. 6.

oil, with gasoline predominant. According to industry estimates, the total number of fuel oil suppliers, including those who distribute more gasoline than fuel oil, falls between 10,000 and 12,000 marketers.

The predominant distillate oil consumed in residential space heating is No. *2* fuel oil. Heavier heating oils (No. 5 and No. 6 oil) are used primarily by industrial accounts, and are usually purchased directly from refineries or terminal facilities. Consumption of No. 2 fuel in 1977 amounted to 1.2 billion barrels.[30] No. 1 fuel oil (kerosene) and No. 4 oil are also used for space heating. The demand for these distillate oils in 1973-77 appears in table 59.

Fuel Oil Marketers

About 85 percent of independent heating-oil marketers sell directly to consumers. Therefore, they are regarded as retailers rather than jobbers. However, a dual petroleum marketer will often have different suppliers or brands for its heating oil and its gasoline. It is not unusual for a distributor to be a jobber for one product and a retailer of the other.

A marketer may service from several hundred to 50,000 or more customer accounts. According to a 1978 survey, 16 percent of the marketers had more than 3,000 customers; their share represented 55 percent of the customers recorded .3' Forty-seven percent of the companies had between 1,000 and 3,000 accounts, representing 41 percent of the customers. Forty-two percent of the marketers had fewer than 1,000 customer accounts, accounting for approximately 14 percent of the customers. The survey also indicated that all fuel oil marketers sold No. 2 fuel oil, about half sold No. 1 fuel oil (kerosene), and less than 10 percent sold other fuel oils. The survey indicated that about 80 percent of marketers sold and serviced oil heat equipment, accounting for 62 percent of that end of the business. Seventy-eight percent of the heating oil marketers surveyed operate a bulk plant (large storage) facility.

[30] *Sales of Fuel Oil,* op cit., p. 1.

[31] Margaret Mantho, "Margins Improve to Offset Rising Costs," *Fuel Oil and Oil Heat,* September 1978, p. 35.

Sales of Distillate Fuel Oils

Figure 17 represents sales of distillate fuel oil by end use sector for the period 1973-77. As indicated by the table, nearly 50 percent of all sales of distillate fuel oil goes to heating. The data presented does not indicate what percentage of total sales is earmarked for the residential sector. However, according to one DOE official, approximately 85 to 90 percent of No. 2 heating oil is sold in the residential sector.

In general terms, fuel oil marketers deliver more than 2 million barrels of distillate oil daily from November through March to meet residential space-heating needs. The delivery schedules are temperature-sensitive and established according to the calculated "degree days." The average consumption per heating season for residential home heating varies from about 900 gallons in the South-Atlantic region to about 1,600 gallons per heating season in the New England region.

Service Activities

For the 1977-78 heating season, about 67 percent of all fuel oil consumers had their oil heat equipment checked and serviced as part of annual efficiency checkups. About 40 percent of fuel oil consumers have service contracts providing for annual efficiency checkups. These annual service calls are generally considered essential to maintain furnace efficiencies and promote fuel conservation.

In the same heating season, the average serviceman was responsible for 440 customers and managed to make six calls per day, exclusive of efficiency checkups.[32] About 53 percent of the servicemen serviced burners exclusively. The remainder either installed burners only or serviced and installed them.

The lifetime of oil heat equipment is approximately 20 years while other equipment— such as gas furnaces — may be in place much longer. Improvements in oil burner efficiencies over the years have acted as an incentive for more rapid replacement of oil furnaces.

[32] Margaret Mantho, "Annual Service Management Analysis, " *Fuel Oil and Oil l-feat,* May *1978,* p. *36.*

Table 59.—Average Yearly Demand for Distillate Fuel Oil (in thousands of barrels)

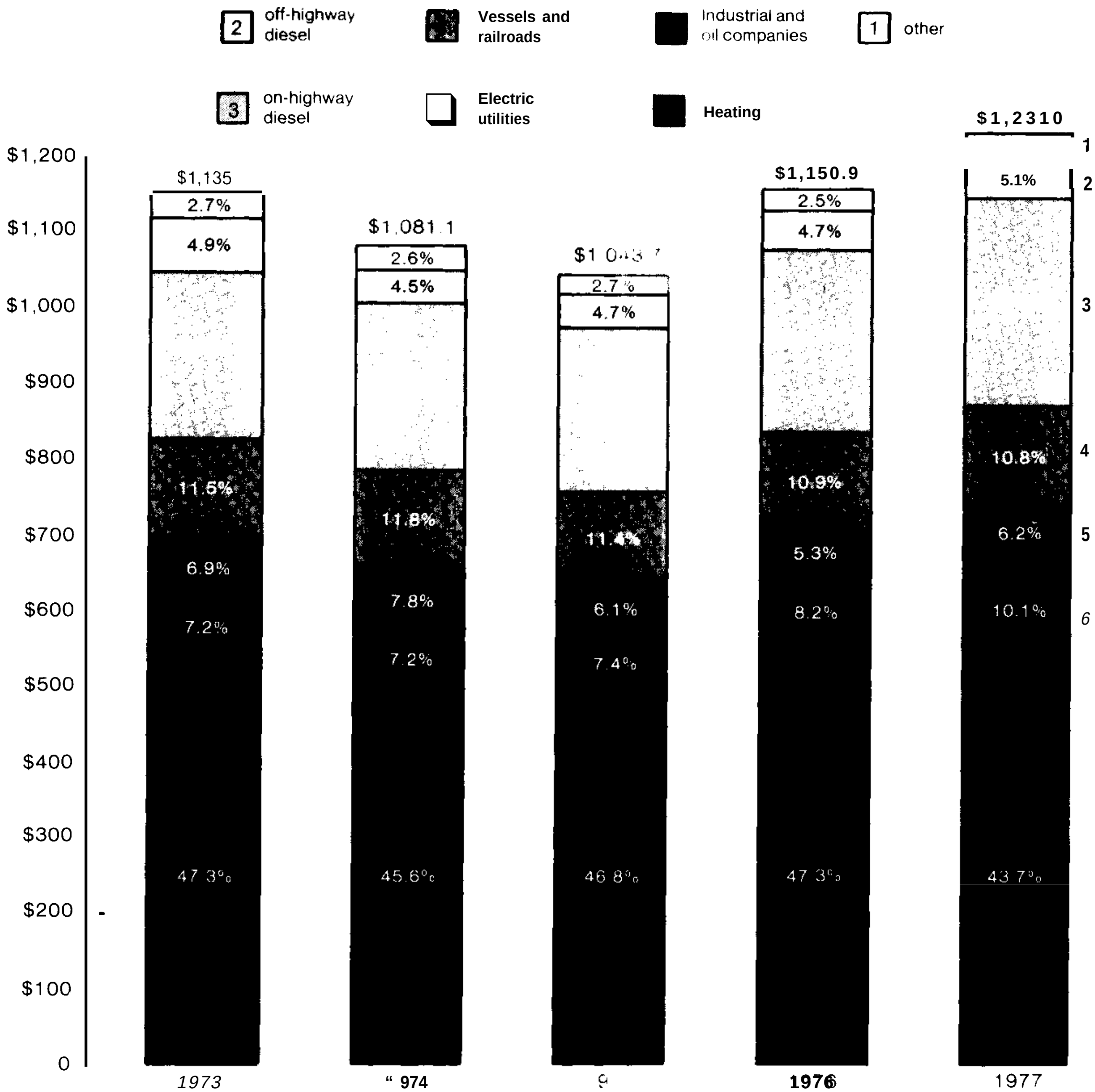
		Domestic demand	Production	Imports	Stocks
1972	Average	2,913	2,629	181	[a]154,284
1973	Average	3,092	2,820	392	[a]196,421
1974	January	3,835	2,880	464	181,179
	February	3,849	2,399	306	149,125
	March	3,164	2,226	287	128,822
	April	2,852	2,522	220	160,645
	May	2,450	2,704	268	141,806
	June	2,377	2,783	220	160,645
	July	2,309	2,792	221	182,458
	August	2,309	2,705	125	198,673
	September	2,385	2,552	152	208,269
	October	2,887	2,700	237	209,908
	November	3,157	2,801	454	212,875
	December	3,853	2,924	515	223,717
	Average	2,948	2,668	289	
1975	January	3,953	2,852	324	199,715
	February	3,967	2,679	302	176,696
	March	3,293	2,531	256	161,111
	April	3,094	2,486	110	146,214
	May	2,382	2,431	136	152,027
	June	2,266	2,574	68	163,306
	July	2,112	2,589	106	181,472
	August	2,173	2,592	92	197,323
	September	2,163	2,812	129	220,732
	October	2,675	2,744	103	226,113
	November	2,544	2,767	96	235,749
	December	3,778	2,783	124	208,787
	Average	2,849	2,653	153	
1976	January	4,298	2,734	164	165,428
	February	3,687	2,961	207	150,439
	March	3,336	2,793	151	138,306
	April	2,788	2,655	96	137,249
	May	2,519	2,738	97	147,057
	June	2,436	2,885	151	165,064
	July	2,255	2,959	126	190,861
	August	2,237	2,982	131	217,930
	September	2,618	2,947	147	232,230
	October	[c]3,028	2,995	141	235,599
	November	3,714	3,180	135	223,648
	November FEA/API	3,724	3,199	136	221,178
	December FEA/API	4,654	3,273	166	183,500
	Average FEA/API[c]	3,130	2,925	142	
1977	January FEA/API[c]	5.237	3,374	471	145.490

a Total as of December 31.
b 1976 average is based on Bureau of Mines data for January through November and FEA data for December
January 1977 data are from American Petroleum Institute (API).
c= Revised.

SOURCES: Bureau of Mines, Federal Energy Administration, and American Petroleum Institute.

New burners installed today are expected to operate at seasonal efficiencies of 80 percent, and new promising technologies have produced burners with seasonal efficiencies up to 84 percent. To date, there has been little Federal support for development of high-efficiency oil heat equipment. Furthermore, most marketers cannot afford to establish R&D programs

Figure 17 --Sales of Distillate Fuel Oil Use as Percent of Total (millions of dollars]



SOURCE: "Fuel Oil Sales, Annual," *Energy Data Reports* prepared by the Energy Information ... Department of Energy, November 1978, p. 2

for high-efficiency equipment; research efforts are therefore centered in the furnace manufacturing industry.

New Construction

In *1971-77,* **from 8 to 11 percent of new homes were heated by oil. The following chart compares the relative position of oil, gas, and electricity in the new home market:**

Percent of New Homes by Type of Heating Fuel[33]

	Oil	Gas	Electricity
1971	8	60	31
1972	8	54	36
1973	10	47	42
1974	9	41	49
1975	9	40	49
1976	11	39	48
1977	9	38	50

In the Northeast, however, the figures indicate an increase in the oil share of the new home market in *1971-76.* **The following chart shows the comparisons for the Northeast:**

Percent of New Homes by Type of Heating Fuel[34]

	Oil	Gas	Electricity
971	31	42	26
972	33	36	29
973	35	34	28
974	32	29	38
975	41	24	33
976	51	15	31
977	49	17	31

Thus, while oil heat has grown slowly in the national new home market, still accounting for only slightly over a tenth of the units, oil heat in new homes in the Northeast has grown from just under a third of the market in 1971 to over half in 1976. The decline of the gas share in the early- to mid-1 970's, both nationwide and in the Northeast, can be attributed to prohibitions on new gas hookups by several State public utility commissions in response to supply shortages. Recent increases in gas supply and termination of moratoria on new hook-ups may reverse this trend.

[33] *Characteristics* of New *Housing* 7977 (Department of Commerce, Bureau of the Census, 1978), p. 28.

[34] I bid.

The Role of Oil Heat Distributors in Energy Conservation Practices

Introduction

Given the relatively small and highly concentrated nature of the residential oil-heating market, a number of factors affect— and limit — the role of fuel oil distributors in residential energy conservation. This section outlines the industry's assessment of its current role in the energy conservation practices of its customers. The assessment is the product of a questionnaire that was mailed to 48 fuel oil distributors and 19 State, regional, and local trade associations in late November 1977. Twenty-one distributors and five trade associations responded from all regions of the country where fuel oil is consumed for space heating.

Marketing of Energy Conservation Products

Very few fuel oil distributors are actively selling residential insulation, storm windows and doors, and other conservation hardware. However, most fuel oil distributors are involved in helping their customers reduce the amount of fuel oil consumed. As mentioned earlier, about 69 percent of the residential consumers of fuel oil have their heating equipment checked and/or tuned at least once a year through a direct service offered by the distributors and many of the refiner markets.

More fuel oil distributors use independent contractors to provide insulation and other energy conservation products to their customers than sell these materials directly.

Besides the basic energy hardware (e.g., replacement burners, boilers, furnaces, insulation, etc.) that is being marketed by fuel oil distributors, some have attempted to market other energy conserving equipment such as automatic stack dampers, stack heat reclaimers, outdoor temperature controls, humidifiers, attic vents, fireplace heaters, and other related items.

Reduction in Annual Fuel Consumption

More than half of the respondents reported that 50 percent or more of their customers have reduced their annual consumption by

more than 15 percent since the 1973 price rise. States in the colder climates reported the highest percentage of customers conserving fuel oil.

In the 1972-73 heating season (adjusted for actual rather than average degree days), residential oil consumption reflected predictable regional patterns, influenced by climate—for example, a low of 800 gallons in South Carolina to a high of 1,750 gallons in northern New England. It should be noted that homeowner consumption can vary widely even within a community. This divergence is largely attributed to variables such as living-space size, thermal characteristics of the housing unit, and consumer behavior patterns.

Factors That Influence and Limit Market Entry

Why have a few fuel oil distributors entered the business of marketing insulation and storm windows and doors, while most have not? The reasons most often cited include the expectations of increased profits, increased service of existing customers, and the prevention of customer switches to other fuels.

What prevents fuel oil distributors from marketing insulation and other related items? Reasons most frequently cited include the lack of available qualified independent contractors to service the distributor's customers, and the lack of capital to get into the conservation business. Furthermore, most competing distributors are simply not marketing this hardware. Other disincentives include the apparent shortage of insulation and other energy materials, the inability of homeowners to pay for or finance energy conservation measures, and the limited public interest in energy conservation.

Advertising is one of the major vehicles by which fuel oil distributors penetrate the market. Bill-stuffers are the most popular form, accounting for 5 to 30 percent of total advertising budgets. Direct mail to potential customers runs from a low of 10 percent to a high of 90 percent of advertising budgets. Radio is also used, but it accounts for a relatively low percentage of the total advertising budget.

A number of marketing choices that are exercised by fuel oil distributors are based on technical information about energy conservation. Some of the most frequently cited sources include State trade associations, magazines and other publications of general circulation, and local industry trade associations Suppliers and manufacturers of energy conservation materials, however, are considered the most reliable sources of technical information

Fuel Oil Customer Accounts

Since 1973, when costs of fuel oil began to rise, oil distributors' delinquent customer accounts (past due by more than 30 days) have increased significantly. Many distributors reported increases of about 15 percent or greater, and some distributors have reported an increase in delinquent accounts by 50 percent or more. Obviously, customers with delinquent accounts cannot normally finance additional expenditures, such as conservation improvements. A large number of delinquent accounts affects the ability of distributors to set aside capital or to acquire financing for the purpose of developing energy conservation guidelines.

One of the most significant problems facing fuel oil distributors in terms of their ability to carry delinquent accounts or to offer credit terms for financing conservation efforts is the elimination by wholesale suppliers of discount terms for payments. Another problem frequently cited is the increased interest charges associated with financing more expensive inventory. Furthermore, increases in insurance costs have also contributed to oil distributors' cash flow problem.

TECHNICAL NOTES–COMPUTER SIMULATION: THE EFFECT OF CONSERVATION MEASURES ON UTILITY LOAD FACTORS AND COSTS

The Question

Will widespread adoption by residential electric customers of conservation measures, particularly insulation, result in utility load changes that are economically counterproductive to the utilities and/or their customers?

Background

Many residential consumers of electricity are investing in energy-saving materials and devices for their homes in hopes of reducing their utility bills, or at least stemming the rapid increases they have experienced recently. Adding insulation to existing homes is the action most commonly taken, but some homeowners — and builders of new homes— are also choosing HVAC systems with energy efficiency and cost savings in mind. Electric heat pumps are becoming widely used for this reason. Consumer attitudinal surveys indicate that electric customers investing in conservation measures are motivated primarily by the hope of saving money.

Whether or not consumers experience lower or even slower growing utility bills in the future depends ultimately on whether or not their utility companies can achieve cost savings that can be passed on, in turn, to ratepayers. Many factors affect utility costs, and consumer conservation actions will not be the only determinant of the direction in which rates will go in the next few years. But utility managers have raised questions about the possibility that conservation practices could have some adverse effect on load factors and systemwide costs, thereby contributing to a need for higher rates. From the consumer's standpoint, this would surely be the ultimate example of "Catch-22."

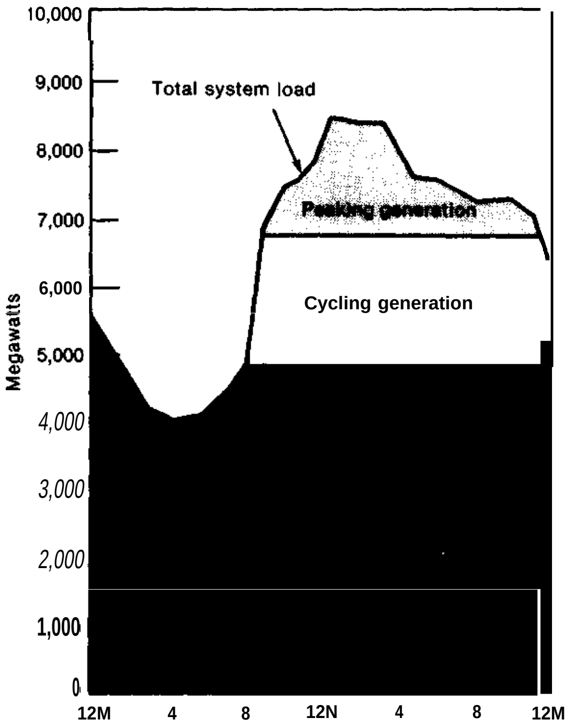
The fear of cost increases caused by conservation actions is based on the fact that utility costs are positively correlated to seasonal and daily variations in the demand for electricity, and on the possibility that insulation and other conservation measures could magnify these variations in uneconomic ways. Electric companies must have available to them at any given time enough generating capacity to meet the highest level of demand expected at that time, plus a reserve margin of capacity to use in the event that some powerplants are shutdown by emergencies or for routine maintenance. But since the peak demand level may be reached on only a few days each year, and for only a few hours even on those days, utilities are likely to have a considerable fraction of their total generating capacity idle much of the time.

Idle generating capacity is expensive, and certain kinds of powerplants are more expensive to keep idle than others. Although a company pays for fuel and other operating costs only when the plant is operating, many fixed costs ⁻ such as interest on the capital borrowed to build the plant— must be paid regardless of how much the plant is used. It follows, then, that newer, bigger, more capital-intensive plants (particularly nuclear plants) are the most expensive to shutdown, while older, smaller plants (like oil-fired turbines) are the least expensive to hold in reserve. Conversely, new plants are often the least expensive to operate, while the older ones (which usually use the most expensive fuels) are the most costly to run.

A utility's daily or yearly "load' '-the total amount of electricity it must generate during that time— is usually thought of as having three components. The baseload–-that which is demanded nearly all the time— is the largest component and is usually generated with the company's newest, largest, and most technologically advanced plants. The intermediate load–an increment that is demanded less of the time— is typically derived from slightly older and smaller plants, fired with fossil fuels.

The peakload — a sharply greater demand component that may be demanded only occasionally — is usually met with small oil- or gas- fired turbines, or with pumped-storage hydroelectric plants, or by purchasing power from other companies sharing the same distribution grid. Figures 18 and 19 illustrate a typical system load and the three major generating components.

Figure 18.—Dispatching Generation to Meet a Cyclical Load

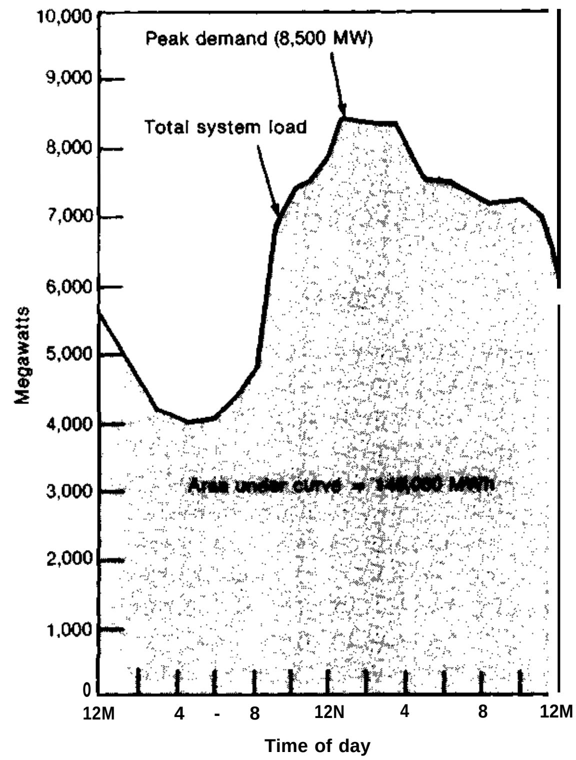


SOURCE: Electric Utility Rate Design Study, *Rate Design and Load Control: Issues and Directions,* **a** Report to the National Association of Regulatory Utility Commissioners, November 1977

The costs of keeping and operating these different kinds of plants vary, typically, as follows:

- **Baseload plants–high fixed costs, low operating costs, resulting in the lowest overall costs when in operation.**
- **Intermediate-load plants— medium fixed costs, medium-to-high operating costs, resulting in medium overall costs when in operation.**
- **Peakload plants — low fixed costs, very high operating costs, resulting in the highest overall costs when in operation.**

Figure 19.— Daily Load Curve



$$\text{Daily load factor} = \frac{\text{daily energy}}{\text{24 hr X peakload}} = \frac{\text{149,000 MWh}}{\text{24 hr X 8,500 MW}}$$

$= 0.73 = 73\ \%$

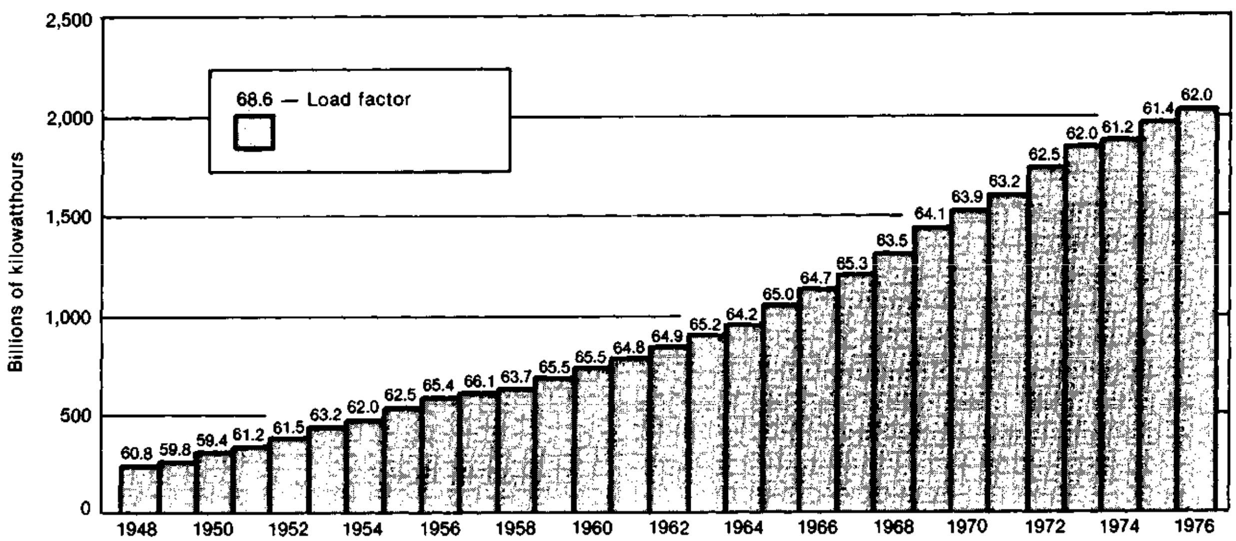
SOURCE. **Electrlc Utility Rate Design Study,** *Rate Design and Load Control: Issues and Direct/ens,* **a Report to the National Association of Regulatory Utility Commissioners, November 1977.**

A major determinant of total utility costs and generating capacity needs is a company's "annual load factor, " which is the ratio of the average utility load over the year to the peakload during any time period (usually 15 minutes] during the year. The higher the load factor, the less total downtime the company experiences in its generating capacity. Up to a certain point, the utility benefits from keeping its plants running, generating sales revenues with which to cover both fixed costs and operating costs. Some idle capacity is needed, however, to allow normal maintenance operations to take place, to substitute for other plants in emergency outages, and to meet the peaks. When all plants are operating and additional

power is being purchased, operating costs are very high. It is desirable, in other words, to balance the load factor properly so that base plants keep running, intermediate plants take up the gaps caused by planned and unplanned interruptions, and peaking plants are used as little as possible.

A typical load factor, and one which accomplishes this goal reasonably well, is in the neighborhood of 0.65, or an average use of 65 percent of capacity. Figure 20 shows average annual load factors and total electricity output for U.S. utilities between 1948 and 1976.

Figure 20.—Electric Energy Output and Annual Load Factors



SOURCE: Electric Utility Rate Design Study.

Note: Figures shown are for the total electric utility industry of the contiguous United States.

OTA Analysis of Conservation Impact on Utility Loads and Costs

A model developed for OTA's recent study, *Application of Solar Energy to Today's Energy Needs,* analyzed the impact of conservation measures on utility operations.

OTA's model simulates utilities in four U.S. cities. The utility loads, shown in table 60, consist of a mix of single-family homes, townhouses, low- and high-rise apartments, shopping centers, industry, and streetlighting. Each of the four cities has the same number of units although the heating and cooling loads are determined by the weather conditions, taken from 1962 data, of each city. The residential heating and cooling equipment mix is initially set to match conditions in 1975 and then forecast. to 1985 using a residential energy use model developed by ORNL. All the single-family homes are initially set to the same level of Insulation, which the model can increase to a higher value. The insulation levels in the other buildings do not vary. The change for single-family homes corresponds to a heat load reduction of 31 to 49 percent, depending on the location. In addition to the insulation level, the type of heating equipment can be changed to allow the possibility of varying the percentage of homes that are electrically heated. Diversity is built into the model so that the peakloads of the individual homes do not all occur simultaneously. 35

To determine the effects on utility loads of increased insulation among residential

[35] Further details about the model and the hypothetical utility loads can be found in *Application of Solar Energy to Today's Energy Needs,* vol. 1, chapter V, and vol. 11, chapter V 1.

Table 60.—1985 Projection of Heating Unit Mix and Basic Loads (number of buildings)

	Albu-querque	Boston	Fort Worth	Omaha
Single family units				
Electric heat.	10,470	8,080	11,790	7,720
Fossil heat.	45,450	47,840	44,130	48,200
Electric cooling. . .	43,613	34,863	55,920	55,920
Total	55,920	55,920	55,920	55,920
Townhouses	6,960	6,960	6,960	6,960
Low rise units	2,160	2,160	2,160	2,160
High rise units.	600	600	600	600
Shopping centers . . .	30	30	30	30

Annual industrial loads (all cities) —2.54 billion kWh.
Annual streetlight load (all cities) —98.78 million kWh.

customers, the model was run first with all single-family homes at the baseline insulation level and again at the high insulation level, using the forecast *1985* mix of home heating systems initially, and then using an assumption that 50 percent of the homes were electrically heated. (The latter case was included to simulate utilities with winter peaks.) All other load characteristics remained constant throughout the analysis. The heating and cooling mix for single-family homes for the *1985* forecast is shown in table 60. Table *61* shows the numbering of buildings assumed to have electric heat in the case when it was assumed that 50 percent of residences use electric heat.

Results

The load factor and seasonal peak demands are given in table 62 for the reference and the high insulation cases for both mixes of residential heating —1 *985* projection and high electric resistance. ***The results*** *show that an increase in insulation does not change the load factor significantly.* In all but two situations, the load factor Increases as insulation is added, but the increase does not exceed 4 percent. The two exceptions are the utilities with 50-percent electric resistance heat that still experience their peak loads in the summer.

Table 61.—50-Percent Electric Resistance Heating by 1985 (number of buildings)

City	Electric heat	Fossil heat	Total
Albuquerque, Boston, Fort Worth, and Omaha	27,960	27,960	55,920

Table 62.–Simulated Utilities' Load Factors, Peaks, Summer-Winter Ratio by 1985

	Albuquerque		Boston		Fort Worth		Omaha	
	Reference case	High insulation	Reference case	High insulation	Reference case	High insulation	Reference case	High insulation
Base case								
Load factor.	0.534	0.537	0.498	0.505	0.470	0.475	0.448	0.453
Winter peak (MW,	1,359	1,315	1,316	1,263	1,562	1,472	1,453	1,397
month).	Jan.	Jan.	Feb.	Feb.	Jan.	Feb.	Feb.	Feb.
Summer peak (MW,	1,386	1,352	1,354	1,320	1,942	1,873	1,823	1,768
month).	Aug.	Aug.	Jul.	Jul.	Aug.	Aug.	Jul.	Jul.
Summer-winter ratio . .	1.02	1.03	1.03	1.05	1.24	1.27	1.25	1.26
50-percent electric resistance heating case								
Load factor.	0.472	0.485	0.466	0.492	0.483	0.481	0.483	0.467
Winter peak (MW,	1,677	1,569	1,600	1,433	1,842	1,594	1,787	1,603
month).	Jan.	Jan.	Feb.	Feb.	Jan.	Jan.	Feb.	Feb
Summer peak (MW,	1,368	1,348	1,392	1,362	1,958	1893	1,847	1,805
month).	Aug.	Aug.	Jul.	Jul.	Aug.	Aug.		
Summer-winter ratio . .	0.79	0.86	0.87	0.95	1.06	1.19	1.03	1.13
50-percent heat pump case								
Load factor.	0.465	0.484	0.446	0.483	0.470	0.476	0.463	0.457
Winter peak (MW,	1,632	1,528	1,587	1,426	1,778	1,569	1,787	1,599
month).	Jan.	Jan.	Feb.	Feb.	Jan.	Jan.	Feb.	Feb.
Summer peak (MW,	1,373	1,351	1,400	1,368	1,976	1,906	1,861	1,815
month).	Aug.	Aug.	Jul.	Jul.	Aug.	Aug.	Jul.	Jul.
Summer-winter ratio . .	0.85	0.88	0.88	0.96	1.11	1.21	1.04	1.14

The effect on the summer-winter peak difference, shown in table 62, is more pronounced. For all summer peaking utilities, for either mix of heating systems, the ratio of the summer to winter peak increases as a result of increased insulation. These increases range from 1 to 12 percent and are greatest for the utilities with the highest percentage of electric heat. For the winter peaking utilities, the ratio decreases by about 8 percent when the residential insulation level is increased.

Discussion

These simulations indicate that the effect of extensive additions of insulation by residential customers depends greatly on the amount of residential electric heat in the utility's load, since adding insulation affects heating loads more than cooling loads. Utilities that have winter peaks or small electric heat loads (relative to their cooling loads) experienced increases in their load factors; this means that their peakloads were reduced more than their average loads by the addition of insulation. On the other hand, two of the simulated utilities — those with summer peaks accompanied by large electric heating loads–experienced moderate drops in their load factors after insulation was added. Summer-winter peak ratios change very little — under 2 percent— in the cases for which the electric heating load is small, but as that load increases, the change in the ratio also grows until the winter peak begins to exceed the summer peak.

In sum, OTA's simulation indicates that most utilities will not be measurably affected by the widespread addition of insulation by residential customers, unless at least a third or so of their residential customers use electric heat If more than half use electric heat, the utility will still experience an improved load factor as long as its peak comes in the winter. In such cases, the increase in load factor and the leveling of differences between summer and winter peaks can assist in bringing about more efficient use of generating capacity.