Chapter 5

Conventional Technologies for Electric Utilities in the 1990s

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Chapter 5

Conventional Technologies for Electric Utilities in the 1990s

INTRODUCTION

The financial difficulties faced by utilities in the 1970s and early 1980s have prompted many to investigate extending the lives of existing facilites or even rehabilitating old plants to yield additional capacity. Control of electricity end use has also surfaced as another promising alternative to meeting all or part of future load growth. For most of these utilities, however, conventional central station powerplants still provide the base against which all other supply-enhancing or demand-controlling investments are compared.

This chapter presents a benchmark set of cost and performance estimates for conventional options of traditional central station powerplants and for a variety of options which extend the lives or otherwise improve the performance of existing generating facilities. Since these strategic options are not the principal focus of this assessment, these estimates are presented primarily to enable comparisons with the new generating options discussed in chapter 4. These comparisons are reported in chapter 8. In addition, load management, one of the strategic options being pursued aggressively by utilities in many regions of the United States for controlling end use of electricity, is discussed in this chapter.

PLANT IMPROVEMENT AND LIFE EXTENSION

Introduction

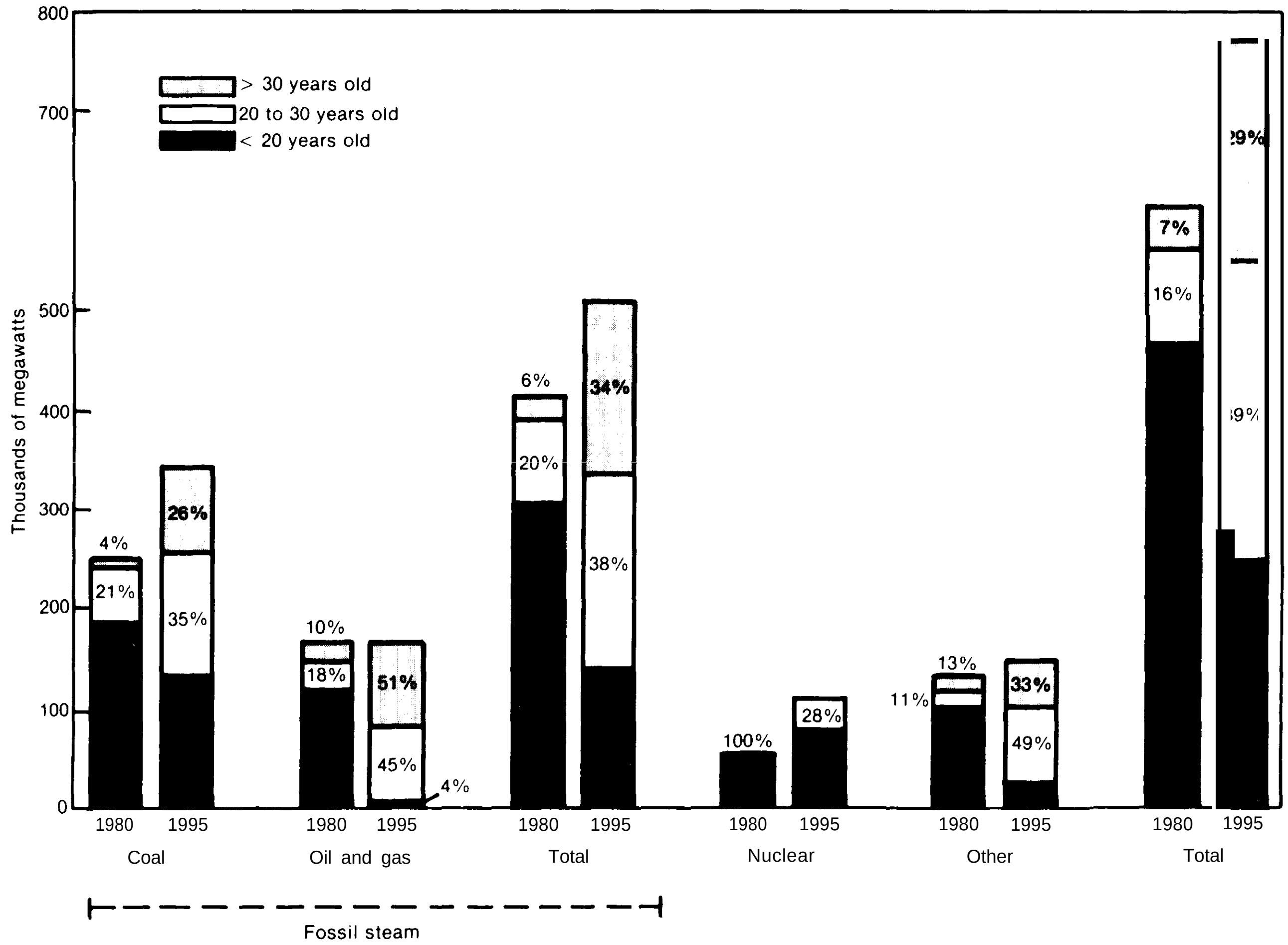
In the wake of declining demand growth and soaring costs of new generating capacity, many utilities have begun to examine the so-called **plant betterment option for improving the performance of or extending** the lives of existing capacity.[1] This option is likely to become increasingly important through the end of this decade and into the 1990s—a period when the U.S. powerplant inventory will undergo dramatic changes. For example, since 1975, new plant order cancellations nationwide by utilities have exceeded new plant orders. By the year 1995, if present new plant ordering patterns continue about a third of the existing fossil steam generating capacity in the United States will be more than 30 years old (see figure 5-1 and table 5-1). The age distribution varies considerably by region, however, as discussed in chapter 7. Moreover, the plants "coming of age" during this period will be considerably more valuable than those of early vintages. In the 1950s, unit sizes grew to over 100 MW and heat rates fell to below 10,000 Btu/kWh while older units(1920s and 1930s vintage) were much smaller with heat rates of as high as 20,000 Btu/kWh.[2] While in the past, the benefits of new technology far outweighed plant betterment options, because of the relative quality of currently existing plants, this situation is rapidly changing.

Traditionally, investments in aging fossil plants began to decline after about 25 years causing reliability to deteriorate accordingly. The plants were relegated to periodic operation, reserve duty, and, finally, demolition. For the remainder

[1] R. C. Rittenhouse, "Maintenance and Upgrading Inject New Life Into Power Plants, " *Power Engineering,* March 1984, pp. 41 -50; T. Yezerski, Pennsylvania Electric Association Power Generation Committee, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co., " unpublished paper, Sept. 18, 1984; R. Carelock, Potomac Electric Power Co., "Plant Life Extension: Potomac River Generating Station, " unpublished paper, September 1984.

[2] R. Smock, "Can the Utility Industry Find a Fountain of Youth for Its Aging Generating Capacity?" *Electric Light and Power,* March 1984, pp. 14ff.

Figure 5-1.—Age of U.S. Electric Power Generating Facilities, 1980-95



SOURCE: Office of Technology Assessment; prepared from data provided by E. H. Pechan & Associates, 1984

Table 5-1.—Average and Weighted Average Age of U.S. Electric Power Generating Facilities, 1984

Type of unit	Number of units	Total capacity (MW)	Average age (years)	Weighted[a] average age (years)
Coal steam	1,352	255,197	23.6	13.2
Oil steam	794	99,175	28.9	17.9
Gas steam	823	63,708	27.4	17.4
Lignite steam	38	11,382	16.9	5.9
Nuclear	91	72,736	7.2	5.8
Combined cycle	86	6,788	8.8	7.5
Oil peaking	839	31,199	11.2	10.2
Gas peaking	208	6,453	11.7	9.7
Internal combustion	2,302	3,922	27.2	22.1
Hydro	2,642	64,788	45.7	24.1
Pumped hydro	130	14,436	11.4	8.1

[a]Weighted by installed generating capacity in megawatts.

SOURCE: Robert Smock, "Can the Utility Industry Find a Fountain of Youth for Its Aging Generating Capacity?" *Electric Light and Power*, March 1984, pp. 13-17 of this decade, as new nuclear base load plants come on-line, existing base load fossil units will increasingly be relegated to cycling duty which can significantly shorten plant life. Recent studies, however, show that in many cases, such plants, at least those built in the 1950s and 1960s, can be refurbished cost effectively for $200 to $400/kW, even in cycling duty applications.[3] These studies also indicate that some refurbishment projects can include efficiency improvements, and capacity upgrades of 5 to 10 percent.[4]

Finally, many siting and environmental requirements facing new capacity can be avoided by rebuilding existing capacity. Table 5-2 shows the marked contrast in these requirements for new versus existing coal-fired units. Current Federal regulations (New Source Performance Standards—NSPS) require that any unit that is more than 50 percent rebuilt (defined as 50 percent of the cost of a *new* boiler) must reduce sulfur dioxide emissions by 90 percent of the uncontrolled level. It turns out that a great deal of plant betterment can be accomplished under this 50 percent requirement. Moreover, an important consideration with this requirement is that the emissions reduction strategy for the unit must be "practical."[5] Utilities assert, in some cases, that if the NSPS requirement were applied, life extension and plant betterment options would not be practical, i.e., cost effective, because scrubber backfits would be necessary.[6] We discuss these considerations later.

Objectives of Plant Betterment Options

It is important to note that plant betterment is only a substitute for new capacity to the extent plant retirement can be deferred past the time originally scheduled, and the plant's capacity can be increased as a result of betterment. When these conditions prevail, plant betterment options offer considerable promise[7] relative to other strategic options. However, they present a complicated planning problem for utilities. Indeed, a considerable investment is often required to develop the details of a prospective project and its expected cost. For example, in 1984 Wisconsin Electric Power Co. commissioned detailed plant

[3] Gibbs & Hill, Inc., "Considerations for Power Plant Life Extension: Prospects for the 1990s," contractor report to OTA, October 1984.

[4] R. Smock, "Operating Unit Heat Rates Can Be Cut, Says EPRI; New Units Can Be 10 Percent More Efficient," *Electric Light and Power,* March 1984, p. 24.

[5] The regulation reads that an existing facility falls under theses guidelines provided "it is technologically and economically feasible to meet the applicable standards set forth in this part."

[6] "Power Plant Life Extension Economics, Plans Explored at American Power Conference," *Electric Light and Power,* June 1984, pp. 27-30.

[7] One indication that this promise is already being realized is that average plant availability of existing units in the United States has increased from 67 percent in 1977 to 76 percent in 1984, partially as a result of plant betterment activities.

Table 5-2.—Environmental Requirements for Existing and New Plants

Particulate	Air emissions SO_2	NO_X	Condenser cooling water	Ash disposal	Wastewater treatment
Existing plants (1980 typical plants):					
Varies from 0.12 to 0.25 lb/MMBtu	3.2 lb/M MBtu. Compliance based on coal analysis	1.3 lb/M MBtu. No monitoring required	Thermal limits based on ecological studies	Sluicing and ponding of combined fly and bottom ash	Combining waste streams (coal pile, broiler cleaning, etc.) for cotreatment in ash pond
***New plants >73** MW:*					
0.03 lb/MMBtu 20% opacity Requires baghouse or very efficient electrostatic precipitator	1.2 lb/M MBtu and 90% reduction except 700/0 if emission <0.06 lb/M MBtu. Compliance based on continuous monitors. Requires coal cleaning or wet scrubber (total capital = $248/kW)	0.6 lb/MMBtu and 65% reduction. Compliance based on continuous monitors	Cooling towers	Dry collection and reuse or landfilling of flyash. Sluicing and pending of reuse of bottom ash	Dedicated possible separate treatment pond(s) may require artificial liner(s) and chemical addition

SOURCE W Parker, "Plant Life Extension—An Economic Recycle," *Power Engineering*, July 1984, and Judi Greenwald, U S Environmental Protection Agency, personal correspondence with OTA staff, June 18, 1985 betterment studies on a number of existing fossil units, at a cost of more than $1 million per study.

In considering plant betterment or life extension programs, utilities need to account for both system level objectives, such as coordination with existing capacity expansion and scheduled maintenance plans, and unit level objectives, such as extending the life for a target number of years at a specified level of capacity, efficiency, and availability. Indeed, the overall characteristics of a utility's system dictate the timing and level of investment justified in a particular betterment/life extension project. For example, a utility with a high reserve margin may consider the relatively simple step of derating an aging unit to lengthen its life, while a utility with a low reserve margin may consider upgrading the unit to both extend its life and increase its capacity. Although the age of the unit and the production lost during rebuilding may make the latter strategy more costly than life extension alone, usually it is still much less expensive than building new capacity.

Ultimately, all individual improvements relate to either increased productivity or longevity. **Productivity improvements involve increased efficiency; increases (restoration or upgrading)** in rated capacity; reduced fuel costs (e.g., through fuel switching); reduced labor requirements; increased capacity factors; and reduced emissions. *Longevity improvements* include mechanisms for increasing plant life at specified levels of rated capacity. This may mean extending the life of a unit at full rated capacity or, by contrast, "mothballing" the unit for use at a later time when all or part of the rated capacity is needed; mothballing is sometimes referred to as an extended cold shutdown.

Virtually all life extension/plant improvement programs begin with a detailed performance test of any candidate plant to determine the current status of the equipment, i.e., how far the current plant operating parameters are from the original design specifications. Equipment evaluated in the performance test includes the turbine generator, boiler, condenser, feedwater heaters, auxiliary equipment systems, flue gas cleaning equipment, and plant instrumentation. Comparison of the most recent performance test with historical performance identifies areas to be investigated in more detail. A detailed examination of the boiler usually precedes other studies since its results are likely to control the length of the overall plant betterment project being considered. Also, other areas of the overall study may be affected if, for example, the boiler analysis reveals that it must be operated at lower pressure to lengthen its life.[8]

Recommendations resulting from a detailed performance test and analysis, sometimes termed a design change package (DCP),[9] generally fall into two categories: 1) new procedures for startup, operations and maintenance, training of personnel, update of performance records, and spare parts support; and 2) equipment or component modifications. The category (1) improvements are usually relatively low cost and very cost effective. The nature of the category (2) improvements depends on the age of the equipment and the facility.

Likely plant betterment candidates are middle-age generating units (1 O to 20 years old) which, at some point in their lives, are usually relegated to intermediate duty cycling where they experience greater load changes, and more frequent starting and stopping, As noted earlier, this change in operation can significantly reduce the operating life of the unit and, as a result, upgrading of middle age units often means adapting them for cycling duty. Typical enhancements include full flow lubricating oil systems, automatic turbine controls, and thermal and generator performance monitors (newer units will also benefit from these improvements). In addition, the middle-aged units will benefit from turbine modification and temperature control equipment.

Upgrading or life extension of older units (20 years or more) usually requires evaluating the replacement of major components such as turbine rotors, shells, and generator coils. While uprating of components, such as the turbine, may be possible for older units, it is usually a highly

[8] S. J. Schebler and R. B. Dean, Stanley Consultants, "Fossil Power Plant Betterment," paper presented at Edison Electric Institute Prime Movers Committee Meeting, New Orleans, LA, Feb. 1, 1984.

[9] W. O'Keefe, "Planning Helps Make Plant Improvements More Effective," *Power,* February 1984, pp. 89-90.

customized job. **Table 5-3 shows a typical turbine generator uprating checklist which gives the possible limitations on a candidate upgrading** program. Figure 5-2 shows the possible improvements in heat rate of an upgraded (uprated and restored) turbine-generator unit.

The complexity of performance testing and analysis has prompted the major equipment manufacturers to offer comprehensive plant modernization programs.[10] Both manufacturers and architect-engineering firms see plant betterment projects as a promising market for their goods and services.

Finally, some plant improvement projects may be aimed at reducing emission levels or the use of specific fuels. For example, many projects in recent years have been carried out to convert oil-fired capacity to coal. Such conversions often involve unit derating, but recent studies show that recovering as much as two-thirds of the capacity lost after coal conversion can be achieved at 40 to 50 percent of the dollars per kilowatt coal conversion cost.[11]

[10] For example, Westinghouse has been marketing turbine-generator upgrades for several years.

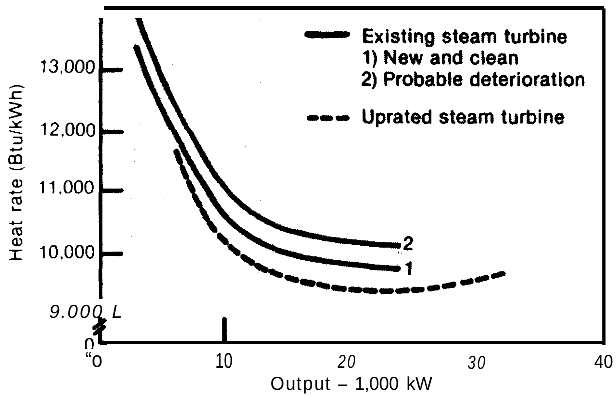
[11] P. Miliaras, et al., "Reclaiming Lost Capability in Power Plant Coal Conversions: An Innovative Low-Cost Approach," *Proceedings of the Joint Power Conference*, American Society of Mechanical Engineers, 1983, 83-J PGC-Pwr.

Table 5-3.—Turbine Generator Uprating Checklist

1. Additional plant steaming capability:
   - Boiler flow, pressure, and temperature
   - Condenser flow and vacuum
   - Feedwater heater train pressures and flow
2. Additional electrical capability:
   - Breakers
   - Distribution system
   - Protective devices
3. Generator capability:
   - Field and armature temperatures
   - Actual cooling water temperature
   - Present condition
   - Exciter capability
4. Turbine uprating capability:
   - Casing limitations
   - Exhaust bucket limitations
   - Modification packaging
5. Uprating effects on system efficiency:
   - Design improvements
   - Restorations effects
   - Part load effects

SOURCE: T. Yezerski, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co," briefing presented to Pennsylvania Electric Association Power Generation Committee, Hershey, PA, Sept. 18, 1984.

Figure 5-2.—Heat Rate v. Generator Output for Uprated and Restored Turbine-Generator Set



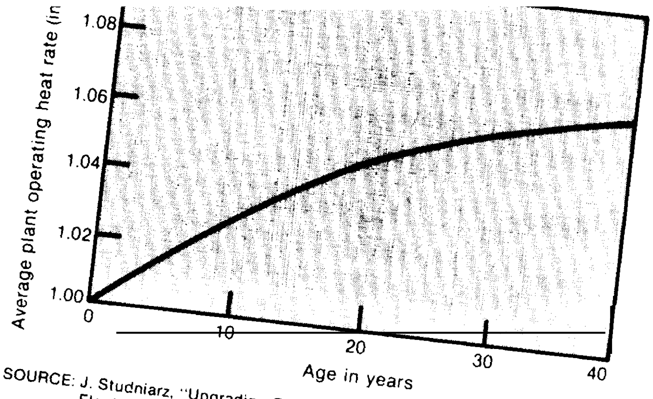
SOURCE: Westinghouse Electric Corp., "Power Plant Life Extension, Renovation & Uprating Workshop," presented to American Public Power Association, Omaha, NB, May 22-24, 1984.

Relative Cost and Performance

The principal effects of fossil powerplant aging are: 1) decreased efficiency, i.e., the amount of electricity generated per Btu declines as plant heat rate increases, and 2) more and longer forced outages. Figure 5-3 shows the rate of increase in heat rate as a function of age for a typical fossil plant; the average is about 0.3 percent per year with average maintenance practices.[12] After about 20 years, the reliability of typical plants declines dramatically; figures 5-4 and 5-5 show typical increases in rate and duration of forced outages as a function of age.

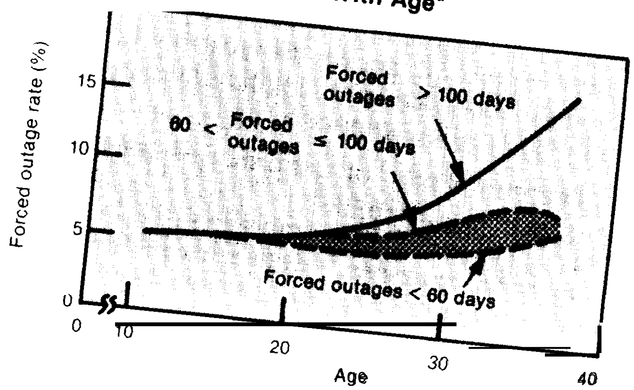
Utility concern about reliability, in particular, prompts the decision to invest in plant betterment projects because the cost of lost production during an outage may be very high. For example, if a utility's replacement power cost $0.04/kWh, a 1 percent improvement in the capacity factor of a 500 MW fossil unit will save the utility about $1.75 million a year. That savings must, of course, be balanced against the cost of achieving the capacity factor improvement; this trade-off is the central focus of plant betterment studies. The trade-off is illustrated in figure 5-6; the total "reliability cost" of operating a generating facility is the sum of the cost of lost production when outages occur and the plant betterment investment (or

[12] H. Stoll, General Electric Co., "The Economics of Power Plant Upgrading," unpublished paper, May 22, 1984.



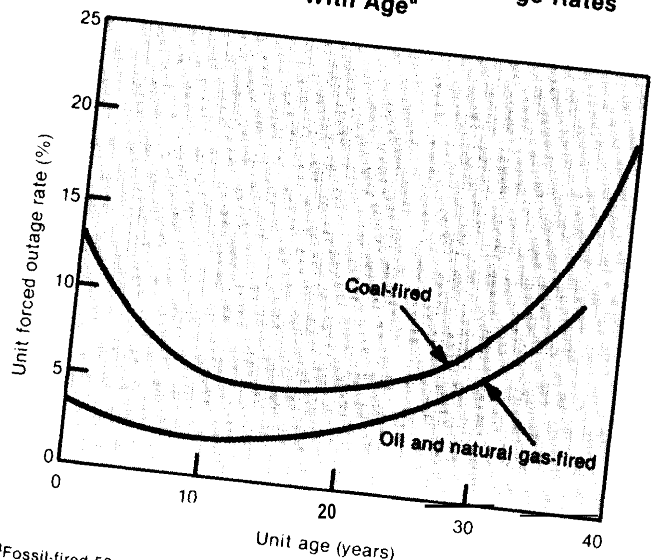
SOURCE: J. Studniarz, "Upgrading Fossil Steam Turbine Generators," General Electric Co., unpublished paper, 1984.

rend of Plant Forced Duration With Age[a]



[a]Powerplant forced outage rate ...
butions for ...

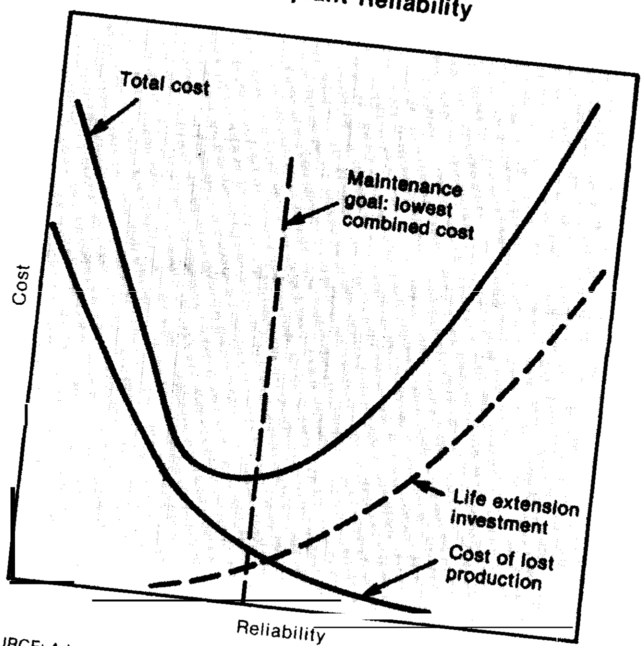
Figure 5-4.—Trends of Forced Outage Rates With Age[a]



[a]Fossil-fired 50 to 200 MW units.

SOURCE: H. G. Stoll, "The Economics of Power Plant Upgrading," paper presented at the Power Plant Life Extension, Renovation, and Uprating Workshop, American Public Power Association, Omaha, NB, May 22, 1984.

Figure 5-6.—Life Extension Cost v. Powerplant Reliability



SOURCE: Adapted from R. C. Rittenhouse, "Maintenance and Upgrading Inject New Life into Power Plants," *Power Engineering*, March 1984.

preventative maintenance allowance) charged to the plant to establish a given level of reliability. The cost of outage decreases as reliability increases and the plant betterment investment increases. The target of a plant betterment program is to minimize the total cost as shown in the figure.

The life extension and/or upgrading decision is complicated by the fact that, while a powerplant's forced outage rate increases with age, the aging characteristics of individual plant components as well as the cost of improving component reliability may vary widely.

Regulatory and Insurance Considerations

Regulation of Plant Betterment Projects

In addition to engineering feasibility, compliance with over 50 Federal and State regulations may be required in the course of considering a plant betterment program[13] These include Federal and State air quality programs, water quality and solid waste programs, environmental impact studies, Corps of Engineer rules, exemptions from the Powerplant and Industrial Fuel Use Act, and utility commission approval—see table 5-4.

Perhaps the most important regulatory considerations are the major Federal air quality regulations of NSPS, mentioned earlier, and the Prevention of Significant Deterioration (PSD) rules. Generally, Federal regulations apply to a plant betterment program that increases emissions by any amount or costs more than 50 percent of a new boiler. State Implementation Plans and other State air quality statutes will generally apply to all projects,

Of particular concern maybe the NSPS requirements which require that, if a fossil plant (>250 MMBtu/hr and constructed prior to 1971) is either "modified" or "reconstructed" as defined in table 5-4, the plant is subject to the 1978 NSPS provisions of stringent emissions limitations and percent sulfur removal. This would in most instances require pollution controls on a facility where few, if any, existed prior to the modification. The requirements are even more stringent for plants constructed between 1971 and 1978. It is important to note, however, that under the current regulations a great deal of plant betterment can be and is already being accomplished without these provisions being invoked.

A PSD permit is also required for any major modification to an existing plant; a special set of provisions defines and is applied *to* such modifications. Finally, if an upgraded existing facility increases emissions in a nonattainment area, pollution offsets would be required.

Table 5-4.—Powerplant Life Extension Projects: Regulatory Summary

Federal requirements:
NSPS (air):
- Standards apply if facility is:
  1. new:
     —replacement of boiler
  2. modified:
     —physical or operational change that results in increased emissions.
  3. reconstructed:
     —fixed capital costs exceed 50°/0 of the cost of a new steam generator.

PSD (air):
- Permit requirements apply to "major modification "—modification for which net emissions increase exceeds de minimis limits (permit may be issued by State).

NPDES (water):
- Permit required for point source discharges to navigable waterways. Modified sources require new or modified permit (permit may be issued by State).

State *requirements:*
Air:
- New or modified construction and operating permits required.
- Bubble policy may apply,

Water:
- New or modified construction and operating permits required.

Solid waste:
- New or modified construction and operating permits required.

Other requirements:
EIS:
- Not required unless major renovation subject to Federal licensing occurs.

Corps of Engineers:
- Nationwide permits for construction activity in navigable waters are available.

State PUC:
- Approval requried for modification of powerplant and recovery of costs through rate base.

SOURCE T Evans, "Regulatory Considerations of Life Extension Projects, ' Vlrglnla Electrlc Power Co , unpublished report, 1984

[13]D. Ward and A. Meko, "Regulatory Aspects of Power Plant Betterment, ' *Workshop Notebook: Fossil P/ant Life Extension* (Palo Alto, CA: Electric Power Research Institute, June 1984), EPRI RP- 1862-3.

Insurance Considerations

Of some concern in plant betterment projects is how insurance coverage might be affected. Insurance carriers generally consider the nature of risk exposure associated with a modified plant to be different from that of a comparable new facility. When setting insurance coverage premiums, these carriers now initiate very extensive evaluations (and annual reevaluations) of candidate equipment, particularly as more policies are written on a "comprehensive basis" where every piece of equipment is insured."[14] As the power industry moves toward including more plant betterment/life extension in its strategic planning, the implications on insurance coverage will become more important.

Industry Experience

To date, most life extension activity has been confined to planning, but a number of projects have been announced.

Potomac Electric Power Co. (PEPCO) has announced a $79 million project on its Potomac River Station, the oldest in the PEPCO system with two 92 MW and three 110 MW units built between 1949 and 1957. The work will be performed over the next 10 years during each unit's annual 2-month scheduled outage.[15]

Pennsylvania Power & Light Co. (PP&L) is reviewing all fossil and hydroelectric capacity built between 1949 and 1977, comprising about 4,500 MW. The utility has initiated a formal technical inspection program and has identified $173 million worth of individual recommendations.[16] The most important of these is a $20 million project to extend the life of Brunner Island Station (343 MW Unit 1) to 2010.

Wisconsin Power & Light (WEPCO) has commissioned detailed life extension studies at its Port Washington Station (five 80 MW units commissioned between 1935 and 1950) and its Oak Creek Station (eight units totaling 1,670 MW commissioned between 1953 and 1967).

Cincinnati Gas & Electric Co. (CG&E) has decided to commit $2.8 million to its 94 MW Beckjord Unit 1 turbine (currently 29 years old) to permit continued operation through 2013.

Colorado Ute Electric Association, Inc., is completing a major life extension project that includes an atmospheric fluidized-bed (AFBC) boiler retrofit to increase the plant capacity at their Nucla facility from 36 to 110 MW. The project objectives include a 15-percent increase in overall heat rate, a 30-percent reduction in fuel costs, and reduced emissions. The estimated project cost is $840/kW.[17] As mentioned in chapter 4, retrofit applications are likely to be an important entry point to the utility market for AFBC technology.

Duke Power Co., Florida Power Corp., and the Tennessee Valley Authority have all initiated extended cold shutdown programs for a number of units which they plan to reactivate in the early 1990s.

Summary and Conclusions

Plant betterment and life extension of aging fossil units are emerging as economical alternatives to new capacity construction to the extent this can be done, for many utilities. As the industry gains experience with these options, the costs of such activities will become less uncertain. As the U.S. powerplant inventory matures in the late 1990s, plant betterment and life extension are likely to become major components in the portfolio of strategic options of most generating electric utilities.

[14]F. Mansfield, "A Risk Taker Looks at Utility Equipment Plant Betterment," *Workshop Notebook: Fossil Plant Life Extension* (Palo Alto, CA: Electric Power Research Institute, June 1984), EPRI RP-1862-3.

[15]R. Smock, "Operating Unit Heat Rates Can Be Cut, Says EPRI; New Units Can Be 10 Percent More Efficient," op. cit., 1984.

[16]T. Yezerski, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co.," op. cit., 1984.

[17]T. Moore, "Achieving the Promise of FBC," *EPRI Journal*, January/February 1985, pp. 6-15.

CONVENTIONAL GENERATING OPTIONS

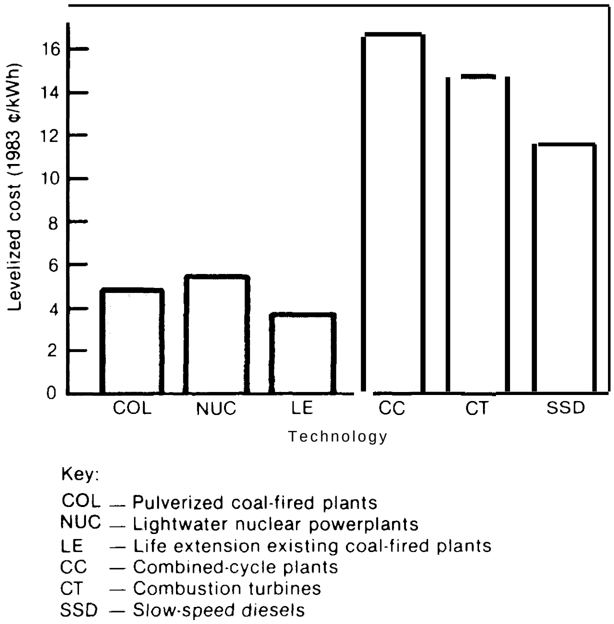
in order to be deployed in significant numbers, the developing technologies addressed in this report must compete successfully with existing electric utility generating options. The five major conventional power generation technology types that will most likely be available to electric utilities in the 1990s are: pulverized coal-fired plants, combined-cycle plants, combustion turbines, slow-speed diesels, and light water nuclear powerplants.

This section briefly presents the benchmark cost and performance estimates for these five technologies as well as for life extension of existing coal-fired plants. Cross-technology comparison of these technologies with the developing technologies is contained in chapter 8.

Table 5-5 contains the benchmark set of cost and performance estimates for the five conventional technologies. All of the listed technologies, except one—combustion turbines—are capable of base load operation. Three of these technologies, pulverized coal-fired, combined-cycle, and slow-speed diesel, are also capable of intermediate-load operation. One major difference among the conventional alternatives is plant size. Although there is increasing interest in small, modular plants (see chapter 3), the technologies listed in table 5-5 are generally large, central station powerplants. Slow-speed diesels and combustion turbines represent the smaller sized central station technologies.

The levelized cost model used in chapter 8 was used with the cost and performance estimates shown in table 5-5 to derive most likely electric utility costs. These levelized costs are presented in figure 5-7. This figure also includes a levelized cost estimate for existing coal powerplant betterment. The plant costs and the capacity and effi-

Figure 5-7.—Conventional Technology Costs, Utility Ownership—West



SOURCE: Office of Technology Assessment.

ciency upgrades discussed earlier were applied to the generic coal plant listed in table 5-5 to derive an expected cost for coal plant betterment. According to this figure, the lowest cost conventional alternative is life extension and plant betterment of existing coal units. The next lowest cost conventional alternative is pulverized coal plants, followed by light water nuclear plants.

The cost and performance estimates for the conventional technologies discussed in this section represent the present technologies expected to be available in the 1990s. Additional enhancements to these technologies or different design configurations may occur prior to 1990 which could dramatically change these expected costs.

Table 5.5.—Cost and Performance Summaries

	Technologies					
Reference swstem	Pulverized coal-fired	Combined-cycle	Combustion turbine	Slow-speed diesel	Municipal solid waste	Nuclear
General:						
Reference year	1990	1990	1990	1990	1990	1990
Reference-plant size	500 MWe	600 MWe	150 MWe	40 MWe	60MWe	1,000 MWe
Lead-time	6-8 years	3-4 years	2-3 years	2 years	5-7 years	11 years
Land required	640 acres	5-10 acres	2-5 acres	10-15 acres	20 acres	1,000 acres
Water required	5.94 million galiday	2.9 million gal/day	Negligible	Negligible	0.85 million gal/day	10 million gal/day
Performance parameters:						
Operating availability	75%	90%	90%	95%	850/o	68%
Duty cycle	Intermediate/ base	Intermediate/ base	Peaking	Intermediate/ base	Base	Base
Capacity factor.	25-75%	25-75%	5-15%	25-75%	65-75%	65-75%
Plant lifetime	30 years	30 years	20 years	30 years	20 years	30 years
Plant efficiency	34%	40%	25.0%	39%	20.7%	31.9%
costs:						
Capital costs	$1,080/kWe	$650/kWe	$350/kWe	$1,200/kWe	$2,500/kWe	$1,700-$2,100/ kWe
O&M costs	9.5 mills/ kWh	2.4-4.2 mills/ kWh	4-4.7 mills/ kWh	5.1-8.2 mills/ kWh	19 mills/ kWh	3-3.3 mills/ kWh
Fuel costs	17 mills/ kWh	30.4 mills/ kWh	48.6 mills/ kWh	42 mills/ kWh	46.9 mills/ kWh	9.1 mills/ kWh

SOURCE: Office of Technology Assessment; complied from Gibbs & Hill, Inc., "Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s," contractor report to OTA, Sept. 13, 1984; and *Technical Assessment Guide* (Palo Alto, CA: Electric Power Research Institute, 1982), EPRI P-2410-SR.

LOAD MANAGEMENT

Introduction

The term load management refers to manipulation of customer demand by economic and/or technical means. It involves a combination of economic arrangements and technology typically directed towards one of the following objectives:

1. **Encouraging demand during off-peak periods:** During the valleys of a load curve, a large portion of generating equipment is idle. Utilities benefit when that capacity is more heavily used. This typically is achieved by either shifting use to those periods from peak-demand periods (load shifting) or by encouraging additional use during off-peak periods (valley filling).
2. **Inhibiting demand during peak periods:** It may also be desirable to reduce peak-period demand. When electricity is purchased from other utilities, costs per kilowatt-hour during these periods are high. Or, to meet peak-period demand, a utility may have to use generators which are more costly to operate because they are older and less efficient or they burn more expensive fuel. In addition, if growth in peak-period demand requires the utility to invest in new capacity, load management may reduce the rate at which such expenditures must be made.

In the context of this study, the most important benefit "of load management lies in the second objective which if realized allows utilities to defer additional peak-load generating capacity. In addition, by reducing the share of the load served during the peak period, load management permits a higher proportion of demand to be served by lower cost electricity. other advantages are also becoming evident as utilities gain more experience with load management, and as sophisticated models are developed which permit better assessment of load management.[18] For ex-

[18] For example, see: 1) John L. Levett & Dorothy A. Conant, "Load Management for Transmission and Distribution Deferral," *Public Utilities Fortnightly*, vol. 115, No. 8, Apr. 18, 1985, pp. 34-39; 2) Associated Power Analysts, Inc., *Study of Effect of Load Management on Generating-System Reliability* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3575.

ample, load management may reduce future demand uncertainty. And some utilities have found it to be an effective means of improving the efficiency of power system operation by allowing increased flexibility in the hour-by-hour allocation of system resources.[19]

Load management is only one of many closely related options available to utilities in managing demand. Other demand management alternatives include encouraging conversions to electric power through new applications, and more efficient use such as home insu lation and electronic motor controls. In addition, demand management is also carried out indirectly to the degree that customers are encouraged to generate their own power. These other demand management options may be pursued independently of load management, or may be implemented as part of an integrated program with load management. Depending on the nature of the demand management strategy, the utility's daily load curve can be modified as shown in figure 5-8.

Within load management falls a very wide range of strategies, technologies, and economic arrangements. These typically center around some combination of: 1) load management incentives, 2) advanced meters, and 3) load control equipment, While many other elements may be present in a load management program, these appear to be of pivotal importance. Although incentives will be touched upon below, the emphasis will be placed on the technologies themselves: specifically advanced meters and load control equipment.

With respect to the number of customers, the residential sector is by far the most important i n load management. But the fact that the sector consists of a large number of relatively small consumers makes load management quite difficult to assess and implement. In part, because of this, only a small fraction of the major electric appliances in this sector have load management controls (see table 5-6). Nevertheless, utilities are increasingly interested in residential load management, both because the sector uses a large quantity of electricity (in 1984 it accounted for 34 percent of all electricity used) and because it is the largest contributor to the daily fluctuations in demand (see figure 5-9).

In the industrial and commercial sectors, while only a relatively small number of loads have been managed, the contribution has been significant. These sectors contain major loads amenable to load management, and, compared to the residential sector, fewer customers with larger demands per customer. Hence, load management is already practiced more widely in these sectors. Considerable opportunities remain, however, and industrial and commercial customers likely will continue to account for a major portion of load management during this century.

Current evidence suggests that load management will provide, in many cases, an economic alternative to new generating capacity in the 1990s, It may be a particularly attractive utility investment when it is part of an integrated system designed not only to manage loads but also to serve other utility or customer needs.

Some of the potential for load management can be met by using existing technologies at current costs and performance levels; but considerably greater application will require the introduction of technologies which offer a combination of cost, performance, and risk superior to current technology. Furthermore, institutional arrangements must be developed within which load management can be more easily deployed. Finally, the costs, benefits, and uncertainties of load management options must be better understood and integrated into the thinking of utilities and of others upon whose decisions affect load management deployment.

Major Supply/Demand Variables Relating to Load Management

Key End-Use Sectors and Applications

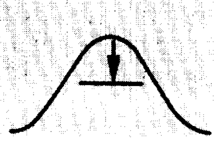
Central to load management in the 1990s will be the electricity demand patterns which develop in the united States. What sectors will be most important and how will they use electricity? These patterns determine the magnitude of the load at any time, and the shape of the load curve, They

[19] B. F. Hastings, "Cost and Performance of Load Management Tech nologies, " comments presented at OTA Load Management Workshop, Washington, DC, Aug. 15, 1984.

Figure 5.8.— Load Shape Objectives

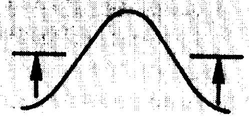
PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.

PEAK CLIPPING



VALLEY FILLING is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.

VALLEY FILLING

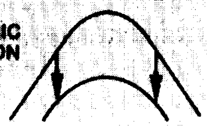


LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.

LOAD SHIFTING

STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end-use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.

STRATEGIC CONSERVATION

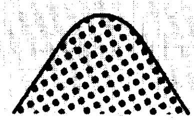


STRATEGIC LOAD GROWTH is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.

STRATEGIC LOAD GROWTH

FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible—if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.

FLEXIBLE LOAD SHAPE



"Adapted from Clark W, Gellings, Highlights of a speech presented to the 1982 Executive Symposium of EEI Customer Service and Marketing Personnel.

SOURCE Battelle-Columbus Division & Synergic Resources Corp., *Demand-Side* Management, *Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1964), EPRI EA/EM-3597

Table 5-6.—Use of Major Electricity-Using Appliances in U.S. Residences, 1982

Household characteristics	Total	Census region			
		Northeast	North Central	South	West
Total households (millions)	83.8	18.0	21.3	28.1	16.5
Millions of households where electricity is main:					
Space heating (SH) fuel	13.4	1.3	2.1	6.8	3.1
Water heating (WH) fuel	26.6	3.7	5.5	13.2	4.2
Millions of households where electricity is secondary:					
SH fuel	10.5	1.9	2.1	4.2	2.3
Millions of households with air-conditioning (A/C)	48.7	9.4	12.3	21.3	5.7
Millions of households with combinations of electric:					
SH + WH with A/C	9.0	0.8	1.6	5.4	1.2
SH + WH without A/C	2.9	0.4	0.3	0.8	1.4
Minimum number of controllable points (millions)[a]	88.7	14.4	19.9	41.3	13.0
Points controlled in 1983 (millions)[b]	1.2	0.02	0.44	0.7	0.13
Total 1983 sales of electricity to residential sector (gigawatt hours)	750,948	111,619	184,211	317,458	137,661

[a]This merely is the sum of (number of households with electric space heating as primary source of heating) + (number of households with electric water heaters) + (number of households with air-conditioners).

[b]The figures for the number of points controlled are derived from a 1983 survey of 298 utilities. The results were not broken down by census regions but by EPRI regions; since the EPRI regions do not coincide exactly with the census regions, the figures are approximate. The points itemized here only include water heaters, air-conditioners, and space heaters. These figures include 0.03 million commercial points; because this figure is so small compared to residential points, it does not significantly affect the magnitudes of the numbers.

SOURCES: Office of Technology Assessment; based on data presented in U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Housing Characteristics 1982* (Washington, DC: U.S. Government Printing Office, August 1984), DOE/EIA-031(82); U.S. DOE, EIA, *Electric Power Annual 1983* (Washington, DC: U.S. Government Printina Office. Julv 1984). DOE/EIA-0348(83); and Svneraic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Ins;ltute May I'9&l), EPRI EM.3529

also strongly influence the selection of load management strategies. For example, managing industrial use of electricity for process heat will be quite different than that of managing residential electricity demand for air-conditioning.

Usage patterns will depend on many interrelated variables; precise predictions of future consumption are impossible.[20] Nevertheless, many useful generalizations can be made by looking at the conditions which have characterized the past.

In the residential sector, the single most important application of electric power is air-conditioning, which in 1984 accounted for about 14 percent of delivered residential electricity.[21] Somewhat less important but still sizable quantities of electricity were used for water heating and space heating. These three applications accounted for over a third of residential electricity consumption in 1983. These appliances are particularly important in load management efforts because they typically are major contributors to fluctuations in overall demand for electric power (see figure 5-9).

In the commercial sector, lighting and air-conditioning are the most important applications for electric power, each accounting for roughly 40 percent of electricity use. Much of the rest is used in used in water and space heating. The use of electric power for air-conditioning and space heating in the commercial sector is especially important. They accounted for 12 percent of national electricity use (1 984) and contribute significantly to daily fluctuations in demand.

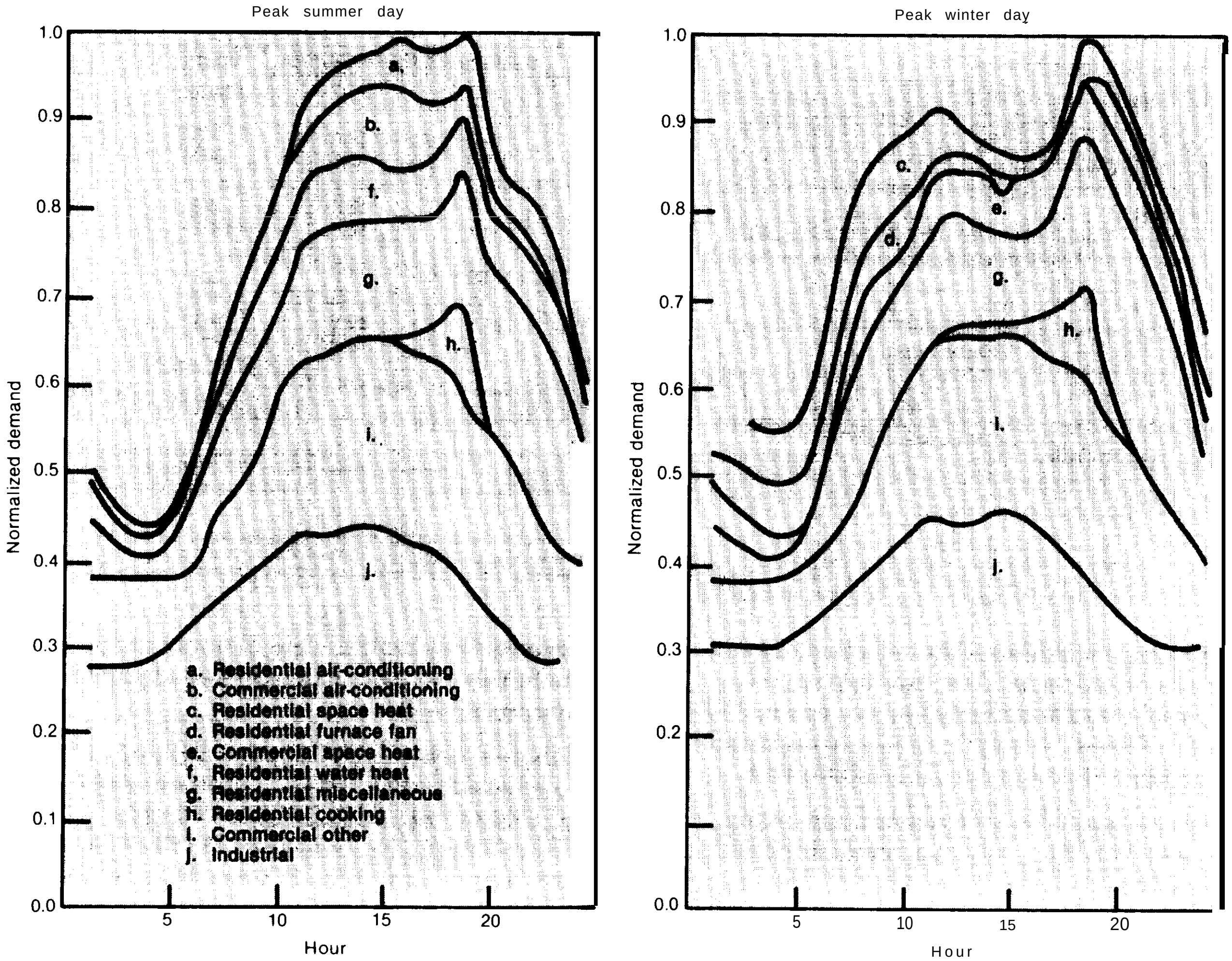
In industry, the largest fraction of electric power—over 50 percent in 1984—is used in machine drives. Electrolysis accounted for about 13 percent industrial electricity use; slightly less was used in generating process heat. Most of the balance went for for space heating and lighting. While industry uses a large amount of the electrical energy, its cyclical variations tend to be less extreme than those in the commercial and residential sectors.

As table 5-7 suggests, the individual applications which account for the largest portion of electricity use is found in the industrial sector, followed by the commercial sector and then the

[20]For example, see: Rene H. Males, "Load Management—The Strategic Opportunity," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 3-1 through 3-8.

[21]End-use energy consumption excludes the energy used to generate and transmit electricity to the end-use sectors, and accounts for only the energy used by the consumer.

Figure 5-9.—illustration of Customer Class Load Profiles—North Central Census Region in the 1970s



SOURCES: Decision Focus, Inc., *Integrated Analysis of Load Shapes and Energy Storage*, March 1979; and Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

residential sector. The importance of individual sectors varies widely from region to region and from utility to utility, as does the importance of specific applications within those sectors.

While there will be some changes in the relative importance of some electricity end uses over the coming years, the 1983 patterns (table 5-7) provide a general indication of which loads will be most important in shaping the demand for utility power—and in load management efforts—in the 1990s. The success of load management will depend on the ability of the utilities to influence customer demand in those applications.

Other Variables

In addition to the characteristics of a utility's customers, other variables are important indicators of the potential for load management. Generally speaking, load management tends to be favored where load factors[22] are low and where peaking capacity is expensive and base load capacity is cheap. Also, load management is favored where utilities purchase a large portion of their

[22] Load factor is the ratio of the average load supplied during a designated period (e.g., hourly, daily, monthly, or annual) to the peak or maximum load occurring during the same period.

Table 5-7.—Major Uses of Purchased Electricity in the United States, 1983

Sector	Application	Billions of kWh (estimated)	Percent of total U.S. purchased electricity
Industrial	Machine drive . .	539	25
Commercial	Air-conditioning	231	11
Commercial	Light	220	10
Residential	Air-conditioning	111	5
Industrial	Electrolysis	103	5
Residential	Water heating . .	97	4
Industrial	Process heat . . .	97	4
Residential	Space heat.	70	3
Commercial	Water heating . .	59	3
Industrial	Light	47	2
Commercial	Space heat.	29	1
Total		1,603	74

SOURCES: **Industrial:** The breakdown for industrial electricity use was obtained from table 1-10 in Pradeep C. Gupta and Ahmad Faruqui, "EPRI Perspective on Industrial Electricity Use," *Proceedings: Forecasting the Impact of Industrial Structural Change on U.S. Electricity Demand*, Battelle Memorial Institute, Columbus Laboratories (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3816, pp. 1-1 through 1-17. The percentage breakdown provided in the article was for 1980. It was assumed in the above calculations that the breakdown in 1980 was the same as that in1983. These percentages were applied to the Department of Energy estimates of industrial purchases of electrical power, see U.S. Department of Energy, Energy Information Administration, *Energy Conservation Indicators 1983 Annual Report* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0441, table 33.
Commercial: The breakdown for commercial energy consumption was obtained from Oak Ridge National Laboratory's *A User's Guide to the ORNL Commercial End Use Model* (Oak Ridge, TN: ORNL 1980). It was assumed in the above calculations that the breakdown provided by ORNL was the same as that which characterized the commercial sector in 1983. These percentages were applied to the DOE estimates of industrial purchases of electrical power, as provided in table 24 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.
Residential: The breakdown for residential energy consumption was obtained from an estimate provided from U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1984* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0383 (84), table A6. The breakdown was applied to the 1983 estimate of residential electricity purchases, as provided in table 11 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.

electric power rather than generating it themselves. These characteristics, alone or in combination, may encourage load management. Though these features vary from one utility to the next, some regional generalizations can be made. (See the section on load management in chapter 7.)

Current Status of Load Management Efforts

Because of the large variety of forms which load management may take, it is very difficu k to accurately determine the extent to which it is being exercised by utilities. There are, however, two key indicators of load management activity which have been examined in detail in surveys by the Electric Power Research Institute (EPRI). First is the implementation by utilities of innovative rates designed to modify customer electricity demand patterns. Second are activities by the electric utilities relating to direct load control.

Innovative Rates

The Electric Power Research Institute in 1983 sponsored a survey of electric utilities to gather information on innovative rates in the utility industry. EPRI found that at least half of the investor-owned utilities in the United States had implemented or proposed innovative rates; and about 6 percent of publicly owned utilities had done so.[23] The most commonly applied rates were time-of-use rates, rates which are linked to the specific time at which the power is needed. Figures 5-10 and 5-11 illustrate how a time-of-use rate can affect electricity demand.

About 20 million electricity customers served by utilities which responded to the EPRI survey are affected by innovative rates. That is about 21 percent of all the utility customers in the United States.[24] Most of the customers under the innovative rates were in the residential sector, though

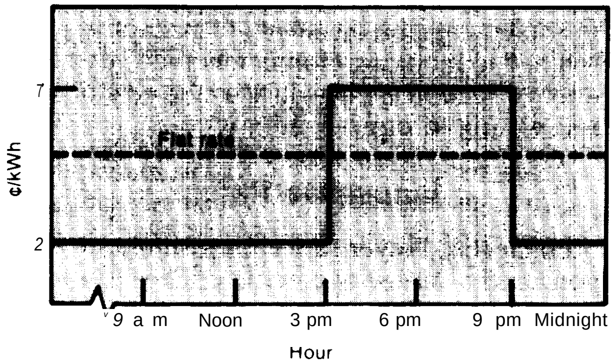
[23] The estimates are based on information provided by the Electric Power Research Institute (Ebasco Business Consulting Co., *Innovative Rate Design Survey* (Palo Alto, CA: Electric Power Research Institute, 1985), EPRI EA-3830).

In the responses to a checklist sent to the members of the American Public Power Association and the National Rural Electric Cooperative Association, approximately 175 members reported innovative-rate design activity. Since there is a total of about 3,069 publicly owned utilities in the United States, this amounts to about 6 percent of all publicly owned utilities. This 175-member estimate should be treated as a low figure, as it does not include utilities which were not members of the two associations; nor does it include utilities who did not respond to the checklist.

In the case of the investor-owned utilities, EPRI found that 106 utilities have either proposed and/or implemented innovative rates. Since there are about 204 investor-owned utilities in the United States, this amounts to about 52 percent of those utilities. As with the publicly owned utilities, this should be treated as a low figure. The number is based on only 123 survey responses–about 60 percent of investor-owned utilities,

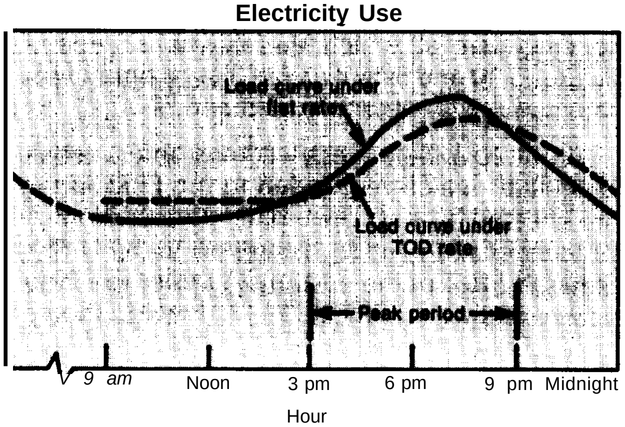
[24] This is based on an estimate made by the Edison Electric Institute that there was a total of 97 million ultimate customers of the entire electric utility industry as of Dec. 31, 1983 (Edison Electric Institute, *Statistic/ Yearbook of the Electric Utility Industry* (Washington, DC: EEI, 1984), p. 58),

Figure 5-10.—An Example of Time. of-Day Rate



SOURCE: Jan Paul Acton, et al., *Time-of-Day Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., 1983), R-3086-HF.

Figure 5-11 .—Time-of -Day Rates Shift Patterns of Electricity Use



SOURCE: Jan Paul Acton, et al., *Time-of-Day Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., 1983), R-3086-HF.

there were a substantial number of industrial and commercial customers as well.[25]

Unfortunately, very little is known about the precise impact of these rates on electricity supply and demand nationwide. To the extent that assessments have been made, they typically have been utility-specific and limited in scope. The available evidence indicates that utilities have. in many instances, effectively and economically managed loads by implementing carefully structured rate programs.[26] But this has not always been the case. Rates in some cases have been developed and implemented which have had little or no impact on demand patterns. This is an indication of the difficulty in understanding customer demand patterns and in designing and implementing rates for load management.

Load Control

Utilities have controlled loads in the United States for about half a century. The earliest efforts in the United States, in the 1930s, involved the installation by utilities of timers on appliances[27] to inhibit appliance operation during preselected periods. But only within the last decade have utilities seriously considered load control as a potentially attractive investment.

The 1983 EPRI survey also sought to assess utility activities in load control. *a While, as mentioned earlier, numerous objectives could be served by load control, the survey found that it has been viewed primarily as a means of reducing wholesale power costs and has been most vigorously pursued by utilities which purchase much of their power from other utilities. By far the most active in load control are rural distribution cooperatives and municipal utilities. Together they accounted for one-third of the loads controlled in 1983.

As is the case with innovative rates, the largest number of customers subject to load control falls within the residential sector (see table 5-8). Table 5-6 summarizes the load management activity which was underway among U.S. residences, *g and provides a rough idea of the number of points which are available for control. The table suggests that only a very small portion-perhaps only a few percent—of the residential appliances are subject to load control.

Given the large potential in the South (see table 5-6), it is not surprising that in 1983, roughly

[25] According to a study by the Rand Corp. (Jan Paul Acton, et al., Time-of-Day *Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., November 1983), more than 12,000 commercial and industrial enterprises fell under time-of-day rates (the major form of time-of-use rates) by the early 1980s.

[26] Ibid.

[27] Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

[28] I bid.

[29] The table includes only space heating, water heating, and air-conditioning. It does not include pool pumps and other controlled points.

Table 5-8.— Load Control: Appliances and Sectors Controlled in 1983 Under Utility ”Sponsored Load Control Programs

Appliance/sector	Number of points controlled
Electric water heaters:	
All sectors	648,437
Residential	643,910
Commercial	4,527
Air-conditioners:	
All sectors	515,252
Residential	491,675
Commercial	23,577
Irrigation pumps:	
All sectors	14,261
Space heating systems:	
All sectors	50,238
Residential	48,546
Commercial	1,692
Swimming pool pumps:	
Residential	258,993
Miscellaneous:	
All sectors	13,710
Residential	13,088
Commercial	34
Industrial	588
All appliances:	
All sectors	1,500,891 (100%)
Residential	1,456,212 (97%)
Commercial	29,830 (2%)
Industrial	588 (negligible)
Agricultural	14,260 (1%)

SOURCE: Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

58 percent of the load control points[30] nationwide were located there; 37 percent were i n the North Central region, followed by the West, with 11 percent. The Northeast, though it appears to have somewhat more controllable points than the West, accounts for less than 2 percent of the points currently controlled.

The nationwide impact of the load control measures in place in 1983 has not been precisely determined. It can be very roughly estimated, however. The average peak load reductional reported in the 1983 EPRI survey of 298 utilities was 1 kW for each controlled residential air-conditioner and 0.6 (summer) to 0.9 (winter) kW for each controlled residential water heater. These averages should be interpreted with caution; the results vary widely from one utility to the next, Since there were 643,910 residential water heaters and 491,695 residential air-conditioners controlled in 1983, the peak load reduction might have been roughly 880 MWe in the summer (if all the water heaters were controlled during the summer) and 580 MWe (if all the water heaters were controlled during the winter).

While positive results were observed for many load control projects, utilities often were not wholly satisfied with the performance of the load management technologies they used. In particular, equipment has been relatively unreliable. The problems resulted from a combination of factors. To some extent these resulted from inferior products, or other supplier problems; but many also resulted from the manner in which the technology was used. Most of these problems have been alleviated over time and appear to be the kind of passing difficulties which are to be expected with the application of new configurations of technologies to relatively complex circumstances .32

Potential Peak Load Reductions From Load Management

The potential peak load reduction from load management in the 1990s depends on many factors. At the most basic level, the peak load reduction from any load management program depends on: 1) the total numbers of customers and electricity using appliances, 2) the nature of the appliances and the manner in which they are

[30]A "point" in this discussion refers to the point at which the specific load is controlled. For example, if a home has a single air-conditioner with a load control device, that air-conditioner constitutes a point. If the home had several such air-conditioners, each with its own load control device, each would be considered a point. Consequently, any one customer may account for several points, depending on the number of independently controlled appliances on the premises.

[31]The peak load reduction is the magnitude of the additional power which would have been required to meet demand had the appliance not been controlled.

[32]Analysis and Control of Energy Systems, Inc., *Residential Load Management Technology Review* (Palo Alto, CA: Electric Power Research Institute, 1985), EPRI EM-3861.

used, **3)** the extent to which customers participate in the load management effort, and 4) the peak load reduction achieved for each appliance. These variables in turn depend on many other conditions, some of which vary greatly from utility to utility, and even within the territory of a utility. Only now are methods being developed and refined for predicting the results of load management programs.[33]

An accurate, reliable, and detailed estimate of the nationwide potential of load management requires an effort beyond the scope of this report. However, strong evidence suggests that there are many opportunities for increasing the number of customers and points under load management programs, It is apparent that though innovative electricity rates are becoming more common in the United States, most utility customers do not yet fall under such rates. Likewise, as table 5-6 suggests, only a tiny fraction of customer loads are controlled through load control programs,

Evidence suggests that customers in many–*though not* a//–instances would be favorably disposed towards both special rates and load control.[34] The precise customer response depends not only on the character of the customers but also the nature of the load management effort.[35] Where rates and load control are implemented, significant peak load reductions may occur. Considerable variation in customer attitudes toward load management and in the impacts of load management likely will characterize different utilities across the country.

The management of a relatively small number of large individual loads, such as those commonly found in the industrial and commercial sector, typically will present fewer problems and impose lower costs than management of a large number of small loads. A rate structure which encourages load management may be applied readily and effectively to large users. The deployment by utilities of the technologies required to implement some of these rates among such users is generally inexpensive relative to the potential gains for the utility. Moreover, once the economic incentive is offered, the users themselves (industrial and commercial) frequently are capable of deploying technologies which are effective in changing their demand in accordance with the utility's incentives and their own economic interests.[36]

Where a large number of small users are involved such as in the residential sector, the difficulties are more limiting. In 1983, there were over eight times as many residential customers in the United States than commercial and industrial customers. And the average residential customer used less than 9 MWh/year, compared with 1,560 MWh/year by the average industrial customer and 53 MWh/year by the average commercial customer.

Consequently, special rates tend to be less readily and profitably applied to the residential sector, and the cost-benefit ratio for the utility for each load, managed is likely to be larger. In addition, the cost and difficulty of installing, maintaining and operating the equipment, required as an adjunct to such rates may be considered excessive by utilities. Compounding the problems is the utilities' uncertainty about future residential electricity use, and the manner in which it would change under alternative load management programs.

[33]See the following: 1) Robert T. Howard, "Estimating Customer Response to Time-of-Use Rates, " *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRIEA-3464, pp. 16-3 through 16-4. 2) T.D. Boyce, "Estimating Customer Response to Direct Load Management and Thermal Energy Storage Programs, " *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRIEA-3464, pp. 16-7 through 16-10.

[34]See:1) Thomas A. Heberlein & Associates, *Customer Acceptance of Direct Load Controls: Residential Water Heating and Air Conditioning* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRIEA-2151; 2) Thomas A. Heberlein, "Customer Attitudes and Acceptance of Load Management, " *Workshop Proceedings: P/arming and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRIEA-3464, pp. 4-1 through 4-21; and 3) Ebasco Business Consulting Co., *Innovative Rate Design Survey,* op. cit., 1985.

[35]See Tom D. Stickels, San Diego Gas & Electric, "Analyzing Customer Acceptance of Load Management Programs, " *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRIEA-3464, pp. 16-1 through 16-3.

[36]For an assessment of the possible costs and benefits of load management using incentive rates for seven major industries, see: Chem Systems, Inc., *The Potential for Load Management in Selected Industries* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EA-1821-SY.

At present about 1.5 million points are controlled,[37] which is only a small fraction of the number of residential loads that could be controlled (probably less than 1 percent). A much larger potential exists in every region of the country, particularly in the South where residential electricity demand is high and there are a large number of all-electric homes. A recent survey of the stated intentions of utilities indicates that if currently planned load control programs are implemented, at least 5 million new points may be controlled by 1990.[38] Another report suggests that 8 million points will be controlled by 1990 and 20 million points by 1995,[39 40]

The potential magnitude of the impact of load control is difficult to gauge. Evidence from current load management efforts indicates that the impact could be quite sizable. If, for example, one air-conditioner in each of 5 million homes were controlled, and if an average peak load reduction of 1 kWe were obtained, a peak load reduction of about 5,000 MWe would result. Note that nearly 50 million homes have air-conditioning and that many of these have more than one air-conditioner. Also residential air-conditioning represents only one of many loads which could be controlled.

Overall, the potential for load management is such that it is an important strategic option in the U.S. electricity supply outlook in the 1990s. Whether utilities fulfill this potential will depend on the cost, performance, and risk of load management technologies and on the ability of the utilities to manage those technologies and develop innovative rates.

[37]Synergic Resources Corp., 7983 *Survey of Utility End-Use Projects*, op. cit., 1984.

[38]Ibid.

[39]The Laird Durham Co., *The United States Market for Residential Load Control Equipment, 1983-7995* (San Francisco, CA: Laird Durham Co., 1984).

[40]A recent Frost & Sullivan report suggests that 7 million points will be controlled by 1992 (Frost & Sullivan, *Electric Utility Customer Side Load Management Market* (New York: Frost & Sullivan, 1984), as reported in "Load Management Systems Will Control Seven Million by 1992, " *Electric Light& Power, vol. 62, No. 8,* August 1984, p. 47).

Technologies for Load Management

Given the magnitude of demand in the residential sector, its importance in contributing to the fluctuations in demand for electric power, and the characteristics of individual residential customers, it is not surprising that the technology-related problems of current utility efforts to manage loads center on small users. This will also be the emphasis here. Many of the technologies, issues, and problems in the residential sector, however, also are applicable to the other sectors.

Two principal groups of technologies are required in load management:

1. **Advanced meters:** Meters measure electricity use; recorders, often integrated into a single device with the meter, record this information for later use. The data help in developing load management strategies, in implementing them, and in assessing their results. They also facilitate the application of rates which encourage the deployment of customer-owned and operated load management technologies.
2. **Load control systems:** In order to control loads, utilities may need to be capable of communicating with the customer. *Communications systems* provide this link, allowing the transmission from the utility to the customer, and perhaps vice versa. Required for successful load control systems are *decision-logic technologies* which interpret information and automatically generate decisions necessary for effective load management,

Advanced Meters[41]

The predominant residential electric meter and recorder used in the United States is the single-phase (see chapter 6 for definition of single phase and other relevant terms) electromechanical watt-hour meter which requires periodic reading by an individual on location. A variety of solid-state meters, "hybrid meters"[42] and other ancillary

[41]Strictly speaking, a meter only measures electrical power or energy. Here however, the term is used loosely to include devices which not only perform the measuring function, but also record and perhaps even manipulate the data.

[42]A hybrid meter is one which couples the common meter's rotating sensing-element to a solid-state microprocessor.

equipment (including communications technologies) are available and being developed to assist in meeting the rising information needs of load management. Among the equipment being developed is hardware which can be retrofitted to existing equipment to enhance the capabilities of common meters.

Advanced meters can perform many more tasks. For example, they may provide the customer not only with data on current and past use, but also information on present costs and other matters; that additional information could be wholly or partly generated by pre-programmed equipment on site or transmitted from a remote location. Where time-of-use rates were being applied as part of a load management program, the information is essential for the consumer. Alternatively, the meter could provide direct and automatic input to the load control system. For example, a "demand-subscription service" meter will automatically trigger a sequence of events designed to curtail load when the meter indicates that demand has exceeded a specified level.

Currently available advanced meters, however, often are expensive, unreliable, and short-lived, relative to conventional meters. Considerable evidence indicates that the technical problems could be resolved relatively easily, but developers appear reluctant to do so without assurances that a major market exists. Similarly, costs can only be reduced sufficiently through mass production and deployment.

Another consideration is that the conventional meter is a long-established fixture in U.S. utility operations. It performs the task expected of it without imposing inordinately large operating and maintenance costs. While new meter designs could in the long run be superior, they would require changes, People would have to be trained. Some workers might no longer be needed; others, with different skills, would be required. New maintenance facilities likely would be needed, and operating procedures would have to be modified to accommodate the new technology.[43]

[43]" How to Get Meter Readers to Use Computers, " *E/ectrica/ World*, vol. 198, No. 10, October 1984, pp. 26-28.

While problems remain, no major unresolvable technological barriers impede the deployment of advanced meters. Rather, the problems appear to be related to the development of an early market among utilities and to the need for changes in utility practices. The evidence indicates that unless concerted efforts are made to eliminate these impediments by stimulating demand, the deployment of advanced meters will be a slow process. Their conventional competitors likely will predominate well past the close of this century, though their position will be eroded slowly by the newer technologies.

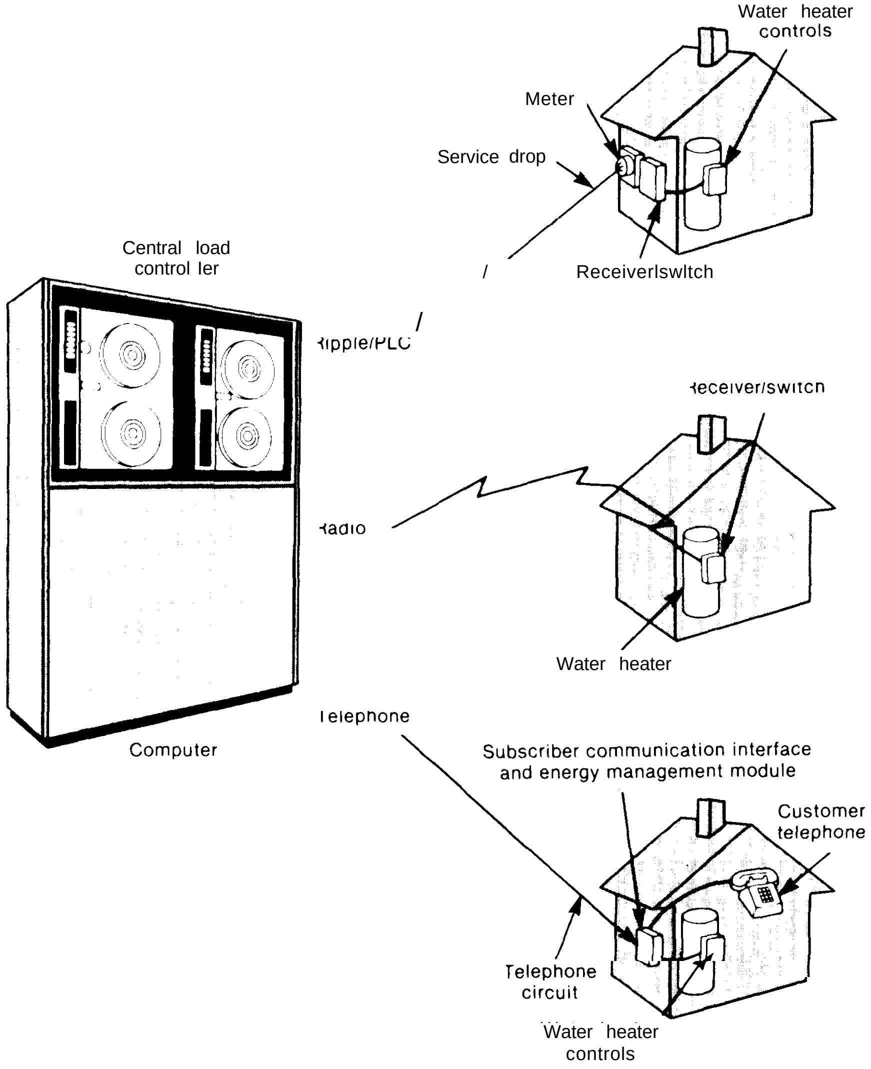
Load Control Systems

Load control systems vary in the extent to which control is concentrated on either side of the meter (customer or utility); in the extent to which information from the customer side-of-the-meter is used and in the nature of that information; and in the degree of automation on the customer side-of-the-meter. Some require relatively active customer participation and a low level of automation. For example, the utility may simply call up the customer and ask that his load be reduced as much as possible; the customer could respond by turning various appliances off, basing his actions on a multitude of considerations. Other systems, however, may be more automated and are capable of operating with little or no customer intervention.

Load control systems are classified into three categories—local, distributed, and direct control—according to the degree to which decisions are centralized and the extent to which the utility and customer interact before the load is manipulated. In a dlirect *control* system, the load is controlled by the utility without any immediate input in any form from the customer's side of the meter (see figure 5-1 2). This in the past has been the dominant form of load control.

In a *loca/ control* system, the load is controlled from the customer's side of the meter, without immediate input from the utility (see for example figure 5-1 3). With local control systems, manipulation of the customer's load is based solely on immediate input from only the customer's side of the meter. Utility involvement is re-

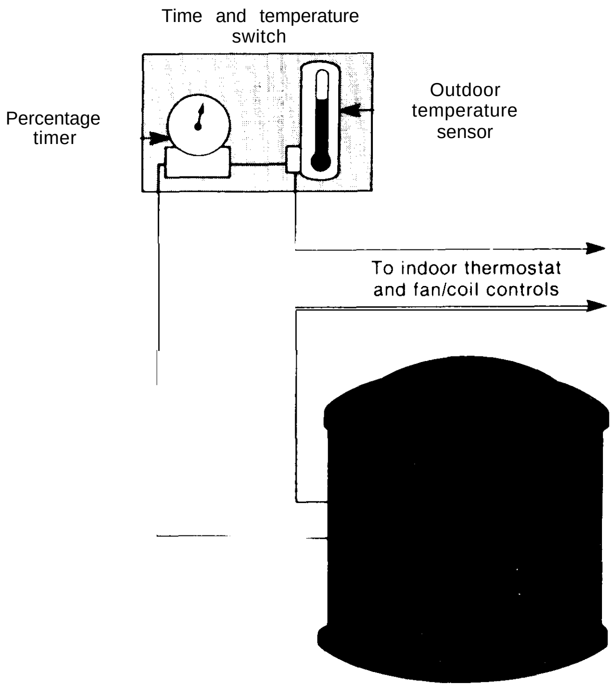
Figure 5-12.—A Direct"Control Load Management Technology: Domestic Water Heater Cycling Control



Domestic water heater cycling involves direct, real-time utility control over the operation of residential water heaters. Water heating is one of the few residential loads that is truly deferrable in that a water heater can be turned off for extended periods of time (up to 6 hours in some cases) without affecting the customer's lifestyle. By directly cycling water heaters (through a communication system, as opposed to using timers or other local controllers), the utility can vary when and how much control is exercised. Water heater cycling is generally exercised only during periods of peak demand or high marginal supply costs.

SOURCE: Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

Figure 5-13.—A Local-Control Load Management Technology: Temperature-Activated Switches



A temperature-activated time switch (T&T) is used to reduce air-conditioner operation time during utility peak periods. The two main components are an outdoor thermostat and an adjustable-percentage timer. When outdoor temperatures reach a preset limit, the timer regulates air-conditioner run times by a preset percentage, generally 75 or 50 percent (22.5 minutes on and 7.5 minutes off or 15 minutes on and 15 minutes off in every 30-minute period, respectively). Control is terminated when the outdoor temperature drops to the preset deactivation temperature.

SOURCE: Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

stricted to indirect inputs such as incentive rates. Local control devices have been encouraged where appropriate rates have been instituted. But their application has been limited in the residential sector, in part because such rates may require replacement of conventional meters with more advanced meters.

Between the direct and local control systems are variations collectively termed *distributed control* systems, where key decisions are made on both the utility and the customer side-of-the-meter, and where immediate inputs from both are possible. A distibuted-control system is pictured in figure 5-14. In EPRI's 1983 survey of utilities, it was found that, 86 percent of utility-sponsored load control projects— 1.2 million points–utilized direct control systems, while 278,000 points were controlled by distributed control systems, and 10,000 points fell under utility-sponsored local control programs. Many more points are locally controlled without the utilities' direct sponsorship, but with indirect utility support, usually through direct incentives and rate structures.[44]

The key problem encountered in all control systems is the management of loads in a manner which is satisfactory to the customer yet which provides an acceptable degree of control and predictability to the utility. The greater the utilities' direct control, the greater the risk of customer dissatisfaction. Conversely, systems which give the utility less direct control over the load—while perhaps alleviating communications and customer problems—risk reducing the utility's capacity to effectively manage the load. While direct control has dominated in the past, utilities are increasingly moving towards distributed and local centrol.

Discussed below are the two key technological components of load control: "decision-logic" technologies and central controllers and communications technologies.

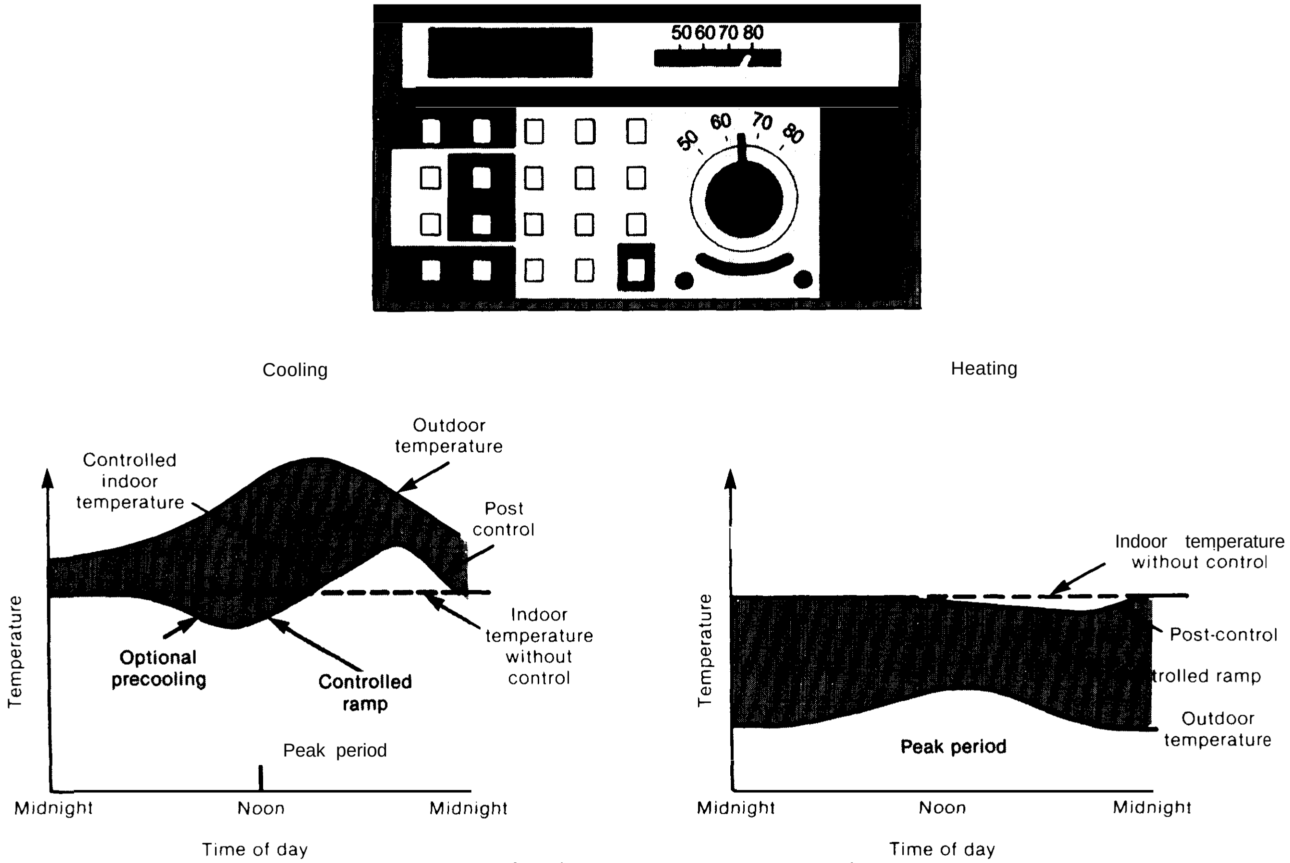
Central Controllers and Communications Technologies.– Direct and distributed control systems use technologies which fall into three categories: central controllers, transmission systems, and a receiver/switch at the customer's end of the system.[45] If the system communicates in two directions, a "transponder," which both receives and transmits, is required on the customer side of the meter; and a receiver must be in place on the utility's side of the meter to receive the information sent from the customer's transponder.

The controller generates commands which are encoded and dispatched through some transmission system, and received by the receiver which translates the encoded message and accordingly manipulates the load. While the hardware component of modern computerized controllers is

[44] Synergic Resources Corp., 1983 *Survey of Utility End-Use Projects*, op. cit., 1984.
[45] Ibid.

Figure 5-14.—A Distributed Control Load Management Technology: Load Management Thermostats

A load management thermostat is a microprocessor-based device that allows gradual indoor temperature increases or decreases in response to electric utility needs, thereby maintaining the natural diversity of loads while reducing the duty cycles of heating or cooling equipment. The result is a reduction in customer demand. The preset rate and length of temperature ramping can vary; fixed maximum and minimum temperature limits are also programmed into the device to prevent extremely uncomfortable conditions. Customers' thermostat setpoint adjustments are overridden during utility control periods. Emergency load shedding can also be accomplished using this device.



SOURCE: Battelle-Columbus Division and Synergic Resources Corp. *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

well developed and readily available commercially, the software is not. Recent utility experiences indicate that software deficiencies are the primary cause of difficulties in the implementation of load management programs. Current evidence suggests that software-problems are surmountable, but that effective software is likely to require considerable time to develop and refine, and to some extent must be customized for each utility.[46]

[46] Ibid

The communications system–which includes the transmission system and the receivers—has been subject of greatest discussion among utility operators. A variety of systems are available to choose from:

- **Radio:** This is currently the predominant communication system used for load management.
- **Power-1ine carrier (PLC) systems:** These systems use the utility's already installed transmission or distribution networks (or both) to carry the signal.

- **Telephone:** Telephone lines can be used in several different ways in communicating information to and from the utility.
- **Cable TV:** Using a cable modulator, the utility injects its signals into the cable network. Receivers are "hard-wired" to the cable at the customer's end.
- Hybrid communications systems: These systems incorporate two or more of the above systems in one load control system. This allows incorporation of the best features of both systems while avoiding some of their pitfalls.

Each of these communications systems has its advantages and disadvantages. They differ in the amount of information which can be communicated over any period of time; the reliability with which the communication takes place; the extent to which the communication system already exists; the cost and technical risk associated with the system; and the ease with which the utility can deploy and utilize the system in conjunction with a load management program. It is important to note that the hardware itself is in many instances fully mature, and involves little technical risk. In some cases, however, technical improvements remain to be made and costs may still be reduced.

The current debate over communications systems centers around which best serves the needs of the utility. These needs extend beyond the use of the communications network for load control, and touch on their application to remote meter-reading, distribution system automation,[d] and other uses. The needs also extend beyond the near term in that the utilities seek systems which are flexible enough to perform a variety of future tasks.

For example, one choice the utilities have is between one- and two-way communications systems. One-way systems are *sufficient* for load control, but two-way systems allow utilities to monitor more closely the results of load control by transmitting information from the customer to the utility. Furthermore, the two-way system may be exploited to obtain billing information which now requires a visit by the meter reader. And a two-way system may be used in automating the distribution system.

Complicating the utilities' evaluation of communications options is the fact that two basic options are available with respect to control and use. The utility may invest in a system which it alone controls and uses. Or the utility may invest in an information transmission system the control and use of which it *shares* with other users. Where others are involved, the costs of the system can be shared, but this arrangement also carries with it the possibility of technical problems in coordination as well as opportunities for conflict between the parties.

Hence, where shared communications systems are considered by utility investors, the cost advantages of such systems are weighed against the practical difficulties of cooperating with other people and organizations. The ultimate choice of the technology in such cases may depend as much on the ability of the utility to successfully overcome these difficulties as it does on the cost of the investment to the utility.[48] [49] [50]

Decision-Logic Technologies.—Distributed and local load control systems are distinguished from the direct control strategies in that information generated on the customer side of the meter promptly influences the manner in which the customer's load is managed. The locally provided information can be complemented by instructions transmitted either from the utility side of the meter through a rapid "real-time" communication system or from a pre-programmed utility-controlled device on the customer's premises.

The interpretation of locally derived information, the generation of the appropriate decisions, and the manipulation of the load can all be auto-

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[d]Distribution automation is the remote control of the distribution system which transmits electricity to customers from local substations; such control could offer significant improvements in overall power system operation.

[48]Synergic Resources Corp., 1983 *Survey of Utility End-Use Projects,* op. cit., 1984.

[49]David p, Towey and Norman M. Sinel, "An Electric Utility Explores the Use of Modern Communications Technologies, " *Public Utilities Fortnight/y,* vol. 113, No. 9, April 1984, pp. 23-33.

[50]Alan S. Miller and Irving Mintzer, *Draft Report: Evoking Load Management Technologies: Some Implications for Utility Planning and Operations* (Washington, DC: World Resources Institute, 1984).

mated in order to minimize or eliminate the need for active and routine human involvement on the customer's premises. This is done with "local decision-logic" devices which provide a degree of "local intelligence. " A variety of devices may serve this purpose. These vary in their cost, performance, and uncertainty. Some presently are available commercially at acceptable levels of cost and performance. Others must be technically improved, or their costs must be brought down before they will be deployed at significant levels. Generally, the major technical problem is in programming the devices so that they manage loads in ways that are acceptable to the customer while serving the utility's load management needs.

Ancillary Technologies Owned or Controlled by the Customer

In addition to the load management technologies discussed above, there are technologies which can be installed and operated by the customer to mitigate the potentially adverse effects of load control (direct, distributed, or local) on the customer. Among the technologies are two major possibilities:

1. **Ekctric and thermal energy storage:** A wide range of electric as well as thermal energy storage schemes exist for mitigating the effects of periodic curtailments in electricity supply. For example, a battery could be installed on the customer's side of the meter; the battery would be charged when power is more readily available and the customer could draw on it instead of from the grid during peak periods. If a load management program applied to an electric water heater threatens to leave the customer without sufficient hot water, a larger thermal storage device could be used. This device would be heated with electricity during off-peak periods. of particular importance is ''cool storage" for commercial establishments which uses electricity during off-peak periods to cool a medium such as water which then cools the building during peak periods. [51]

2. **Energy conservation:** Of course, energy conservation can also be employed as part of a mitigation program. For example, if curtailing the operation of an electric heater might result in lower house temperatures, insulation could be used to lower heat losses and keep household temperatures at a comfortable level.[52]

Some of these technologies are inexpensive, reliable, and present little risk. Others, such as large batteries systems, are less mature commercially and must overcome a variety of impediments before they could be deployed extensively (see chapters 4 and 9). Note, too, that the deployment of these technologies in many cases depends heavily on the rate structure or other incentives provided by the utilities.

Major Impediments to Load Management

Several difficulties must be overcome if load management is to be extensively implemented in the 1990s, It is necessary for utilities to develop a detailed understanding of the manner in which their customers now use electricity and are likely to use electricity in the future. To this must be coupled information regarding the utility's future supply of electric power. It also is important for utilities to identify and understand the many combinations of load management strategies which can be pursued. Each option must be weighed and compared not only to other load management options but also to other alternatives such as conventional generating technologies.

These difficulties are aggravated by the frequent lack of adequate analytical tools with which to evaluate load management. The planning and implementation of a load management program requires information and skills that differ from those needed for building powerplants and other more

51 See: 1) RCF, inc., *Commercial cool Storage Primer* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EM-3371. 2) San Diego Gas & Electric, *Thermal Energy Storage: Inducement Program for Commercial Space Cooling* (San Diego, CA: San Diego Gas & Electric, 1983). 3) Electric Power Research Institute, *Opportunities in Thermal Storage R&D* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EM-3 159.

52 Jerome P. Harper and R. E. Sieber (TVA), "Effects of Electric Utility Residential Conservation Programs on Hourly Load Profiles, " *Proceedings of the American Power Conference, vol. 45,* 1983, pp. 547-551.

traditional utility planning activities. SJ Moreover, as will be discussed in chapter 8, systematic analytical tools for comparing load management strategies with other strategic options are not widespread.

Even if economic benefits of load management are calculated to exceed direct costs, utility operators may prefer not to pursue load management. They may encounter difficulties in reaching agreements to jointly use communications networks with nonutilities. Access may be limited or prohibitively expensive; legal impediments may be encountered.[54] Or customers themselves may be reluctant to allow utilities to control their loads. While this has not been a widespread problem so far—given incentives customers to date have been very receptive[55]---it is a significant unknown that could potentially impede the deployment of direct and distributed load control technologies.[57]

[53]Energy Management Associates, Inc., *Issues in Implementing a Load Management Program for Direct Load Control* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EA-2904.

[54]" Justice Department States Cautious on Utility Telecommunications Ventures, " *Electric Utility Week,* June 18, 1984, p. 7.

[55]Angel Economic Reports and Heberlein-Baumgartner Research Services, *Customer Attitudes and Response to Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), RDS 95.

[56]Thomas A. Heberlein & Associates, *Customer Acceptance of Direct Load Controls: Residential Water Heating and Air Conditioning,* op. cit., 1981.

[57]Alan S. Miller and Irving Mintzer, *Draft Report: Evolving Load Management* Technologies: *Some Implications for Utility Planning and Operations,* op. cit., 1984.