Chapter 3

Context for Cogeneration

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Cogeneration has attracted widespread attention in recent years because of its potential for increased energy efficiency, and therefore, lower energy costs. A decision by an industrial concern, a commercial building owner, or a utility to invest in a cogeneration system will be based on an evaluation of the supply and price of fuel, regulatory considerations, the cost and availability of capital, tax incentives, and the technical, cost, and output characteristics of cogeneration relative to conventional separate electric and thermal energy systems. This chapter will review the institutional, regulatory, and financial context within which cogeneration must compete against conventional energy supplies, including the national energy context (supply of and demand for electricity and fuels), the structure and operations of the electric power industry (as they may affect a utility's choice of investing in a conventional baseload or peakload powerplant or in cogeneration), and the regulation and financing of cogeneration technologies. Subsequent chapters will describe cogeneration technologies and their cost and output characteristics, promising cogeneration applications in the industrial and commercial sectors and in rural areas, and the potential environmental and economic impacts of cogeneration.

NATIONAL ENERGY CONTEXT

Cogeneration systems could affect both the supply of and demand for fuels and electricity. The greater operating efficiency that can result from cogeneration's dual energy output could reduce the amount of fuel needed to supply electric and thermal energy for the industrial and commercial sectors. In many cases, depending on the fuel used by the cogenerator and by the utility capacity it would displace, the fuel saved with cogeneration could be oil or natural gas. Moreover, the widespread use of cogeneration could reduce the demand for electricity from central generating plants. In order to analyze these potential effects, it is first necessary to understand the current supply and demand picture for fuels and electric power—the national energy context in which cogenerators would operate.

This section discusses cogeneration with reference to the current and projected energy picture in the United States. First, the present energy situation and recent trends are reviewed briefly. Then, some projections of energy demand–particularly of electric and thermal demand in the industrial and commercial sectors—are discussed. In doing so, this section also briefly outlines some of the factors that could alter the energy picture in these sectors which, in turn, would affect the market penetration of cogeneration.

Current Picture and Trends

Table 6 presents 1980 U.S. energy demand by fuel and sector. Electricity is shown both as a demand and as a "fuel, " with losses distributed to each final demand sector.

Total energy demand in 1980 was 76.3 quadrillion Btu (Quads), a decline of 3.4 percent from the 1979 total of 79.0 Quads. The size of this decline—the largest annual drop in energy demand ever experienced by this country—was due in part to the very large increase in oil prices in 1979 and in part to investments in energy efficiency made as a result of the 1973-74 price rise. This can readily be seen by the 7.8-percent (2.9 Quads) decline in petroleum consumption from 1979 to 1980, and by the substantial decrease in the rate of growth in energy demand since the 1973 Arab oil embargo. Since 1973, overall U.S. energy demand has grown by approximately 0.8 percent annually, as compared with an average yearly growth of about 3.5 percent between 1950 and 1972. The most telling change in the overall U.S. energy growth picture, however, is that while energy growth has slowed dramatically, gross national product (GNP) has continued to grow at near historical rates. Table 7 shows the growth rates for both energy demand and GNP

Table 6.—1980 U.S. Energy Demand(Quads)

	Sector				
Fuel	Residential	Commercial	Industrial	Transportation	Electric utilities
Petroleum	2.05	2,34	8.88	17.99	3.00
Natural gas	5.91	1.92	8.41	0.60	3.79
Coal	0.10	0.10	3.35	—	12.12
Nuclear		—	—	—	2.70
Electricity	9.00	6,03	9.67	0.04	—
Hydro	—	—	—	—	3.09
Total	17.06	10.39	30.31	18.63	24.70

SOURCE: U.S. Department of Energy.

Table 7.—Ratio of Annual Energy Demand to GNP Growth Rates

Period	GNP rate (percent)	Energy demand rate (percent)	Ratio
1950-60	3.29	2.76	0.84
1960-70	3.85	4.24	1.10
1970-80	3.26	1.31	0.40

SOURCE: Office of Technology Assessment.

over the last three decades, as well as the ratio of energy demand to GNP growth rates for each of those decades. This latter measure indicates that a healthy economic growth rate can be sustained with a wide variety of energy growth rates, and demonstrates the conservation potential of the U.S. energy economy.

In addition to the cost effectiveness of conservation, other important national energy trends that have emerged during the past 8 years include the steady decline of domestic oil and natural gas production, and the increasing financial problems of electric utilities. The latter are, in large part, due to the large drop in electricity demand growth and the rapidly escalating costs of central station electricity generation. The unexpected rapid decline in the growth of electric energy demand (from 7.9 percent per year for 1950-72 to 3.5 percent annually for 1972-80) found most utilities with far greater capacity under construction than needed to meet the new growth. When it became evident that the lower growth rates were here to stay—in fact they might even get smaller—electric utilities deferred or canceled as much of their construction budget as they could. Many utilities were still left, however, with substantial excess capacity.

In addition, several factors combined to make new capacity much more expensive. These included longer construction times, increased environmental and regulatory review, higher interest rates, and high inflation. One major consequence of these considerations is that, in most cases, the marginal cost of new central station electricity now exceeds the average cost. As a result, electric utilities face severe financial problems, and those utilities that are experiencing demand growth or that need to displace oil-fired capacity may be unable to raise capital for any new plant construction (see "Electric Utilities Context," below).

Future Prospects

All energy demand projections show a continuation of the trend toward increased energy efficiency, although there is still considerable variation as to how much (see table 8). The range of the projections shown in table 8 is due principally to different assumptions about consumer responses to changes in energy prices. In all cases, however, these projections recognize that changes in demand will be the dominant factor in the energy future of the United States for the next few decades.

Table 8.—Comparison of Energy Demand projections (Quads)

Forecaster	1980	1990	2000
Energy Information Administration	76.3	87.0	102.5
Exxon	76.3	81.0	91.0
Edison Electric Institute	76.3	—	117.2
National Energy Policy Plan	76.3	80-90	90-110

SOURCE: Office of Technology Assessment

Another trend mentioned above–the decline in domestic petroleum and natural gas production—also is very likely to continue. In a technical memorandum, World *Petroleum Availability: 79802000,* OTA estimated U.S. oil production at 4 million to 7 million barrels per day (MMB/D) by 2000 compared to today's 10.2 MMB/D (52). Exxon also has projected a drop to about 7.5 MMB/D in 2000 (26). The Energy Information Administration (EIA), on the other hand, projects a slight increase above today's level to about 10.9 MMB/D (23). Despite the rapid increase in drilling activity since 1979, OTA has not yet *seen* any evidence to contradict findings of a net decline of between 3 to 6 MMB/D by the end of the century.

Natural gas production is even more uncertain due to the existence of large quantities of unconventional gas (Devonian shale, tight sands, coal seam methane, and geopressurized brine). For most types of unconventional gas, the uncertainty is not so much the size of the resource base, but the production rates that can be obtained and the production cost. The available estimates currently center on total natural gas production of 15 trillion to 17 trillion cubic feet (TCF) per year in 2000 compared to 19.5 TCF for 1980. If the price of natural gas rises to that of world oil, however, these same estimates show production in 2000 to be approximately the same as it is today. In any case, there is little probability that the Nation will see a significant increase in domestic gas production, and such an increase is even less likely for oil.

Implications for Cogeneration

The Nation is confronted with a combination of circumstances that favor continued emphasis on different, less costly ways to generate electricity, and on increased efficiency in electricity use. These circumstances have led to a resurgence in interest in the cogeneration of electricity and thermal energy. The relatively small size of cogeneration units compared to central power stations may offer significant short-term advantages for financing new capacity. Cogenerators will take much less time to build than central station plants and they represent smaller capacity increments that would allow rapid adjustment to changes in demand. Moreover, because cogeneration units are installed at or close to the point of demand, most or all of the energy requirements of many industrial plants and commercial buildings could be provided onsite with the added possibility of generating electricity for distribution through the utility grid. Finally, cogenerators' ability to use fuel for two purposes (electricity and thermal energy) greatly increases the overall utilization efficiency of that fuel. Thus, where electric utilities project continued reliance on oil and gas due to the unavailability or infeasibility of other fuels, or where cogeneration systems can use alternate fuels, substantial oil or gas savings may result.

The technical advantages of cogeneration have always been available. It is the advent of the economic and energy supply and demand conditions described above that adds potential fuel economy, financial, and planning advantages for cogeneration compared to central station electricity generation and conventional thermal energy combustion systems. Whether these advantages will prove sufficient to accelerate the growth of cogeneration will be determined largely by the amount and character of demand for electricity and thermal energy in the commercial and industrial sector, and by the future financial health of the electric utility sector.

Electricity Supply and Demand

Perhaps the most critical factor in cogeneration economics is the demand for electric power. The Public Utility Regulatory Policies Act of 1978 offers economic and regulatory incentives to cogenerators that enable utilities to defer or cancel new powerplants and decrease oil and gas use. A zero or low growth in electricity demand, however, could undermine these incentives by reducing the need for cogenerated electricity and, therefore, reducing the economic attractiveness of cogeneration. Moreover, where the utility is primarily dependent on coal, nuclear, or hydroelectric plants, or where it plans to convert existing oil-fired capacity to alternate fuels, cogeneration will only be attractive if it also can use alternate fuels and can offer substantial financial advantages.

Currently there is considerable uncertainty about future electric power demand growth; the Solar Energy Research Institute (SERI) projected a 0.4 percent per year increase under their least cost approach (61), while the North American Electric Reliability Council (NERC) estimates a 2.9 percent annual growth rate (48). In terms of capacity requirements, the SERI projection could be met by 620 gigawatts (GW) of capacity operating at the current capacity factor of 45 percent. Further, SERI shows that 577 GW could be available in 1985 assuming completion of all plants scheduled to be on-line in 1985, and the retirement of all plants built before 1961 and of all oil and natural gas plants built between 1961-70 (61). Therefore, under the SERI least cost approach, very little new capacity would be needed past 1985, and any cogeneration added after that would be likely to substitute for electricity from existing coal, nuclear, or hydroelectric plants. Under the NERC case, however, capacity is projected to reach about 900 GW by 2000, an increase of 300 GW over present capacity. Even then, NERC estimates that the capacity factor would have to increase to 50 percent to meet their projected energy demand. Accounting for retirements and conversion of oil and natural gas, about 50 percent more new capacity would have to be added under NERC projections than now exists (49). In this case, cogeneration could have a very large market potential.

The future demand for electricity will be determined by the relative prices of electricity and competing fuels (including conservation measures), by the development of technologies that use electricity more efficiently (e.g., process equipment, appliances), and by consumers' perceptions about the stability of oil and natural gas resources. Currently, average electricity prices in the commercial sector are about 2.5 times distillate fuel oil prices and five times natural gas prices on a delivered Btu basis. * For industry, both of these price ratios are about 2 to 1. The ratios have decreased by 20 to 60 percent from those in 1970, however.

*As will be discussed below, differences in end use efficiency between equipment using electricity and that using natural gas or fuel oil make price comparison on a delivered Btu basis alone, incomplete.

Continuation of the low rate of growth in electricity demand, coupled with the current excess of generating capacity, may keep the rate of growth in electricity prices rather low over the next several years. If prices do remain somewhat stable, then the difference between electricity prices and oil and gas prices would be likely to become even smaller. However, the current decline in the real price of oil could alter this trend. Furthermore, if the oil price decline continues for the next few years, natural gas price increases following decontrol also are not likely to be so dramatic as originally thought. Therefore, the ratio of electricity prices to oil and natural gas prices would not decline for some time. At this point, it is most likely that the ratio will decline, although more slowly that previously anticipated. The price trajectories used in the analysis of commercial cogeneration in chapter 5 also project that the ratio will become smaller.

Such growth rates would continue the trend toward price closure between electricity and natural gas or distillate fuel oil. If these trends are combined with the development of technologies for buildings and industry that use electricity more efficiently than equivalent oil or natural gas burning technologies that provide the same services (e.g., space heating, reheating of finished metals), the costs of providing these services with electricity could become lower than with oil or natural gas. For example, in many areas, efficient electric heat pumps can provide space heating more economically than oil furnaces. There are even a few regions where space heating with electric heat pumps is cheaper than with natural gas furnaces.

Natural gas and oil are the primary energy sources for industrial processes, supplying both direct heat (such as catalyzing chemical reactions and heat treating) and process steam. The major use of electricity in industry is to run motors. Whether technologies that use electricity could economically replace direct heat or process steam in industry is much less certain than in the commercial sector. Some possibilities include microwave, infrared, or dielectric heating, very efficient electric motors for replacing steam mechanical drives, and pulsed current devices for surface reheating of metals.

It is possible, then, that the growth of electricity demand could increase sharply toward the end of the decade. * However, the extent of any increase in industrial or commercial demand will depend on the size of the dollar savings achieved by switching to electricity relative to the required capital investment. Conversion is much more likely for new buildings and plants than for existing facilities. Therefore, unless there is significant new development in energy intensive industries for which more economical electric technologies are available and accepted, the growth rate of industrial use of electricity is not likely to change substantially for the remainder of the century.

It is this uncertainty of future demand that provides a potentially important role for cogeneration. If electricity use in buildings and industry did increase substantially, electric utilities could be strained financially if they tried to meet the increased demand with new central station capacity. Further, attempts to accommodate demand growth with central station capacity could lead to a rapid increase in electricity prices. This is because the marginal cost of electricity—the cost of a new plant—is often considerably higher than the average cost. Therefore, as new capacity becomes a larger fraction of the total electric utility plant, the average cost will grow closer to the marginal cost. Cogeneration could help alleviate these pressures, particularly in the first years of an increase in demand. The small size of cogeneration systems would allow rapid and fairly precise matching of supply and demand, and with much smaller increments of capital. This would greatly reduce the risk of building excess capacity or having to defer or cancel capacity under construction should demand growth suddenly slow or stop. Moreover, because cogeneration supplies thermal energy, it could at least partially offset increases in electricity demand due to a rapid rise in the use of electric heating. Cogeneration's competitiveness would then turn on the difference between the cost of purchasing electricity plus supplying heat, and the fuel and operating and maintenance costs of a cogeneration system. Finally, the avoidance of extensive new additions to transmission and distribution systems also might alleviate some of the electric utilities' capital problems.

*The extent to which electricity can be substituted economically for other energy sources in buildings and industry will be examined in detail in forthcoming OTA studies on oil disruption and on electric utilities.

However, if utilities are able to raise capital easily, or if demand does not increase in the face of stable prices, central station powerplants fueled with coal, uranium, or hydropower may be preferred to oil- or gas-fired cogeneration systems. These alternate energy sources probably would be cheaper than the oil or natural gas likely to be used in most cogeneration systems in the near term. Therefore central station electricity—even with a substantially larger capital cost per kilowatt than cogeneration capacity—is likely to be cheaper than cogenerated electricity despite cogeneration's higher overall fuel efficiency.

Thermal Energy Demand

The second major influence on the growth of cogeneration is future thermal energy demand in buildings (space and water heat) and industry (direct heat and process steam). We have already discussed how some of this future load may be met by electricity rather than by direct combustion of fossil fuels. In addition, available conservation opportunities will slow thermal demand growth and could even reduce thermal energy use (by 2000) from the 1980 levels. Conservation will affect electricity use as well, and even if significant conversion from other fuels to electricity (as discussed above) does occur, electricity demand growth in these sectors still could be kept low. Table 9 shows two estimates of direct combustion heat requirements for commercial buildings and industry for 2000 compared to 1978. As can be seen, current thermal demand in industry is more than twice that of commercial buildings. Moreover, under either the EIA or the SERI projection, the difference would become even more pronounced.

Table 9.—Thermal Energy Demand (Quads)

	Buildings	Industry	
Year	Space/water heat	Direct heat	Steam
1978	4.5	3.8	6.8
2000 (EIA)	3.8	5.0	9.3
2000 (SERI)	1.6	3.7	6.6

SOURCE: Office of Technology Assessment

The SERI estimates in table 9 are based on a least cost approach using conservation technologies that cost the equivalent of up to the 1980 average cost of oil and electricity ($7.50/MMBtu and $.057/kWh respectively) (60). The EIA projections are derived from economic and engineering models and reflect judgments about actual consumer response to changing energy prices (22). In either case, cost-effective conservation opportunities for commercial buildings could reduce fuel requirements for space and water heating from 15 to 65 percent. For industry, EIA estimates a 37-percent increase in steam growth while SERI projects a 3-percent decrease (see the section on "Industrial Cogeneration Opportunities" in chapter 5 for an analysis of steam growth projections).

These analyses indicate that cogeneration will have greater potential in the industrial sector than in commercial buildings as far as supplying thermal energy is concerned. Both EIA and SERI analyses imply that in the commercial buildings sector, cogeneration will have to compete with central station electricity and with fuel freed by conservation in meeting future space and water heating demand. When the low load factor inherent in buildings' heat load is added, the economic potential of cogeneration is decreased further (see ch. 5). In essence, conservation can considerably reduce the opportunity to take advantage of cogeneration's high fuel utilization efficiency.

The air-conditioning demand of buildings also offers a potential market for thermal energy from cogeneration. In 1980, over 98 percent of all commercial air-conditioning was electric. For these buildings, the use of cogenerated steam for cooling would require conversion to either absorption units or steam-driven compressors. Where it is economic to do so, such conversion would increase the baseload steam demand and therefore the building's thermal load factor. By 2000, SERI and EIA project cooling demands of 2 and 4 Quads of primary energy, respectively.

Conclusion

The attractiveness of cogeneration will depend, to a large extent, on energy demand in the commercial and industrial sectors, on the balance between thermal and electric loads, and on the overall demand for electricity. These, in turn, depend heavily on the price of energy–particularly the relative prices of electricity, distillate fuel oil, and natural gas. It is fairly certain that energy demand will grow much more slowly than in the past. The range of possible growth rates, however, is large. Lower growth rates, while not necessarily changing the economics of cogeneration, will clearly reduce the potential market as well as the net fuel savings. Further, a very low growth rate for electricity is likely to dampen price increases and reduce the price paid by utilities for cogenerated power, both of which would reduce the economic attractiveness of cogeneration. However, the uncertainty of future electricity demand and the economic problems caused by a severe mismatch between load growth and capacity growth make small capacity additions potentially very desirable in the short term. Therefore, while conservation through increased efficiency is likely to be the most economic route to choose for at least the next several years, there appears to be a potential role for cogeneration, particularly in the industrial sector where thermal and electrical demands are likely to remain large.

ELECTRIC UTILITIES CONTEXT

Future supply of and demand for energy and electricity, as discussed above, will be a major factor in determining the role cogeneration will play in the Nation's energy future. Equally important in defining that role will be the electric power industry. Cogeneration systems may be owned and operated by electric utilities, or they may be installed by former utility customers who now provide some or all of their own electric power needs and who may even supply power to the utility. In this context, cogeneration must compete, both technologically and economically, with well established electric and thermal energy conversion and distribution systems as well as with alternate energy forms and conservation. The elements of this competition—both on a site-specific and a national energy policy basis—will be wide ranging, encompassing the technological, fuel use, and institutional characteristics of the electric power industry, as well as the financing, regulation, and operations of technologies that supply energy for commercial and industrial applications.

This section will review the general electric utility context within which cogeneration systems will compete. The following section of this chapter will analyze the present institutional and regulatory context specific to cogeneration.

The Electric Power Industry

Current operations of electric utility systems are diverse, encompassing a wide range of technical and institutional configurations. These include the number, size, and type of generating plants; the amount of electricity consumed by customer classes and their regional load profiles; and the different types of institutions that supply power, coordinate specific utility functions, and regulate the power industry. Support activities include the production and acquisition of fuel supply and of the necessary equipment for fuel handling and storage, and for electricity generation, transmission, distribution, and consumption.

A wide array of institutions has evolved to perform the functions listed above. The U.S. electric power supply system is composed of over 3,400 separate entities, including private, public, and cooperative utilities, joint action agencies, Federal power agencies, power pools, and electric reliability councils. In 1980, these systems had 619,050 megawatts (MW) of installed generating capacity to supply close to 93 million customers with about 2.3 trillion kilowatthours (kWh) of electricity (see table 10) (55). The utilities in the electric power system obtain financing from a variety of sources including banks, insurance companies, traditional stock and bond markets, and Federal programs; their financial and technical operations are regulated at the Federal, State, and local level. Finally, both the production and consumption of electricity are supported by innumerable institutions that manufacture, distribute, install, and service equipment, tools, and appliances. All of these factors together make the electric utility industry the largest in the United States in terms of capital assets and issuance of stocks and bonds.

Utility Organizations

The organizations that supply electricity in the United States include private or investor-owned utility companies; publicly owned utilities such as State, county, or municipal systems, and Federal power agencies; rural electric cooperatives; joint ownership organizations; and groups of utilities that coordinate their operations to improve efficiency and reliability.

Private utiiities are owned by their investors and generally are granted territorial franchises by State or local governments. Most investor-owned utilities (IOUS) generate their own electricity, and some are part of vertically integrated corporations that own their fuel supply (e.g., "captive" coal mines) or other support activities.

Table 1O.–U.S. Electric Power System Statistics, 1980

Type of system (and number)	Installed capacity		kWh generation		Customers		Electric operating revenues		Net electric plant investment	
	Megawatts	Percent	Millions of kWh	Percent	Number	Percent	Millions of dollars	Percent	Millions of dollars	Percent
Local public systems (2,248)	67,568	10.9	204,880	9.0	12,467,700	13.5	$12,224	10.8	$34,100	11.9
Privately owned systems (217)	476,979	77.1	1,782,545	78.0	70,620,300	76.2	87,062	76.9	207,555	72.4
Rural electric cooperatives (924)	15,425	2.5	63,557	2.8	9,523,600	10.3	9,707	8.6	23,892	8.3
Federal power agencies (8)	59,078	9.5	235,051	10.3	13,300	0.01	4,238	3.7	21,100	7.3
Total	619,050	100.0	2,266,033	100.0	92,624,900	100.0	$113,231	100.0	$286,647	100.0

aDoes not Include nuclear fuel.

SOURCE: Office of Technology Assessment from "Public Power Directory," Publlc Power, January-February 1982.

IOU companies dominate power generation in the United States today. The 217 IOUS represent about 6 percent of the total number of utilities, but those 217 own approximately 77 percent of all installed generating capacity and generate about 78 percent of the electricity produced (see table 10). In 1977, approximately two-thirds of the IOUS had a peak demand in excess of 100 MW, and about 12 percent had a peak demand greater then 3,000 MW (21). Because of the capital intensity of the electric utility industry, with total operating revenues of over $113 billion in 1980 and net electric plant investment of over $286 billion, the domination of the industry by a relatively few IOUS means that they also determine the role of utilities in financial and other markets.

publicly owned utilities include municipal, public utility districts, and State and county systems. The authority to establish a public utility derives from the State government, and a few States (e.g., New York, Nebraska) currently have their own systems. However, most States have delegated this authority to county or municipal governments.

The relatively large number of publicly owned utilities, in contrast to their small share of the electricity market (see table 10), reflects their small size. Most of these systems only purchase wholesale power and distribute it to their customers; those municipal that do generate have very small loads (fewer than 100 publicly owned utilities have peak demands in excess of 100 MW) (21). Roughly 71 percent of the local public power systems purchase all their electricity, while about 6 percent own sufficient generating capacity to supply all their needs. The remaining 23 percent of public utilities generate some portion of their needs and purchase the remainder (55).

Cooperative utilities represent a different type of public ownership. The co-ops are nonprofit economic entities that are owned and managed by their customer members. Members' shares in the co-op may be plowed back into the operation and/or expansion of the business as patronage capital in order to keep the cost of co-op service as low as possible, or the patronage capital may be "rotated"—essentially paid out as dividends–if the co-op's equity ratio is 40 percent or higher.

Rural electric co-ops comprise a vast operating network of over 900 local and regional electric systems in 46 States which own and maintain nearly 44 percent of the Nation's electric distribution lines, and whose service territories encompass 75 percent of the land area of the United States. The rural electric system is a two-tiered operation, including 870 local distribution co-ops and 54 generation and transmission co-ops (G&Ts). The 870 local co-ops purchase electricity and distribute it to their own rural customers, while G&Ts generate and/or transmit electricity primarily for local distribution co-ops. Some G&Ts also sell electricity wholesale to municipal and IOUS, while distribution co-ops may purchase power from a combination of sources, including G&Ts, Federal power agencies, and IOUS (16).

Still another form of public utility ownership is represented by Federal power marketing agencies. The Federal role in electricity generation dates back to the Reclamation Act of 1906, which empowered the Bureau of Reclamation to produce electricity in conjunction with Federal irrigation projects, and to dispose of any surplus power to municipal utilities (39). The second Federal power marketing agency was the Tennessee Valley Authority (TVA), which was established in 1933 as a multipurpose river project with responsibility for flood control, regional development, hydroelectric power generation, and other activities. Today, it is the single largest electric utility in the country, with a total system capacity of over 31,000 MW. Approximately 65 percent of TVA's sales are at wholesale to municipal utilities and rural electric co-ops. The remainder is sold to private industries, other Federal agencies, and private power companies (55).

Other Federal power agencies include the Bonneville Power Administration, which was established in 1937 and which markets power from hydroelectric projects constructed by the Army Corps of Engineers and the Bureau of Reclamation in the Columbia River Basin and operates the Nation's largest network of long-distance high-voltage transmission lines; the Southwestern Power Administration, which was set up in 1944 to market power from Corps of Engineers projects in Arkansas, Missouri, Oklahoma, and Texas; the Southeastern Power Administration, created in 1950 to market power from Corps projects in 10 Southeastern States; the Alaska Power Administration, established in 1967 to operate and market power from Federal hydroelectric projects in Alaska; and the Western Area Power Administration, which was set up in 1977 and incorporates Federal power marketing and transmission functions formerly performed by the Bureau of Reclamation and markets power from a number of Corps hydroelectric projects (55).

A hybrid form of public ownership is the joint action agency, in which two or more public power systems pool their plans to purchase power or to finance total or partial ownership of generation and/or transmission systems. Where the local public utility system is no longer adequate or economical and low-cost Federal power is not available, joint action agencies can place public power systems in a more advantageous cost and supply position, allowing even the smallest electric utilities to realize economies of scale (4). Joint action may also provide publicly owned utilities with more flexibility in choosing fuels and types of generating capacity while avoiding the risks of a single-shot investment in one plant. IOUS may choose to participate in joint action agencies to reduce plant construction costs or to obtain lower cost financing (32).

Joint action agencies are authorized by State legislation and membership arrangements vary. They may include statewide areas (e.g., Municipal Electric Authority of Georgia), correspond to IOU service areas (such as in North Carolina, which has three agencies, one for each of the State's major IOUS), or be determined according to both geography and perceived mutual interests (e.g., the five Minnesota organizations). Some joint action agencies, such as the Missouri Basin Municipal Power Agency, have members from several States. As such, they cannot finance projects themselves but must rely on the members' funding abilities. In 1981, there were 49 publicly owned joint action agencies in 31 States (55).

Since the 1920's, all the types of utility systems described above have been interconnected and their operations coordinated to some degree in order to reduce costs by increasing the productivity of the resources employed in the generation and transmission of electricity, and to improve reliability by applying the combined resources of several systems to a contingency on any one. These intersystem agreements now comprise approximately 20 formal organizations known as power pools. The degree of coordination among utilities in power pools can range from very loose agreements for exchanges of energy; to some coordination of planning, construction, operation, and capacity reserves; to complete integration with joint planning on a single system basis, centralized dispatch of generating facilities, and strict contractual requirements for generating capacity and operating reserves (29).

In general, the potential economic benefits of pooling include reduced investment costs through economies of scale in building larger generating units and through lower reserve margins that result from reducing the ratio of generating unit size to combined system peakload; greater operating economies through increased load diversity, reduced operating costs per unit output for larger plants, and fuller use of the lowest cost capacity available on the system; and increased savings through coordinated construction programs that minimize the costs of temporary excess capacity that may result from the addition of large generating plants. The potential reliability benefits of power pools derive from access to support from other systems, and may be realized either through a reduction in reserves needed to achieve a certain level of reliability or through an increase in the level of reliability of the coordinated systems (29).

Electric reliability councils represent a second form of coordination among utilities. A Federal Power Commission (FPC) investigation of the 1965 blackout in the Northeast stressed the need for greater reliability and coordination among electric utility companies. In response to FPC findings, NERC and nine regional councils *were* formed in the late 1960's (see fig. 8), representing about 95 percent of the Nation's generating capacity. Each regional council consists of a rep-

Figure 8.—North American Electric Reliability Council Regions

ECAR	East Central Area Reliability Coordination Agreement	
ERCOT	Electric Reliability Council of Texas	
MAAC	Mid-Atlantic Area Council	
MAIN	Mid-America Interpool Network	
MARCA	Mid-Continent Area Reliability Coordination Agreement	
NPCC	Northeast Power Coordinating Council	
SERC	Southeastern Electric Reliability Council	
SPP	Southwest Power Pool	
WSCC	Western Systems Coordinating Council	

SOURCE: North American Electric Reliability Council.

resentative from each of the major utilities in the region and from groups of small utilities in some regions.

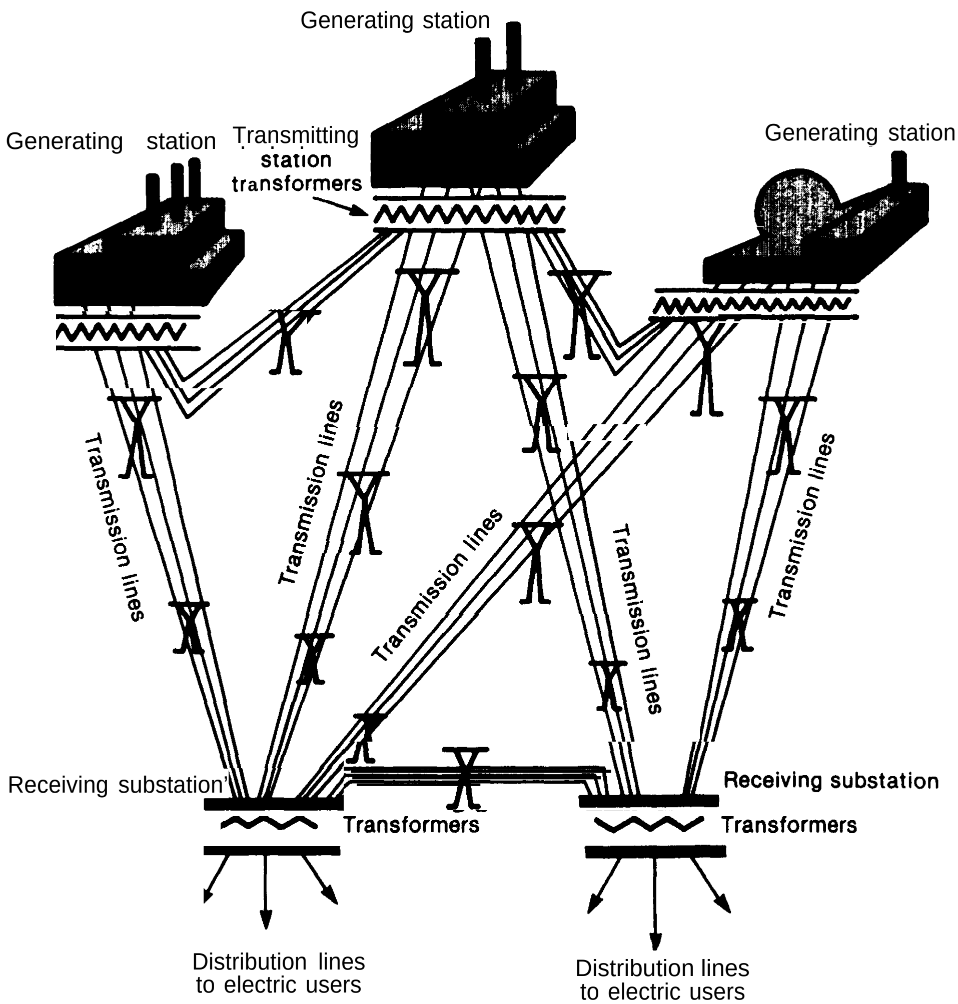
The regional councils develop voluntary standards for those aspects of bulk power supply that affect the regionwide reliability of service (e.g., design criteria for transmission facilities). NERC aids in the coordination of policy issues among the regional councils, and provides industry information, comment, and recommendations about the reliability and adequacy of bulk power supply at the national level. In addition, NERC is responsible for the development and maintenance of nationwide standards for interconnected operation (18).

Technical Aspects of the Utility industry

A conventional power system can be described as the coordinated operation of generating units, high-voltage transmission lines, and subtransmission and distribution networks. Figure 9 shows a typical power system structure.

The primary consideration in an electric power system is to serve the electric loads, or power requirements, in a given area or region. The power

Figure 9.—The Generai Patterns of an Eiectric Power System

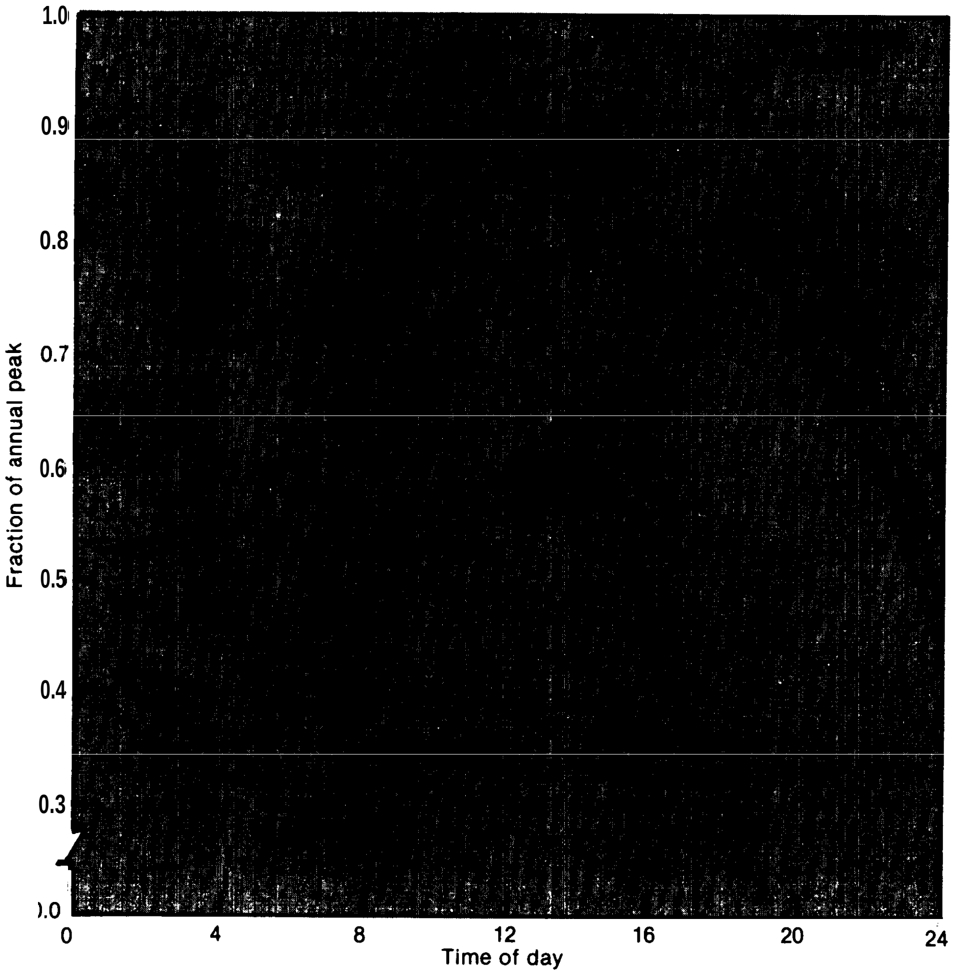


SOURCE: Economic Regulatory Administration, *The National Power Grid Study, Volume //(Washington,* D. C.: U.S. Department of Energy, DOE/ERA-0056-2, September 1979).

requirements include all devices or equipment that convert electricity into light, heat, or mechanical energy, or otherwise consume electricity (e.g., aluminum reduction), or the requirements of electronic and control devices. The total load on any power system is seldom constant; rather it varies with hourly, daily, seasonal, and annual changes in the service area's requirements (see fig. 10). The minimum system load for a given period is termed the baseload, while maximum requirements (usually resulting from temporary conditions) are called peakloads. Because electric energy currently cannot be stored in large quantities, generating plant operations must be coordinated closely with fluctuations in the load, and large utility systems usually have separate generating plants sized to meet base, intermediate, and peakloads.

Table 11 shows the current U.S. generating capacity by type of prime mover. The choice of capacity type is a function of service needs, economic and financial considerations, resource constraints (e.g., fuel, land, water), potential environmental impacts, future growth, politics, regulatory requirements, and management prefer-

Figure 10.—Daily Load Shapes for Five Representative Weekdays (North Central Region, 1980)



SOURCE: Decision Focus, Inc., *Evacuation of the Economic Benefits of **Decentralized Electric Generating** Equipment Connected to a **Utility Grid*** (contractor report to OTA, October 19S0).

Table 11.–Installed Generating Capacity, by Type of Prime Mover, 1978

	Total		Hydroelectric		Conventional steam		Nuclear steam		Internal combustion	
	Thousands of kilowatts	Percent	Thousands of kW	Percent	Thousands of kW	Percent	Thousands of kW	Percent	Thousands of kilowatts	Percent
Investor-owned utilities	453,647	76	23,847	4	383,024	66	44,984	8	1,792	< 1
Municipal utilities	34,426	6	4,694	< 1	25,511	4	963	< 1	3,258	< 1
State systems and public utility districts	25,322	4	11,975	2	9,245	2	4,059	< 1	43	< 1
Rural electric cooperatives	11,635	2		<1	11,073	2		< 1	430	< 1
Federal	54,282	9	30,431	5	20,376	4	3,456	< 1	17	< 1
Total	579,312	100	71,014	12	449,231	78	53,527	9	5,540	1

SOURCE: Edison Electric Institute, Statistical *Yearbook of the Electric Utility Industry, 1980* (Washington, D. C.: Edison Electric Institute, November 1981).

ences. In general, fossil and nuclear fueled steam plants and many hydroelectric facilities are used for baseload and intermediate-load generation while some hydro equipment (usually pumped storage) and combustion turbines are used to supply peaking power.

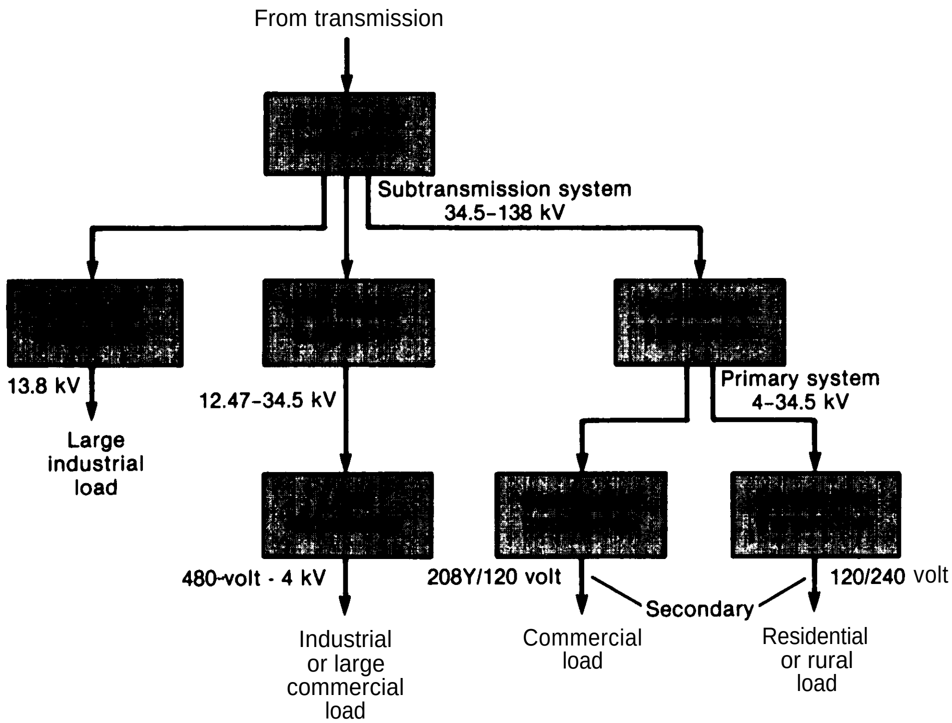
The trend in recent years has been to construct large baseload plants in order to capture economies of scale. Nuclear plants usually exceed 1,000 MW in nameplate capacity and most of the existing fossil steam plants are larger than 5oo MW. However, as capital costs and construction times increase and it becomes more difficult to finance large powerplants, some utilities are turning to smaller equipment that may use unconventional fuels. Where the service needs are not expected to grow rapidly, small units such as cogenerators may improve load factors while alleviating utility financial problems in the short term, although their longer term financial and system planning advantages are uncertain (see ch. 6).

In order to serve the electric loads of an area adequately, a utility must plan not only for baseloads and peakloads, but also for system reliability during scheduled and unscheduled outages (e.g., equipment maintenance, storm damage) and for demand growth. To some degree, system reliability can be achieved through interconnections with other utilities (i.e., power pooling), but utilities also must incorporate reserve margins into their planning. Reserve margins are the installed available capacity in excess of that needed to meet the system's peak demand when due consideration is given to maintenance requirements, random equipment failure, or other contingencies. The amount of reserve capacity required in a given situation depends on the reliability criterion, the behavior of individual generators, the unit size mix, and the interconnection support available. The usual planning procedure is to specify a reliability level or loss of load probability, such as an expected deficiency of 1 day in 10 years, and optimize capacity expansion so that this criterion is always met (3 S). The accepted industry minimum value is about 20 percent. In 1979, the average reserve margin for IOUS was around 36 percent of peakload (20). Some utilities have reserve margins above so percent, while others are below 10 percent.

Once electricity has been generated, its voltage is stepped up with power transformers and it is transmitted to the load center. High-voltage transmission lines (69 kilovolts (kV) and above) are used to transfer bulk power from the generating plant to a substation or bulk purchaser, and to interconnect utility systems for greater efficiency and reliability. Such lines are built to accommodate power flows in either direction in order to facilitate interconnection among systems.

After the bulk power has been transmitted to the demand center, it goes into the distribution system, which supplies electric energy to the individual user or consumer. The distribution system includes the primary circuits and the distribution substations that supply them; the distribution transformers; the secondary circuits, including the services to the consumer; and appropriate protective and control devices (see fig. 11). A transmission substation transforms power to subtransmission voltage (below 69 kV). It is then distributed to various distribution substations, load substations, and distribution transformers, where the voltage is stepped down further to match residential, commercial, and industrial needs. Once the electricity enters a local distribu-

Figure 11.—Typicai Eiectric Distribution System (three.phase)



SOURCE: *McGraw-Hill Encyclopedla of Energy (New* York: McGraw-Hill Book Co., 1976).

tion system, the power usually only flows one way in order to protect electrical workers and equipment. Special equipment is thus needed for onsite generators that feed power back to the grid (see discussion of interconnection in ch. 4).

Economic and Regulatory Aspects of Utility Systems

Electric utilities are among the most capital-intensive and highly regulated industries in the United States, and the two aspects of the industry are integrally related. The rates charged for service-as determined by State or Federal regulation—are the primary factor in utility economics. But the economics of electric power supply and demand also may be affected by financing and its regulation as well as by regulation of utility services and operations. These aspects of utility regulation and their effects on the production and consumption of electricity—and thus on the potential role of cogeneration—are discussed below.

UTILITY RATES

In exchange for the privilege of operating as a natural monopoly, utility practices are regulated in the public interest. The primary form of such regulation is the determination of the rates utilities can charge for their services. State public service commissions (PSCS) traditionally have controlled rates for intrastate sales of electricity, while the Federal Government has had jurisdiction over sales for resale in interstate commerce since 1935.

State Regulation.–Each of the States (except Nebraska, where all electricity is supplied through a State-owned and operated utility system) has a PSC established by law to regulate utilities. The degree of State regulation varies. Ail PSCS regulate the rates of IOUS, while 19 commissions have some authority over publicly owned utility rates, and 29 regulate cooperatives (30). Where the PSC does not have such authority, public utilities are self-regulating through the municipal or county government.

Determining the rates a utility charges for its services is a two-step process. The PSC must decide first, how much money the utility needs (the revenue requirement) and second, how those funds will be collected (the rate structure or rate schedule). A utility's revenue requirement is the total number of dollars required to cover its operating expenses and to provide a fair profit. The revenue requirement is usually expressed in formula form as follows:

$$RR = E + d + T + (V - D) R$$

in which

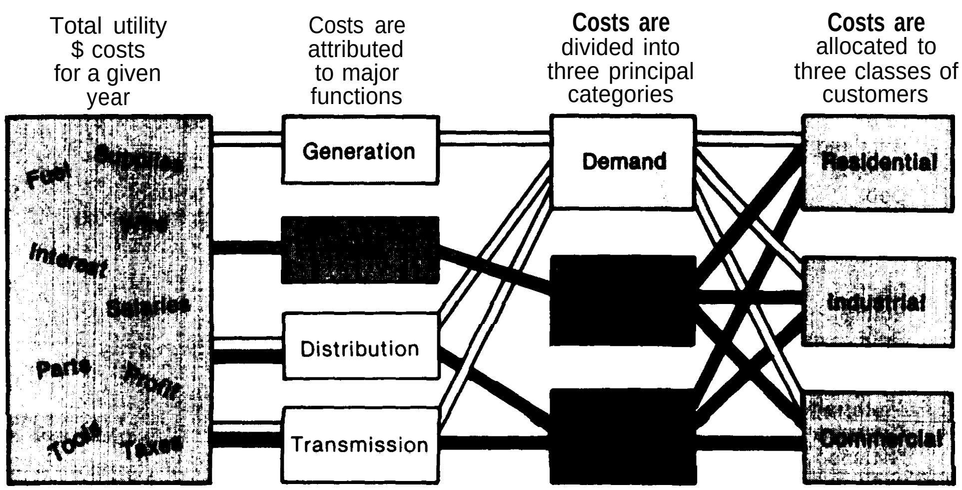
- RR = revenue requirement
- E = operating expenses
- d = annual depreciation expense
- T = taxes, including income taxes
- V = gross valuation of the property serving the public
- D = accrued depreciation
- R = rate of return (a percentage)
- $(V - D)$ = rate base (net valuation)
- $(V - D) R$ = profit, expressed as earnings on the rate base, plus interest on debt (53).

The **rate schedule allocates the revenue requirement among a utility's customers. The problem of cost allocation arises because most electricity is produced in jointly utilized equipment and its cost must be assigned to the customer classes involved (36). First, costs directly attributable to a particular class or customer (e.g., the distribution line from a substation to a factory) are identified and segregated. Second, the remaining costs are arranged so that they can be apportioned among the various groups of customers jointly responsible. Third, those costs are distributed in accordance with some physically measurable attribute of the customer class.**

in accomplishing the last two steps, costs are arranged according to function (such as production, transmission, and distribution), and then either assigned to demand, energy, or customer cost categories, or simply classified as fixed or variable (see fig. 12). Demand costs (the fixed rate base and expense items related to peak or average demand) are generally the most difficult to allocate and have become controversial in the setting of rates for backup service to cogenerators (see discussion of rates in next section). Energy costs can be directly allocated to customer classes based on the number of kilowatt-hours consumed by the group, and thus do not pose a problem (36).

Federal Regulation.–Federal regulation of electricity prices began in 1920 with the authority to set rates for interstate sales of power from federally licensed hydroelectric projects. The financial abuses of the 1920's and early 1930's, however, revealed a need for a more extensive national role, and the Federal Power Act of 1935 expanded Federal jurisdiction to include all sales of electric energy at wholesale in interstate com-

Figure 12.–Allocation of Electricity Costs



SOURCE: Office of Technology Assessment.

merce. The States retained exclusive jurisdiction over intrastate and retail electricity sales until passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which required the Federal Energy Regulatory Commission (FERC) to establish standards for PSCS to consider in setting retail and certain wholesale rates (56).

The Federal Power Act of 1935 requires that all rates and charges of any electric utility for the transmission or sale of power subject to FERC (formerly FPC) jurisdiction be just and reasonable as well as nondiscriminatory. Each utility must regularly file with FERC schedules that show such rates and charges, and the classifications, practices, and regulations that may affect them. FERC rate proceedings are similar to those of State commissions: FERC first determines the utility's revenue requirement and then approves a rate schedule designed to meet that requirement. In such proceedings, FERC traditionally has employed the same cost-based formulae used by PSCs (3).

Although only about 10 percent of the revenues realized by IOUS are from wholesale transactions subject to Federal jurisdiction, FERC still has a broad opportunity to influence State ratemaking. For example, States may be reluctant to introduce innovative rate structures for fear of placing utilities within their jurisdiction at a competitive disadvantage. Innovation at the Federal level can provide the experience necessary for State adoption of innovative rate designs. Moreover, FERC'S ability to examine cost trends and pricing practices on a regional or nationwide (as opposed to local) scale may reveal to States opportunities for ensuring greater economy in electric power supply.

FINANCING

The second major factor in utility economics is financing of new generating capacity. Utility financing options vary widely depending on the form of ownership, current economic conditions, the type of project being financed, and similar considerations. A summary of differences in financing by form of ownership is shown in table 12. The general considerations related to utility financing of capacity additions are reviewed here; financing considerations specific to cogeneration will be discussed in the following section.

Investor-Owned Utilities.– IOUS spend the largest proportion of funds in the electric power industry (see table 10) and, based on announced plans for capacity additions (table 13), their share of funds is likely to remain large. IOUS have four basic options for securing those funds: long-term debt, preferred stock, common stock, and retained earnings (see table 14).

The primary form of long-term debt financing for IOUS is the mortgage bond, which is secured by a conditional lien on part or all of the com-

Table 12.—Differences in Financing by Form of Ownership[a]

Ownership	Capitalization	Percent	Average return to financing sources	Tax treatment	Financiability
Federal	Debt	27.8	7.25% (1977)	Tax exempt	Federal
	Retained earnings	9.1		Taxed	revenues
	Federal	63.1			
Municipal	Debt	73	4.9	Interest on debt	Electric
	Retained earnings	25.5		exempt from taxes	revenues or
	Municipality	1.5			municipality
Cooperative:					
Distribution	Dept	66 (1977)	7.4 (1977)	Taxed	Federal loans
	Equity	34 (1977)	10.7 (1977)		or guarantees,
G&Ts[b]	Debt	96 (1977)	7.4 (1977)		or members'
	Equity	2 (1977)	10.7 (1977)		shares
Investor owned	Debt	50.3	11.85	Taxed	investors
	Preferred	12.5	9.76		
	Common	24.9	11.3		
	Retained earnings	12.3			

a1979 data unless Indicated otherwlse.
bGeneration and transmission.

SOURCE: Economlc Regulatory Adminlstration, The National Power Grid Study, Volume Il(Washlngton, D.C.: U.S. Department of Energy, DOE/ERA-0056-2, September 1979.

Table 13.–New Capacity Additions (in megawatts, net operating capacity)

	Added 1979	Planned 1980	1981	1982	After 1983	Total planned
Private	9,167	22,373	13,139	17,582	137,832	190,930
Public	2,945	17,444	26,448	1,488	20,793	26,563
Cooperative	1,640	2,675	1,543	2,577	11,376	18,171
Federal	3,323	3,315	3,322	1,891	19,376	27,904
Total	17,075	30,107	20,652	23,522	187,377	263,658

SOURCE: Office of Technology Assessment from U.S. Department of Energy data.

Table 14.—Capital Structure for Private Utiiities (average percent of capitalization)

	1966	1970	1974	1977	1978	1979	1960
Long-term debt	52.3	54.8	53.0	51.0	50.5	50.4	50.4
Preferred stock	9.5	9.8	12.2	12.5	12.4	12.5	12.3
Common stock	26.1	23.2	23.5	24.2	24,8	25.0	25.4
Retained earnings	12.1	12.2	11.3	12.3	12.3	12.1	11.9

SOURCE: Edison Electric institute, *Statistical Yearbook of the Electric Utility Industry, 1980* (Washington, D. C.: Edison Eiectric Institute, November 1981).

pany's property. In 1980, approximately 50 percent of total average IOU capitalization was long term debt. In the same year, IOUS issued around $8.3 billion in long term debt (or 58 percent of their 1980 long term financing), $7.85 billion of which was new capital and the remainder refunding. For the last quarter of 1980, the average yield on all IOU bonds was 14.11 percent, with a range of 13.18 percent for Aaa bonds to 15.20 percent for Baa bonds. For newly issued bonds, the average yield in 1980 was 13.46 percent (20).

Common stock equity represented about 25 percent of electric utilities' total outstanding capitalization in 1980. iOUs issued approximately $4.1 billion of common stock in 1980, or around 28 percent of the long term financing obtained by IOUS during that year. The average yield on common stocks during 1980 was 12.01 percent. The actual return on average common equity was 11.4 percent, while the authorized rate of return averaged around 14.2 percent (20).

Preferred stock was about 12 percent of total outstanding electric utility capitalization in 1980. In the same year, approximately $2.0 billion of preferred stock was issued by IOUS (or about 14 percent of total 1980 long-term financing), with an average yield of 12.28 percent (20).

Finally, IOUS may use internally generated capital or retained earnings to finance capacity additions. The amount of retained earnings available for financing usually is reflected by the ratio of dividends to net income, or the payout ratio. IOUS have had to pay a major portion of their net profits in dividends in recent years (75.8 percent in 1980), reducing their ability to finance projects internally. In 1980, retained earnings were the smallest source of capital available to utilities (about 12 percent of total capitalization) (20).

Publicly Owned Utilities.–Publicly owned utilities' advantages over IOUS in financing new capacity include their smaller size and thus lower capital needs, their self-regulating (in most cases) and tax-exempt status, and their absence of concern about protecting shareholders' equity. Yet this does not mean that they are totally without financing problems.

As with IOUs, the predominant form of municipal utility financing is long-term debt (73 percent of total 1979 capitalization) —mostly electric revenue bonds or general obligation bonds. Municipal bonds are attractive to investors because of their tax-free interest, but their average yield is lower as a result (4.9 percent in 1979). Equity financing for municipal utilities is a combination of direct investment by the municipal government and the retained surplus from operating revenues. The retained surplus is extremely important for municipal' ability to build a base for expansion; it averages about 10 times the amount of direct investment by the municipal government (18). In 1979, retained earnings represented an average of 25.5 percent of municipal' total capitalization (25).

The primary sources of long-term financing for cooperatives are insured loans and loan guarantees from the Rural Electrification Administration (REA). REA makes insured loans to the local distribution co-ops at interest rates of 2 to 5 percent, based on a revolving fund that has a borrowing "floor" and "ceiling" specified annually by Congress. Loans from the revolving fund are repaid from borrowers' operating revenues and from collections on outstanding REA loans (16). Since 1973, REA also has been authorized to make 100-percent loan guarantees to power supply borrowers–mostly G&Ts–for the construction and operation of powerplants and related transmission facilities. These guarantees are made almost entirely by the Federal Financing Bank, which borrows money from the U.S. Treasury. In fiscal year 1981, 34 REA loan guarantee commitments were made to power supply borrowers; they accounted for about 85 percent of REA's total fiscal year 1981 electric financing programs. Interest rates on REA loan guarantees averaged about 15 percent (45).

REA insured loans are supplemented by money raised by the National Rural Utilities Cooperative Finance Corp. (CFC) in the public bond market. Co-ops that receive REA insured loans are required to obtain from 10 to 30 percent supplemental financing from non-REA sources such as CFC (which is a giant nonprofit co-op owned by about 85 percent of the rural electric co-ops). CFC bonds accounted for approximately 4 percent of all rural electric co-op financing in fiscal year 1981 (see table 15).

Regulatory Considerations.–Almost all aspects of utility finance are regulated at either the State or Federal level or both. As in rate regulation, the States have primary jurisdiction over intrastate utility financial transactions while the Federal Government regulates interstate financing arrangements as well as those with antitrust implications.

In general, State regulation focuses on prior approval of IOU'S issuance of mortgage and debenture bonds and other long-term debts (e.g., notes over 1 year), and of common and preferred stock. Some PSCS also regulate declarations of dividends and budgets for capital expenditures. For public utilities, the authority to issue bonds derives from the State constitution or statutory authority. In many cases, a municipality must also obtain voter approval before issuing new bonds.

Table 15.—Sources of Long-Term Financing to REA Electric Borrowers (percent by fiscal year)

Year	REA 20/0	REA 5°A	REA guarantee commitments	CFC	Other financing	Total
1969	100.0%	—	—	—	—	100.0 '%0
1970	100.0	—	—		—	100.0
1971	96.6	—	—	3.4%	—	100.0
1972	72.2	—	—	15.3	12.5%	100.0
1973	32.4	52.80/o	—	13.6		100.0
1974	3.1	26.0	45.80/o	4.9	20.2%	100.0
1975	5.1	28.7	58.2	7.7	0.3	100.0
1976	10.3	24.5	57.6	5.1	2.5	100.0
TQ	7.6	22.5	64.8	3.3	1.8	100.0
1977	5.3	11.4	77.9	2.9	2.5	100,0
1978	5.1	20.8	66.2	6.0		100.0
1979	3.3	11.5	80.5	3.7	0.9	100.0
1980	2.0	11.3	81.4	4,3	0.9	100.0
1981	2.8	10.6	78.7	4.0	3.9	100.0

SOURCE: U.S. Congress, Senate hearfngs before the Commlttee on Appropiations, "Agriculture, Rural Development, and Related Agencies Appropriations," fiscal year 1980, 96th Cong., 1s1 sess., part 1—Justifications; National Rural Electric Comparative Association, personal communication to the Offlce of Technology Assessment.

Federal jurisdiction over electric utility ownership and financial operations includes regulation of debt and equity financing of holding companies and their acquisition of other entities, sales and purchases of utility property, and the issuance of securities by both the Securities and Exchange Commission (SEC) and FERC. In general, SEC regulates holding companies* under the Public Utility Holding Company Act of 1935 (PUI-ICA) in order to simplify their structures and to prevent abuses similar to those that occurred during the 1920's. SEC also regulates IOUS under the Securities and Exchange Commission Act of 1935 to protect investors and the public by providing accurate information about a wide range of factors that may affect a utility's financial position, and thus the relative risks associated with investment in its securities. Finally, under the provisions of the Federal Power Act, no utility may issue securities, or assume any financial obligation or liability (e.g., as guarantor, endorser, surety, etc.) with respect to securities, without authorization from FERC. FERC also must approve any utility sale, lease, or other disposition of property worth more than $50,000, as well as mergers or consolidations of such property, if it finds they are reasonably necessary or appropriate for the utility's corporate purposes, are in the public interest, and will not impair the utility's ability to provide service. Utilities may file the same reports on securities with both FERC and SEC in order to eliminate unnecessary paperwork.

Taxation.–Like financing, utility tax liability depends to a large extent on ownership. IOUS are fully liable for all taxes—income, excise, property, and sales as imposed by various levels of government–whereas Federal and municipal utilities usually are exempt from all tax liability. However, Federal and municipal utilities often make payments to local governments in lieu of property taxes (about 25 to 50 percent of the otherwise exempted taxes). Cooperatives generally are exempt from income and excise taxes but liable for property and sales taxes. In addition, cooperatives that derive more than 15 percent of their total revenues from nonmember services are liable for income taxes. In 1980, tax payments by IOUS averaged 12.7 percent of electric department operating revenues (20). The tax breakdown for 1980 is shown in table 16.

Taxation is primarily an issue in electric utility finance and regulation to the extent it allows special treatment that will reduce the cost of capital investments. The primary forms of special tax treatment are the investment tax credit and accelerated cost recovery coupled with special federally mandated accounting rules.

The investment tax credit (ITC) encourages investment in new, used, or leased business property that is placed in service after 1980 and that has a useful life of at least 3 years. The property must be depreciable (i.e., either tangible personal property or an improvement to real property used in qualifying manufacturing or service businesses). Buildings and real property are specifically excluded from eligibility. Since 1975, treatment of utilities under ITC provisions has been roughly equal to that of other businesses.

The amount of ITC depends on the accelerated cost recovery (ACRS) for the property. Property in the 3-year ACRS class (cars, light trucks, and research and development equipment) is eligible for a 6-percent credit, and all other property receives a 10-percent credit. There is a $125,000 limit for qualifying investments in used property from 1981 through 1984, and a $150,000 limit after 1984. If the available investment tax credit

Table 16.—Taxes Paid by Investor-Owned Electric Utilities–Electric Department Only, 1980

	Amount (millions of dollars)	Percent of operating revenue
Federal taxes:		
Income	$1,242	1.5 %
Deferred taxes on Income	1,347	1.7
Other charges In lieu of taxes[a]	1,392	1.7
Miscellaneous	1,492	1.9
Total Federal taxes charged to income	5,473	6.8
State and local taxes	4,795	5.9
Total taxes charged to income	$10,268	12.7%

[a]Includes Investment tax credits reported as charges to income for the current year.

SOURCE: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1980,* (Washington, D. C.: Edison Electric Institute, November 19s1).

*Holding companies are defined in PUHCA as those that directly or indirectly control 10 percent or more of the outstanding voting securities of a utility (or other holding company) or that, in the judgment of SEC, could exercise a controlling interest over the management or policies of a utility or holding company sufficient to make regulation necessary in the public interest.

exceeds a taxpayer's liability in any year, the excess credit may be carried forward for 15 years or backward for 3 years.

In addition to the standard ITC, an extra 10-percent credit may be available for investments in certain qualifying energy property (see table 17) through December 1982. This energy tax credit is not available on that portion of an investment which is financed by tax-exempt or other subsidized financing (e.g., industrial development bonds). Moreover, public utility property (with the exception of hydroelectric equipment) does not qualify for the energy tax credit. Other than the exceptions outlined above, the rules pertaining to the energy credit generally parallel those for the ITC.

The ITC and energy credit represent a direct reduction in tax liability (for those businesses with sufficient tax liability to benefit from it) that, in effect, reduces the cost of equipment purchases. Thus, these credits decrease the amount of investment capital needed without reducing the basis for cost recovery purposes. At present, many electric utilities have accumulated large backlogs of excess credits due to the percentage offset limitations and the accompanying carryback and carryforward provisions (see table 16). If State regulators allow utilities to retain the benefits of the ITC, they usually are used to help defray the costs of construction of new generating capacity rather than passed on to customers immediately.

Table 17.—Energy Property Eligible for ITC Under the Energy Tax Act of 1978

1. Alternative energy property:
   - boilers and burners fueled by substances other than oil/gas;
   - synthetic fuel conversion equipment;
   - equipment for converting existing oil/gas using facilities to alternate fuels;
   - equipment that uses coal as a chemical feedstock;
   - pollution control equipment for any of the above;
   - equipment for handling, preparing, storing, etc., alternate fuels for any of the above; or
   - geothermal energy facilities.
2. Solar or wind energy property used to generate electricity, to heat or cool, or to provide hot water.
3. Specially defined energy property, including:
   - recuperators,
   - heat wheels,
   - heat exchangers,
   - waste heat boilers,
   - heat pipes,
   - automatic energy control systems,
   - turbulators,
   - preheater,
   - combustible gas recovery systems,
   - economizers, or
   - other similar property defined in regulations,

   the principal purpose of which is to reduce the amount of energy used in any existing industrial or commercial process and which is installed in an existing industrial or commercial facility.
4. Equipment used to sort and prepare for recycling or to recycle solid waste.
5. Equipment for extracting oil from shale.
6. Equipment for producing natural gas from geopressurized brine.

SOURCE: Office of Technology Assessment.

The second form of tax treatment that can reduce the cost of capital investments is accelerated cost recovery. The Internal Revenue Code allows a deduction for "the exhaustion, wear and tear (including a reasonable allowance for obsolescence)" of business or investment property. Accelerated cost recovery allows property to be written off before its useful life has ended, either by shortening the useful life or by concentrating larger deductions in the early years of the asset's useful life. Under the Economic Recovery Tax Act of 1981 (ERTA), cogenerators placed in service after December 31, 1980, would be in a 5-year cost recovery class, while public utility property would be in a 5-, 10- or 15-year class, depending on its depreciation class under the previous tax laws.

In a competitive industry, much of the reduced capital cost that results from accelerated cost recovery would be passed on to customers in the form of lower prices. With regulated utilities, however, the State commissions have had to decide whether the taxes incorporated into the revenue requirement should be only those actually paid (i.e., the benefits of accelerated cost recovery are "flowed through" to customers in years of tax savings) or whether the taxes should be "normalized" over the life of the investment (i.e., the taxes included in the revenue requirement will be higher than actual taxes in the early years and lower in later years and the benefits are retained by the utility). Under ERTA, a public utility that wants to take advantage of ACRS and ITC must use normalization accounting to compute the tax expense for ratemaking purposes. If the utility uses flow-through accounting it must use the same cost recovery method for both tax and ratemaking purposes.

In 1976, accelerated cost recovery is estimated to have reduced customer rates by about $1.3 billion (2.2 percent) and utility tax payments by about $2 billion (51 percent). The ITC reduced rates to a much smaller extent (perhaps $200 million), but decreased utility taxes by $1.3 billion. The combined effect was a 2.6-percent reduction in customer billings, an 84-percent decrease in Federal tax payments by utilities, and a 20-percent ($2 billion) increase in the cash flows of normalizing utilities. In 1979, it is estimated that tax incentives provided IOUS with $3 billion per year additional construction funds (equivalent to 15 percent of annual construction expenditures). In some cases, these tax incentives may represent the only source of internal funds for utilities (15).

Other provisions of Federal tax law that provide investment incentives for utilities include a deduction for interest paid to bondholders that reduces the cost of debt financing; a deduction for IOUS of about 30 percent of the dividends paid on preferred stock; and, a deduction for the costs of repairs or improvements to depreciable property based on a specified annual percentage of the property's cost.

REGULATION OF SERVICE AND OPERATIONS

The third major area of electric utility regulation is State and Federal jurisdiction over utility service and operations. The primary concerns of such regulation are to ensure adequate service, to protect the public health and welfare, and to further national policy goals related to fuel use.

Service Regulation.– State PSCS have broad authority over utility services, including granting the right to serve, defining service territories, and approving major capacity additions. The primary mechanism by which a PSC exerts control over these activities is the certificate of public convenience and necessity, which essentially is a permit to operate a utility. In addition, many PSCS also have jurisdiction over the operating characteristics of private (and some public) utilities, including authorizing or requiring interconnections, requiring utilities to operate as common carriers, ordering the joint use of facilities among two or more utilities, and requiring line extensions within a utility's service territory (see table 18).

The Federal Government's primary role in regulating utility service is through its authority over interconnection and coordination among utilities. Under section 202(a) of the Federal Power Act of 1935, FERC (formerly FPC) was directed to

Table 18.—State Regulation of Utiiity Service and Operations

Authority	Number of PSCS according to type of utility regulated[a]: Investor-owned	Public	Co-op
Certificate of convenience and necessity required for:			
Generating capacity additions	25	9	15
Transmission line additions	28	14	20
Distribution system additions	20	11	13
Other plant additions	16	8	11
Initiating service	31	13	20
Abandoning facilities or service	34	17	21
Regulate State exports	6	2	3
Allocate unincorporated territory among utilities	33	14	22
Establish standards for:			
Voltage levels	41	17	24
Safetv	44	21	26

[a]Includes 50 State commissions plus District of Columbia, Puerto Rico, and Virgin Islands.

SOURCE: Alan E. Finder, *The States and Electric Utility Regulation* (Lexington, Ky.: The Council of State Governments, 1977).

"divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy" in order to ensure an abundant supply of electricity throughout the United States "with the greatest possible economy and with regard to the proper utilization and conservation of natural resources." Once these districts were established, the Federal Government's role was limited to promoting and encouraging voluntary interconnection and coordination of facilities within and among them.

PURPA expanded FERC'S authority in regard to interconnection and coordination in a number of ways. Section 205(a) of PURPA authorizes FERC (either on its own motion or upon receipt of an application) to exempt a utility from State laws, rules, or regulations that prohibit or prevent voluntary coordination, including agreements for central dispatch, if the coordination is designed to obtain the economic utilization of facilities and resources in any area. Section 205(b) directs FERC to study the opportunities for energy conservation, increased reliability, and greater efficiency in the use of facilities and resources through pooling arrangements. Where such opportunities exist, FERC may recommend to utilities that they voluntarily enter into negotiations for pooling. Finally, PURPA expanded FERC'S authority to order interconnections to include those with qualifying cogeneration and small power production facilities, and to include wheeling orders. These provisions are discussed in detail in the next section.

Public Health and Welfare.–Regulation of utility operations in the interests of protecting the public health and welfare focuses on safety standards and on environmental protection. At the State level, the primary responsibilities include the implementation of federally mandated programs as well as the establishment and enforcement of minimum standards for voltage, metering accuracy, customer and employee safety, and emergency situations and curtailments.

Such Federal legislation affects powerplant siting and operation substantially through requirements for environmental impact assessments and pollution monitoring and control, as well as through provisions that limit the available sites for large generating facilities. The most important Federal programs in this area include:

- *The National Environmental Policy Act of 7969* (NEPA), which requires all Federal agencies to include a detailed environmental impact statement on every major Federal action significantly affecting the quality of the human environment.
- *The C/can Air Act* sets National Ambient Air Quality Standards that are implemented through standards of performance for new stationary sources and guidelines for State control strategies for existing sources, and through guidelines for regulatory programs designed to improve air quality in non-attainment areas and to prevent degradation of air quality in clean air areas.
- *The Clean Water Act* imposes effluent limitations on quantities, rates, and concentrations of chemical, physical, biological, and other constituents discharged into navigable waters, and are implemented through ambient water quality standards, effluent standards for new and existing sources, standards for thermal discharges, and permit programs.
- *The Resource Conservation and Recovery Act of 1976* seeks to control the land disposal of solid wastes (e.g., fly and bottom ash, scrubber sludge) through a system of State plans and permits for solid waste disposal.
- *The Atomic Energy Act,* which includes comprehensive licensing and permitting procedures for both the construction and operation of nuclear powerplants.
- *The Occupational Safety and Health Act (OSHAJ* which establishes standards for the protection of workers, requires recordkeeping, and sets up a process for periodic inspections and the filing of complaints.
- *The Endangered Species Act of 1973,* which requires that all Federal departments and agencies consult with the Secretary of the interior to ensure that actions authorized, funded, or carried out by them do not jeopardize the continued existence of these species or result in the destruction or adverse modification of their habitat.
- *The National Historic Preservation Act of 1970* which requires all Federal agencies to

determine whether a proposed action will affect a site or structure listed or eligible for listing in the National Register and, if so, to obtain comments from the Advisory Council on Historic Preservation.

- *The Fish and Wildlife Coordination Act of 1970,* under which Federal agencies must consult with the Department of the Interior's Fish and Wildlife Service and with the State agency having jurisdiction over fish and wildlife prior to taking any action potentially affecting surface waters.
- *Army Corps of Engineers requirements* that all projects affecting navigable waters obtain a permit from the Corps.
- *The Coastal Zone Management Act,* which requires Federal agencies to obtain certification that proposed actions are consistent with approved State programs.

Although this list of Federal programs is not all-inclusive, it offers a general idea of the scope of laws and regulations that affect the siting, construction, and operation of central station generating plants. These regulations can lengthen the leadtime for siting and building a powerplant, require technological and other environmental controls in plant design and operation, and impose significant monitoring and recordkeeping requirements during plant construction and operation, all of which increase the direct costs of electricity generation.

Regulation of Fuel Use.–Prior to 1973, the choice of fuel for utility and industrial plants was primarily a matter of resource availability, economics, and convenience, as influenced by indirect regulation through tax and environmental laws, and price controls. Then, natural gas shortages and the 1973 oil embargo drastically changed the economic and supply considerations of fuel use and introduced direct Federal regulation. The primary Federal regulations on fuel use that affect utilities derive from the Fuel Use Act (FUA) and the Natural Gas Policy Act (NGPA), both part of the National Energy Act of 1978.

The primary purpose of FUA is to encourage greater use of coal and other alternate fuels as the primary energy source in utility, industrial, and commercial generation of electricity or thermal energy, and thus to conserve oil and gas for other uses. To achieve these purposes, FUA prohibits the use of natural gas or petroleum as a primary energy source in new electric powerplants and new major fuel-burning installations* and provides that no new electric powerplants may be constructed without the capability to use coal or any other alternate fuel as a primary energy source. FUA also prohibits existing powerplants from using natural gas as their primary energy source after 1990 and, in the meantime, from switching from any other fuel to natural gas or from increasing the proportion of natural gas used as the primary energy source. Moreover, the Secretary of Energy can issue prohibition orders for the involuntary conversion of existing powerplants to coal or another alternate fuel if the owner or operator of the powerplant commences the proceeding by filing an affirmative certification that the plant has the technical capability to use coal or another alternate fuel, or could have that capability without substantial physical modification or reduction in rated capacity, and it is financially feasible for the facility to use coal or other non-premium fuels.

Through December 1980, FUA prohibition orders had been issued for 53 oil burning units–mostly powerplants—and another 13 units were undergoing voluntary conversion to coal. In addition, 33 powerplants and 15 major fuel-burning installations (MFBIs) are subject to outstanding conversion orders under an earlier law (the Energy Supply and Environmental Coordination Act of 1974). Together, these 114 units have the potential to displace around 400,000 barrels (bbl) of oil per day (19).

FUA prohibitions are subject to a wide range of temporary and permanent exemptions. The temporary exemptions are granted for a period of 5 years; some of these can be extended to a total of 10 years but in no case beyond December 31, 1994. The most widely used of these exemptions is a special public interest exemption for the temporary use of natural gas in existing power-

*The provisions of FUA apply to powerplants and other stationary units that have the design capability to consume any fuel at a heat input rate of at least 100 MMBtu/hr or to a unit at a site that has an aggregate heat input rate of at least 250 MMBtu/hr.

plants that would otherwise burn middle distillates or residual fuel oils. The 1,058 petitions for this exemption that have been granted or are in process have the potential to displace 83,523 bbl/day middle distillate, 323,825 bbl/day residual fuel oil with a sulfur content of 0.5 percent or less, and 236,950 bbl/day residual with greater than 0.5 percent sulfur (or a total of 644,298 bbl/day) (19).

The actual effect of FUA on fuel use in existing and new powerplants and MFBIs is difficult to determine without a case-by-case analysis. The considerations imposed by the act must be viewed in the context of economic, technical, and managerial concerns. Absent a FUA prohibition order or exemption request, it is not always possible to identify the determining factor in electric utilities' fuel choice. Many energy analysts argue that it became cheaper to convert existing oil-fired plants to coal or to replace them with new coal or nuclear plants when the price of residual fuel oil reached $30 to $40/bbl (2,46). However, the economics of displacing existing oil-fired capacity may be outweighed by utilities' financial problems and the costs of using alternate fuels. Thus, fully two-thirds of the capacity that is economically feasible to convert has yet to be converted. Moreover, of the 66 units being converted under FUA, only 13 are doing so voluntarily (i.e., without a prohibition order), and those 13 represent only about 4 percent of the total potential oil displacement in the 66 units (19).

NGPA was designed to increase energy supplies while reducing domestic consumption. In general, the act distinguishes among a number of different classes and categories of natural gas according to the date the gas is committed to interstate commerce, whether the well is onshore or offshore, and the depth and location of the reservoir. Varying price schedules that would eventually lead to decontrol are established for the different classes and categories. These schedules are supplemented with rules for allocation and pricing of gas to final consumers. Residential customers generally have first priority for supplies under contract to interstate pipelines, with any remaining supplies spread through various lower priority commercial and industrial customers. There are complicated resale price schedules for all customer classes, with the highest priority generally being given the lowest of all outstanding prices.

NGPA assigns the lowest priority industrial gas users an incremental price equal to the new gas wellhead price plus regulated pipeline transportation margins. This higher incremental price is mitigated through a ceiling determined by the alternative fuel oil price. In some areas, the ceiling is based on number two distillate fuel and in others on residual fuel. Several users that otherwise would be subject to the higher incremental prices are specifically exempted, including small industrial boilers (using less than an average of 300 MCF/day); agricultural uses for which alternative fuels are not economic or available; schools, hospitals, and other institutions; electric utilities; and qualifying cogeneration facilities under section 201 of PURPA.

Current Status of Electric Utilities

Economic, energy, and utility analysts agree unanimously that the electric power industry—particularly the investor-owned portion-is in trouble due to its deteriorating financial condition (34,64). The symptoms are abundant, including declining real returns on equity and interest coverage, increased capital spending and debt/equity financing combined with high dividends per share, high payout ratios, and low market-to-book values. This situation represents a somewhat abrupt turnaround in the industry's financial health. During the two decades from 1945 to 1965, utilities accommodated rapid demand growth while continually lowering prices by taking advantage of economies of scale in generation as well as greater efficiency in transmission and distribution. Capital expenditures remained relatively constant on a per-customer basis and utility costs actually declined in some years although prices within the economy in general were rising. Return on equity rose steadily, most utilities had high bond ratings, and the market-to-book ratio more than doubled. Moreover, during those two decades energy consumption in general moved in line with other economic activity as electricity demand grew at roughly twice the rate of the economy and far faster than energy usage as a whole. The price of electricity declined on an absolute basis as well as relative to prices as a whole and to the price of competing fuels (34).

However, 1965 is considered the watershed year for the electric utility industry. In that year, stock prices, rate reductions, and interest coverage ratios peaked, while a number of events reshaped utility capital investment such that money spent would not necessarily lead to reduced costs. For example, the Northeast blackout required expenditures to improve reliability of service, but those expenditures would neither reduce costs nor automatically be associated with increased revenues. Similarly, the environmental movement required capital expenditures that did not make plants more efficient or increase capacity. The military buildup in Vietnam signaled the onset of high inflation rates and brought construction delays and labor productivity problems. Emerging natural gas shortages caused utilities to shift to more capital-intensive types of powerplants, including coal and nuclear fueled plants, that took longer to build, cost more, and operated less efficiently (34).

As a result, capital spending accelerated, rate base increased more rapidly than sales, and a larger percentage of financing requirements had to be met through new capital (i.e., sales of securities). The combination of rising interest rates, an increasing amount of debt, and relatively slow growth in income resulted in decreasing interest coverage ratios and a decline in the quality of utility debt, and thus even higher interest rates. The combination of higher interest rates and lower return on equity pushed stock prices down until they fell well below book values. The average market-to-book ratio went from an all-time high of 2.35 in 1965 to a low of 0.67 in 1974, and back up to 0.80 in 1978. Thus, during a period when securities were claiming an ever larger share of total capitalization, each new issue further diluted the interests of shareholders. At the same time, utilities began to capitalize an allowance for funds used during construction (AFUDC) in their income statements, which increased the non-cash portion of their reported earnings. Therefore the overall decline in return on equity was greater than was apparent from the reported figures. The only available solution to the problem was to increase rates (34).

in 1970, the average price of residential electricity increased for the first time in 25 years, and has continued to rise ever since from its low of $.0209/kWh in 1969 to its high in 1980 of $.0493 /kWh ($.0536/kWh for IOUS). * The average price of all electricity also has risen–from a low of $.0154/kWh in 1969 to a high of $.0437/kWh in 1980 (4.72 WkWh for IOUS) (20). However, the rate relief obtained in the last 10 years has been inadequate to raise interest coverage and return on equity to their previous levels and bond ratings have fallen, increasing interest charges still further. Moreover, although the price of electricity did not increase as rapidly as those of competing fuels, it did go up more than prices as a whole throughout the economy.

The electric power industry's problems up until the early 1970's were compounded by other factors during the last decade. First, the 1973-74 oil embargo drastically changed both fuel supplies and prices, and utility customers cut back on electricity consumption. In 1974, electric usage per customer decreased for the first time since 1946, and the previously steady pattern of rapid growth (about 8 percent per year from 1947 to 1972) changed dramatically.** But the industry had geared its capital spending and its expense budget to the previous sales gains. Capacity additions begun before 1974 became excess capacity as these gains failed to materialize. Moreover, much of the new capacity installed or announced in the years immediately preceding the embargo was oil-fired in response to environmental objections to coal and to uncertainties in natural gas supplies. This decline in demand growth caught utilities in a squeeze between high fixed costs and declining base rate revenue due to falling sales (34).

A second factor that dramatically affected utility fortunes during the 1970's was one utility's omission of a common stock dividend—a first for the utility industry-in April 1974. In that month, the

*Prices expressed in current dollars.

**While electricity demand growth has slowed noticeably, since 1973 it still has been about twice that of energy as a whole.

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utility stock average fell 18 percent, and by September had fallen 36 percent, the largest drop in any calendar year since 1937. Also, 1974 was the year that market-to-book ratios hit their low of 0.67. The increased risk in utility stocks carried over to the market in lower quality bonds, and for the first time, investors had to consider the possibility of a financial risk in utility securities, and utilities had to face the prospects of even higher costs for new capital (34).

A third major event affecting the electric power industry during the 1970's was the accident at the Three Mile Island (TMI) nuclear powerplant in 1979. Even before TMI, some investors had been leery of nuclear-oriented utilities because of the huge sums involved in one project that could be delayed or halted by a determined opposition. The TMI accident added another risk–if an operating nuclear plant went out of service, the power company might have to purchase far more expensive electricity from other utilities. If the regulators did not allow the purchased power costs to be passed on to consumers, the utility could suffer serious financial losses. General Public Utilities, whose subsidiaries owned TMI, was forced to omit its dividend and was unable to place securities in the public market after the accident. In conjunction with a weakened financial state and excess generating capacity in many areas, the accident accelerated the cancellation or deferral of nuclear projects by many electric utilities (34).

Based on some indicators, the general economic and financial deterioration of the electric power industry that began in the late 1960's and continued through the 197o's seems to have begun to turn around. Electric utility earnings began to rise sharply in late 1980 and continued to increase through 1981. The gain in earnings lifted the average return on equity (for a sample of 85 electric utilities representing 95 percent of IOU revenue) to 12.3 percent by September 1981 —the highest return earned since the late 1960's. The proportion of capital spending financed with internally generated funds (including common equity) rose with the return on equity, reaching 43 percent late in 1981, entirely offsetting the decline that occurred during 1979 and early 1980 (63).

However, other indicators are not so favorable. Even though the earned rate of return has increased steadily in the last 2 years, it still lags behind the authorized return–estimated to be about 14.2 percent in 1980. In addition, although operating revenues have risen (by 18.3 percent in 1980) due to a combination of increases in rates, fuel adjustment clauses, and sales to ultimate customers, the gains in revenues were more than offset by increased operating expenses (up 19 percent in 1980), primarily due to higher fuel costs (20). Similarly, the increased percentage of equity financing has not been sufficient to offset the record high interest rates. Utility interest expenses have continued to rise at more than 20 percent annually while interest coverage ratios (the ratio of net income and income taxes to interest expense) have remained relatively static for the last 2 years. In late 1981, the average interest coverage ratio was 2.47 with AFUDC, and 2.01 without AFUDC. Common stock dividend payout ratios have risen steadily, to a record 75.8 percent in 1980 (compared to a traditional IOU payout ratio of 65 to 68 percent). Finally, sales of stock have continued to dilute the book value at a rate that more than offsets the contribution of retained earnings (63).

As long as interest rates remain high and earned returns on equity remain lower than authorized, utilities will continue to have trouble regaining their financial health. Without additional aggressive rate relief, growth in earnings is likely to continue to lag behind that of revenues. The high interest rates would continue to favor equity financing over long-term debt, and thus continue to erode book value and increase payout ratios to the detriment of stockholders' interests. As a result, IOUS are likely to continue having trouble financing their construction budget.

Possibie Future Paths for the Electric Power industry

A wide range of options are available to utility planners today, perhaps wider than at any time in the past. The menu of generating and other technologies from which to choose, the array of institutional arrangements for financing and management, the possibilities for investment on the customer's side of the meter—all have expanded greatly in recent years. All of these options must be considered in the context of their potential to reduce utility dependence on oil and reduce capital expenditures and operating costs, while enabling utilities to continue to provide reliable service and protect investors.

Given the numerous unpredictable events that have plagued the electric power industry over the last 15 years, utilities will have to develop plans with sufficient flexibility to handle a wide array of contingencies in demand growth, technology availability, and economic conditions. In many cases, these plans will be substantially different in character from traditional planning, either due to their approach to the size and mix of generating technologies, or through planned controls on the rate or type of demand growth.

One possible way to achieve such flexibility is for a utility to diversify its energy mix. Thus, rather than being heavily dependent on any one fuel (e.g., coal, nuclear), the utility's capacity would be spread among the available options, reducing the risk of a capacity shortfall in the event of unexpected fuel shortages (e.g., a coal strike, a nuclear accident). Second, utilities will have to plan for financing flexibility. Conventional large baseload plants are extremely capital intensive. Because of their size, they often lead to short-term excess capacity until sales have a chance to grow sufficiently to match the increased capacity. In addition, their long construction lead-times often mean high interest charges. As was seen in the previous section, unless these large baseload plants substantially increase system efficiency and reduce utility costs, they can contribute significantly to financial deterioration. Smaller capacity increments, on the other hand, are easier to phase in as demand develops, and allow greater short-term financing flexibility. In this sense, the smaller additions substitute financial optimization in planning for the engineering optimization achieved in large conventional plants.

A third option for utility planners is to invest in energy and fuel efficiency at the point of use. As was seen in the discussion of the current status of electric utilities above, one of the factors that contributed to current utility financial problems was utilities' need to make capital investments (e.g., for environmental protection, increased system reliability) that neither reduced costs nor served new customers. Thus, overall system productivity declined as costs increased. In order to reverse this trend, some utilities are planning to invest heavily in technologies that contribute to system efficiency (e.g., conservation, load management) in lieu of new capacity.

Beyond these three major options, there are several other steps a utility can take to improve its financial position with regard to meeting future service needs. For example, joint action agencies (see discussion of utility organizations, above) allow a utility to benefit from economies of scale while also receiving the advantages of investment in small capacity increments, including financial and planning flexibility. In some areas, conversion to public ownership may be an option for improving utilities' financial status, since publicly owned utilities have access to lower cost capital and do not need to be concerned with protecting stockholders' interests.

However, utilities' system and financial planning is only one aspect of the future of the electric power industry. Without appropriate regulation, many of the options discussed above will not be feasible and even well-managed utilities could face financial and service dilemmas.

Utility regulators at all levels of government also have a wider range of options than has existed in the past. The problems faced by electric utilities have led to a better understanding of utility economics and its regulatory implications. The result has been a wide range of regulatory innovations that could complement utility planning for flexibility. But if regulators fail to take advantage of such options, or to ensure that utilities are compensated adequately for the increased risks they will be facing, even the most innovative utility planning will be to no avail.

REGULATION AND FINANCING OF COGENERATION

Historically, cogenerators faced three major institutional obstacles when seeking interconnected operation with an electric utility. First, utilities often were reluctant to purchase cogenerated electricity at a rate that made interconnected cogeneration economically feasible. Second, some utilities charged very high rates for providing backup service to cogenerators. Third, a cogenerator that sold electricity risked being classified as—and therefore being regulated under State and Federal law as–an electric utility. As a result of these and other disincentives, cogeneration was not able to compete, except in large stand-alone industrial applications, with electricity generated in central station powerplants plus thermal energy from conventional combustion systems.

In recent years, however, cogeneration has attracted a lot of attention as a means of increasing energy efficiency, easing utilities' financial stress, and reducing the amount of oil needed to supply electric and thermal power to buildings and industries. Where these benefits are available (see chs. 5 and 6), recent changes in Federal and State regulation and in financing practices may improve cogeneration's ability to compete with conventional energy conversion systems. This section describes the regulatory and financing considerations that may affect utility, industrial, or commercial firms' decisions to install cogeneration capacity.

Federal and State Regulation

A number of recent legislative initiatives are intended to clarify the role of cogeneration within national energy and environmental policy, and to encourage its use under those circumstances where it would save fuel or allow increased efficiency in electric utilities' use of facilities and resources. The most significant of these initiatives include PURPA which provides guidelines for relations among cogenerators, utilities, and regulators; other parts of the National Energy Act that address the use and cost of premium fuels; and provisions of various environmental regulations that have been adapted to cogeneration's special problems and opportunities.

The Public Utility Regulatory Policies Act

Title Ii of PURPA was designed to remove the three obstacles to interconnected cogeneration listed above. Under section 210 of PURPA, utilities are required to purchase electricity from, and provide backup service to, cogenerators (and small power producers) at rates that are just and reasonable, that are in the public interest, and that do not discriminate against cogenerators. Section 210 also allows FERC to exempt cogenerators from state regulation of utility rates and financial organization, and from Federal regulation under the Federal Power Act and PUHCA. Electric utilities also are required to interconnect with qualifying facilities and must offer to operate in parallel with them. In order to qualify for these and other benefits available under PURPA, cogenerators must meet the requirements of section 201 for operating characteristics, fuel use, and ownership.

At this time, the fate of the PURPA provisions is unclear. In January 1982, the U.S. Court of Appeals for the District of Columbia Circuit ruled that portions of the FERC regulations implementing PURPA were invalid. Specifically, the appeals court vacated the FERC rules on rates for utility purchases of cogenerated power, and on interconnections between utilities and cogenerators, but upheld the FERC regulations on fuel use and on simultaneous purchase and sale (1). The Supreme Court has agreed to review the appeals court decision.

As a result of this pending case, it is not possible to say definitively what is the Federal policy on cogeneration. Therefore this section will outline the statutory provisions of PURPA and the FERC rules implementing those provisions, and will review the relevant court rulings and their effect on PURPA'S implementation.

REQUIREMENTS FOR QUALIFICATION

The benefits of PURPA are afforded only to "qualifying facilities." Section 201 defines a qualifying cogeneration facility as one that produces electricity and steam or other forms of useful thermal energy for industrial, commercial, heating, or cooling purposes; that meets the operating requirements prescribed by FERC (such as requirements respecting minimum size, fuel use, and fuel efficiency); and that is owned by a person not primarily engaged in the generation or sale of electric power (other than cogenerated power).

Ownership Criteria.–The conference report on PURPA makes it clear that Congress did not intend to preclude electric utilities altogether from participation in qualifying facilities (14). Thus, either directly or through a subsidiary company, an electric utility can participate in the ownership of a qualifying cogenerator. Rather, the thrust of the ownership requirement is to limit the advantages of qualifying status to cogenerators that are not owned primarily by electric utilities or their subsidiaries. Under the FERC rules implementing section 201, the legal test is whether more than 50 percent of the entity that owns the facility is comprised of electric utilities or public utility holding companies (70). This ownership limitation does not apply to gas or other utilities.

Efficiency and Operating Standards.–The FERC regulations require topping cycle cogeneration facilities to meet both operating and efficiency standards. Because "token" topping cycle facilities could produce "trivial amounts of either useful heat or power," an operating standard was established to distinguish bona fide cogenerators from essentially single purpose facilities. This standard specifies that at least 5 percent of a topping cycle cogenerator's total energy output (on an annual basis) must be useful thermal energy (69). There is no operating standard for bottoming cycle plants because they produce electricity from otherwise wasted heat, and thus do not have the same potential for "token" production.

The topping cycle efficiency standard is designed to ensure that an oil- or natural gas-fired cogenerator will use these fuels more efficiently than any combination of separately generated electric and thermal energy using efficient state-of-the-art technology (e.g., a 8,500-Btu/kWh combined-cycle generating station and a 90-percent efficient process steam boiler). The efficiency standard established by FERC specifies that, for topping cycle cogenerators: 1) for which any of the energy input is oil or natural gas; and 2) for which installation began on or after March 13, 1980, the useful electric power output plus one-half the useful thermal energy produced must be, during any calendar year, no less than 42.5 percent of the energy input of oil and natural gas. However, if the useful thermal energy output is less than 15 percent of the total energy production, the useful electricity output plus one-half the useful thermal energy production must be no less than 45 percent of the total oil or gas input. Topping cycle cogenerators that were installed prior to March 13, 1980, and those that use fuels other than oil and gas do not have to meet any efficiency standards in order to qualify under PURPA (69).

The 2-to-1 weighting in favor of electricity production in these topping cycle efficiency standards reflects FERC'S view that "systems with high electricity to heat ratios have the highest second-law' energy efficiencies," and their development and use should be encouraged (see discussion of the thermodynamic efficiency of cogenerators in ch. 4) (76). This weighting will be more equitable to the various cogeneration technologies than a standard that simply summed electric and thermal output on an equal basis, because the latter would have made it relatively easy for steam turbines that produce little electricity to qualify, but would have penalized higher E/S ratio systems through difficult heat recovery requirements.

Because bottoming cycle facilities produce electricity from normally wasted heat, the efficiency standard only applies to those with supplementary firing heat inputs from oil and natural gas. In such facilities, the useful output of the bottoming cycle must, during any calendar year, be no less than 45 percent of the energy input of natural gas or oil for supplementary firing (i.e., the fuels used in the thermal process "upstream" from the facility's power production system are not considered in the efficiency test) (69).

Environmental Criteria.– FERC'S original requirements for qualification under PURPA denied qualifying status to diesel and dual fuel cogenerators built after March 13, 1980, pending environmental review. FERC'S final environmental impact statement (FEIS), released in April 1981, acknowledged that "an increase in the number of diesel and dual-fuel cogeneration facilities in an air regime may cause significant environmental effects in the near term." But the FEIS concluded that existing State and local air quality monitoring and permit programs would be adequate to prevent such effects, and "unregulated proliferation of diesel and dual-fuel cogenerators is not a realistic scenario." Based on these conclusions, FERC has declared diesel and dual-fuel cogenerators eligible for PURPA benefits (28).

Fuel Use Limitations.—Section 201 of PURPA specifies that a qualifying cogeneration facility must meet "such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe." In implementing this section, FERC interpreted the statutory language as discretionary and chose not to impose fuel use limitations on qualifying cogenerators. FERC offered four arguments to support their position that this decision was consistent with congressional intent and national energy policy. First, FERC reasoned that if Congress had intended to deny qualifying status to oil- and gas-fueled cogenerators, PURPA would have contained explicit restrictions on fuel use similar to those that apply to small power producers. Second, Congress did include fuel use restrictions on oil- and gas-fired cogenerators in FUA, which was enacted at the same time as PURPA. Therefore, FERC determined it would be both unnecessary and inappropriate to impose an additional set of fuel use regulations under PURPA. Third, FERC argued that Congress recognized that qualifying cogenerators would burn natural gas by expressly exempting such facilities from the incremental pricing program under NGPA (enacted at the same time as PURPA). Fourth, FERC noted that the findings in section 2 of PURPA require "a program providing for . . . increased efficiency in the use of facilities and resources." Thus, the commission argued that oil and gas burning cogenerators should be granted qualifying status to the extent that they provide for more efficient use of these resources, and the efficiency standards discussed above would be sufficient to ensure such use (76).

FERC'S decision was upheld by the U.S. Court of Appeals, which agreed with these four arguments and held that the statutory language is discretionary and that the regulations promulgated by FERC were a reasoned and adequate response to the congressional mandate.

UTILITY OBLIGATIONS TO QUALIFYING FACILITIES

Under section 210 of PURPA and the FERC regulations implementing that section, electric utilities have a number of obligations to qualifying cogenerators. These include the requirement that utilities offer to purchase power from and sell power to cogenerators at equitable rates (including simultaneous purchase and sale), that they offer to operate in parallel with cogenerators, and that they interconnect with cogenerators.

Obligation to Purchase.–Section 210 of PURPA requires FERC to establish "such rules as it determines necessary to encourage cogeneration," including rules that require electric utilities to offer to purchase electric power from cogenerators. FERC interprets this provision as imposing on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities (QFs) with which the electric utility is directly or indirectly interconnected, except during system emergencies or during "light loading periods" (see below) (75).

PURPA specifies that purchase power rates must be just and reasonable to the electric utilities' consumers and in the public interest, and must not exceed the incremental cost to the utility of alternative electric energy. The FERC regulations use the term "avoided costs" to represent these incremental costs, and define them as:

> The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, such utility would generate itself or purchase from another source *(68).*

The energy costs referred to in this definition are the variable costs associated with the production of electricity, and include the cost of fuel and some operating and maintenance expenses (see discussion of rate structures in the previous section). Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of generating and other facilities (75). Thus, if by purchasing electricity from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for the purchase from the QF must be based on those energy costs that the utility can thereby avoid. Similarly, if a QF offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing utility to build a smaller less expensive plant, avoid the need to construct a generating unit, or reduce firm power purchases from the grid, then the purchase rates must be based on both the avoided capacity and energy costs (75). In each case, it is the incremental costs, and not the average or embedded system costs, that are used to determine avoided costs.

One way of figuring the avoided cost is to calculate the difference between: 1) the total capacity and energy costs that would be incurred by a utility to meet a specified demand, and 2) the cost the utility would incur if it purchased energy or capacity or both from a QF to meet part of its demand and supplied its remaining needs from its own facilities. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan excluding the QF, over the same total capacity and energy cost of the system including the QF (75). The FERC rules require utilities to furnish data concerning present and anticipated future system costs of energy and capacity to enable potential cogenerators to estimate avoided costs.

The FERC rules outlined three primary considerations in determining avoided costs. The first is the availability of capacity or energy from a QF during system daily and seasonal peakloads. If a QF can provide electricity during peak periods when the utility is running its most expensive generating units, the electricity from the QF will have a higher value to the utility than power supplied during off-peak periods when only lower cost units are running. The relevant factors in determining the QF's availability include:

- *The utility's ability to dispatch the cogenerator* will enhance its ability to respond to changes in demand and thereby enhance the value of the cogenerated power (see discussion of interconnection in ch. 4).
- *The expected or demonstrated reliability of the cogenerator* (i.e., whether it may go out of service during the period when the utility needs its power to meet system demand) will determine whether the utility can avoid the construction or purchase of alternative capacity.
- *The terms of any contractor* other legally enforceable obligation (including its duration, termination notice requirements, and sanctions for noncompliance) also will provide a measure of the QF's reliability.
- *If maintenance of the QF can be scheduled* during the periods of low demand on the utility system or during periods when the utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of capacity on peak.
- *If the QF can provide capacity and energy during system emergencies,* and can separate its load from its generation during such an emergency, it may increase overall system reliability and thereby enhance the value of the cogenerated power.
- *The aggregate or collective value of capacity* from a number of small QFs may be sufficient to enable a purchasing utility to defer or avoid scheduled capacity additions when none of the QFs alone would provide the equivalent of firm power to the utility.
- *The leadtimes associated with capacity additions from QFs* maybe less than the leadtime required for a utility powerplant, and thus the QF might provide savings in the utility's total power production costs by permitting utilities to avoid the excess capacity associated with adding large generating units or by providing greater flexibility in accommodating changes in demand (see ch. 6) *(72).*

The second consideration in a State regulatory commission's determination of avoided costs under the FERC rules is the relationship of energy or capacity from a QF to the purchasing utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add new capacity, then the availability of capacity from a cogenerator will not immediately enable the utility to avoid any capacity costs. However, a utility with excess capacity may plan to build new plants in order to increase system efficiency or reduce oil and gas use. If purchases from a QF allow the utility to defer or avoid these capacity additions, the rate for such purchases should reflect these avoided capacity costs as adjusted for the lower energy costs the utility would have incurred if it had added the new capacity (75), That is, if deferring new construction may actually increase power costs, the qualifying facility may be credited only with the net of the deferred and increased costs.

Third, the utilities and State commissions must take into account any costs or savings from transmission line losses. Power produced by a QF maybe nearer to or farther from the service area than the utility-generated power it supplants. Because all power is subject to transmission losses as a function of distance, the rate for energy provided by the QF is to be net of line losses or gains.

In general, avoided costs are determined on a case-by-case basis. However, for small QFs, individualized rates may have very high transaction costs. Therefore, the FERC rules require utilities to implement standardized tariffs for facilities of 100-kW electrical capacity or less, and permit the use of such tariffs for larger units. These tariffs must be based on the purchasing utility's avoided cost, as described above, but may differentiate among QFs on the basis of the supply characteristics of the particular technology (72).

The net avoided cost concept leads to the possibility that, despite their inherent efficiencies, QFs may at times produce power that is more expensive than power produced by the utility (e.g., when the utility is under a low load situation and operating only baseload plants). Thus, if the utility has to reduce its baseload plant output in order to accommodate power purchases from a QF, it may also have to utilize higher cost peaking units when load increases or supplies from qualifying facilities drop, due to the longer startup times of baseload plants. A strict application of the avoided cost rules under such circumstances would mean a negative avoided cost that would have to be reimbursed by the QF. To avoid the anomalous result of forcing a cogenerator to pay a utility for purchasing cogenerated power, the FERC rules provide that an electric utility is not required to purchase power from a QF when such a purchase would result in net increased operating costs to the utility. A utility that wants to cease purchasing from a QF due to these operational circumstances must notify each affected QF in time for the QF to stop delivering energy or capacity. If the utility fails to provide adequate notice of a light loading period, it must reimburse the QF for energy and/or capacity as if the light loading had not occurred. The existence of a light loading period is subject to verification by the PSC (75).

The FERC rules for purchase power rates do not preclude negotiated agreements between cogenerators and electric utilities on terms that differ from the PURPA provisions. However, a QF that needs a long-term contract to provide certainty in return on investment can still obtain a purchase rate based on the utility's avoided costs, either by establishing a fixed contract price for energy and capacity at the avoided costs at the time of the contract or arranging to receive the avoided costs determined at the time of power delivery (75).

Finally, the FERC rules do not preclude States enacting laws or regulations that provide for purchase power rates that are higher than those that would obtain under PURPA. However, the States cannot require rates at less than full avoided costs because such lower rates would fail to provide the requisite encouragement to cogeneration and small power production (75).

As mentioned previously, the FERC rules for purchase power rates were challenged by the American Electric Power Service Corp. (AEP) and several other electric utilities, who argued that FERC'S requirement that purchase power rates equal the utility's full avoided costs forecloses the sharing of any of the benefits of the purchase with the utility's other customers, and thus contravenes the PURPA section 210 requirement that such rates be "just and reasonable to the electric consumers of the electric utility and in the public interest." The U.S. Court of Appeals for the District of Columbia Circuit held that Congress, in the statute, had clearly distinguished between a "just and reasonable" rate and one based on the full avoided cost, and that, although "the two may coincide," FERC had not adequately justified its adoption of a uniform full avoided cost standard (1).

In the preamble to its final rule on purchase power rates, FERC states that:

> The Commission interprets its mandate under section 21 O(a) to prescribe "such rules as it determines necessary to encourage cogeneration and small power production . . . " to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from the qualifying facility (75).

FERC considered several alternative standards that would have set the purchase rate at less than full avoided cost, including rate standards based on a fixed percentage of avoided costs and on a "split-the-savings" approach. The commission noted that these pricing mechanisms would transfer to the utility's ratepayers a portion of the savings represented by the difference between the QF's costs and those of the utility, and thus would provide an incentive for the utility to purchase cogenerated power (75). The same argument was made by California utilities in opposing purchase power payments based on full avoided costs, but rejected by the Public Utilities Commission (see discussion of PURPA implementation, below) (Io).

However, FERC argued that, in most instances, the resulting rate reductions would be insignificant for individual ratepayers, while if the full savings were allocated to the QF they would provide a significant incentive to cogenerate. Furthermore, FERC felt that a "split-the-savings" approach would require a determination of the costs of power production in a QF—exactly the sort of cost-of-service regulation from which QFs are exempt under PURPA. FERC also argued that a fixed percentage standard would lead QFs to stop producing additional units of energy when their costs exceeded the price to be paid by the utility, and thus could force the utility to operate less efficient generating units or consume more premium fuels (l).

Based on these considerations, FERC determined that only a rate for purchases that equals the utility's full avoided costs for energy and capacity would simultaneously satisfy the statutory requirements that the rate be just and reasonable to ratepayers, in the public interest, and not discriminate against QFs, and fulfill the statutory mandate to encourage cogeneration.

The Court of Appeals ruled that FERC had appropriately rejected the split-the-savings approach because that would "veer toward the public utilities-style rate setting that Congress wanted to avoid" (1). However, the court recognized that other alternatives to the full avoided cost standard might allocate benefits between cogenerators and utilities more evenly without requiring an inquiry into the QF's production costs, and that FERC should take a harder look at these alternative approaches. In particular, the court stated that FERC should reconsider the percentage of avoided cost approach to determine whether it would disproportionately discourage cogeneration. The court argued that the "bare unquantified possibility that a rule permitting rates at less than full cost might be insufficient to encourage the last kilowatthour of cogeneration" is inconsistent with the clear intent of PURPA, which seeks to strike a balance among the interests of cogenerators, electricity consumers, and the public (l).

The court also outlined several additional ways that the avoided cost standard could disadvantage utility ratepayers, and specified that FERC should address these in its subsequent rulemaking. First, the commission should take into account, if possible, elements of utilities' avoided costs that cogenerators would not also have to pay (e.g., where the utility is subject to higher pollution control standards than a cogenerator, when a utility pays taxes at a higher rate than cogenerators). Second, FERC should consider a utility's capacity situation. If a utility has excess capacity, cogeneration stimulated by full avoided cost payments may result in higher rates for the utility's remaining customers (without increasing the utility's total costs) due to the fixed cost declining demand situation, in which the cogenerator reduces the number of customer-purchased kilowatt-hours over which the utility can spread a share of the fixed costs of the extra capacity (see ch. 6). Third, the full avoided cost standard precludes consideration of competitive market forces, that might encourage utilities to purchase a substantial amount of cogenerated power at a price lower than the statutory ceiling (l).

As a result of all of the above considerations, the court held that FERC had not adequately justified its decision to prohibit any purchase power rates below full avoided costs, and vacated the FERC rate regulations and remanded the matter to the commission. However, the court emphasized that its holding:

> . . . should not be read as requiring FERC to establish different standards for a variety of cogeneration cases and methods. A general rule is acceptable, but the Commission must justify and explain it fully, particularly in its balancing of the interests of cogenerators, the public interest, and "electric consumers" (l).

As noted above, the U.S. Supreme Court has agreed to review the appeals court decision.

The purchasing utility normally will be the one with which a cogenerator is directly interconnected (i.e., the "local" electric utility). In some instances, however, either the cogenerator or its local utility may prefer that a second, more distant electric utility purchase the cogenerator's energy and/or capacity. For example, if the local utility has no generating capacity, its avoided cost will be the price of bulk purchased power, which ordinarily is based on the average embedded capacity cost and the average energy cost on the supplying utility's system. But if the QF's output were purchased by the supplying utility directly, that output usually would replace the highest cost energy on the supplying utility's system at the time of the purchase, and the QF's capacity may enable the supplying utility to avoid adding new generating plants. Thus, the avoided costs of the supplying utility may be higher than those of the local nongenerating utility.

Similarly, if the local utility has excess generating capacity and/or relatively inexpensive coal or other alternate-fueled baseload generation, its avoided energy costs could be quite low and it may not have any avoided capacity costs. A neighboring utility, however, may have excess load or expensive oil-fired baseload plants, and thus relatively high avoided costs.

For circumstances such as these, the FERC rules provide that a utility that receives energy or capacity from a QF may, with the consent of the QF, transmit that energy or capacity to a second utility. However, if the QF does not consent to transmission to another utility, the local utility retains the purchase obligation. Similarly, if the local utility does not agree to transmit the QF's energy or capacity, it retains the purchase obligation. Because the transmission can only occur with the consent of the utility to which the energy or capacity is first delivered, this rule does not constitute forced wheeling of power (75).

The FERC rule on transmission of cogenerated power to other utilities specifies that any electric utility to which such energy or capacity is delivered must purchase that energy or capacity under the same obligations and at the same rates as if the purchase were made directly from the QF. As discussed above, these rates should take into account any transmission losses or gains. If the electricity from the QF actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses, and the purchase rate should reflect these losses. Alternatively, the transmission can be fictionalized (as in simultaneous purchases and sales—see below). For instance, energy and/or capacity from a cogenerator may displace bulk power that would have been purchased by a nongenerating utility, as in the example cited above. In this case, the energy from the QF may replace a greater amount of energy than would have been purchased from the supplying utility (since the power from the latter is subject to greater line losses than the power from the QF), and the purchase rate should reflect the net transmission gain (72).

obligation to Sell.–Section 210(a) of PURPA also requires that each electric utility offer to sell electric energy to QFs. The FERC regulations interpret this obligation as requiring utilities to provide four classes of service to QFs: supplementary power, which is energy or capacity used by a QF in addition to that which it generates itself; interruptible power, which is energy or capacity that is subject to interruption by the utility under specified conditions, and is normally provided at a lower rate than non interruptible service if it enables the utility to reduce peakloads; maintenance power, which is energy or capacity supplied during scheduled outages of the QF–presumably during periods when the utility's other load is low; and backup power, for unsceduled outages (e.g., during equipment failure). A utility may avoid providing any of these four classes of service only if it convinces the PSC that compliance would impair its ability to render adequate service or would place an undue burden on the electric utility (73).

PURPA requires that rates for sales of these four classes of service be "just and reasonable and in the public interest, " and that they not discriminate against QFs. The FERC regulations implementing this requirement contemplate the formulation of rates based on traditional cost-of-service concepts (see discussion of rate regulation in the previous section), and specify that rates for sales to QFs shall be deemed nondiscriminatory to the extent that they apply to a utility's non-cogenerating customers with similar load or other cost-related characteristics (73).

Thus, the FERC rules provide that rates for sales of power to QFs must reflect the probability that the facility will (or will not) contribute to the need for and use of utility capacity. If the utility must reserve capacity to provide service to a cogenerator, the costs associated with that capacity may be recovered from the cogenerator if the utility normally would assess these costs to noncogenerating customers. If the utility can demonstrate, based on accurate data and consistent systemwide costing principles, that the rate that would be charged to a comparable non-cogenerating customer is not appropriate, the utility may establish separate rates for QFs according to these data and costing principles. However, any such separate rates must still be nondiscriminatory, so that the cogenerator is not "singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself" (73).

The FERC regulations also specify that rates for sales of backup and maintenance power may not be based, without adequate supporting data, on the assumption that all QFs will experience forced outages or other reductions in output either simultaneously or during the system peak. Thus, QFs are to be credited for either interclass or intraclass diversity to the same extent as non-cogenerating customers, because such diversity will mean that utilities supplying backup or maintenance power to QFs probably will not need to reserve capacity on a one-to-one basis. In addition, rates for backup and maintenance power must take into account the extent to which a QF can usefully coordinate maintenance with the utility (74).

Simultaneous Purchase and Sale.–The FERC regulations specify that a utility must offer to purchase all of a cogenerator's electric power output at avoided cost rates regardless of whether that utility simultaneously sells power to the QF at standard retail rates (72). In effect, this rule separates the electricity production and consumption aspects of QFs, and thus equalizes the treatment of facilities which consume all the power they generate with that of cogenerators which sell some or all of their power (75).

AEP, et al., challenged this rule on the grounds that it misconstrued the statutory terms "purchase" and "sale," because it requires utilities to treat cogenerators as if they have engaged in a purchase and sale when in fact none might have occurred. The Court of Appeals disagreed, holding that FERC'S rule is consistent with PURPA. The court noted that the narrower construction of the statute urged by AEP would result—anomalously–in discriminatorily different treatment for cogenerators that use some or all of their power onsite and those that sell all their electric output. With such a narrow construction, cogeneration could be uneconomical because utility retail rates usually are lower than the utility's incremental energy and capacity costs and the cost of cogenerating.

AEP also argued that FERC did not adequately consider and explain its decision to require utilities to engage in the simultaneous transaction fiction. The court found that FERC had considered the impact of this rule on all interested parties and thus that the rule had been adequately justified (l).

Obligation to Operate in Parallel.–The FERC rules also require each electric utility to offer to operate in parallel with a QF, provided that the QF meets the State standards for protection of system reliability (71). By operating in parallel, a QF can automatically export any electric power that is not consumed by its own load. Thus, the same customer circuits can be served simultaneously by customer- and utility-generated electricity.

Obligation to Interconnect. -In their regulations implementing section 210 of PURPA, FERC argued that electric utilities' obligation to interconnect with QFs is subsumed within the purchase and sale obligations of section 210(a). Moreover, FERC noted that it has ample authority to require utilities to interconnect with QFs under the general mandate of section 210 that the commission prescribe "such rules as it determines necessary to encourage cogeneration and small power production" (75). Consequently, the FERC rules specified that "any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales" (71).

AEP, et al., challenged this rule on the grounds that it was inconsistent with sections 202 and 204 of PURPA (which became sec. 210 and 212 of the Federal Power Act), as well as with PURPA section 210 itself. Section 202(a)(l) provides:

> Upon application of any electric utility, Federal power marketing agency, qualifying cogenerator, or qualifying small power producer, the Commission may issue an order requiring—
>
> (A) the physical connection of any cogeneration facility, any small power production facility, or the transmission facilities of any electric utility, with the facilities of such applicant.

In issuing an order under section 202(a)(l), the Commission must issue notice to each affected party and afford an opportunity for a full evidentiary hearing under the Administrative Procedure Act.

Section 202(c) states that FERC may not issue an order under 202(a)(l) unless FERC determines that the order:

> (1) is in the public interest,
> (2) would–
> (A) encourage overall conservation of energy or capital,
> (B) optimize the efficiency of use of facilities and resources, or
> (C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and
> (3) meets the requirements of section [204].

The requirements of section 204 are that FERC determine that an order issued under section 202(a)(l):

> (1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, qualifying cogenerator, or qualifying small power producer . . . affected by the order;
> (2) will not place an undue burden on an electric utility, qualifying cogenerator, or qualifying small power producer . . . affected by the order;
> (3) will not unreasonably impair the reliability of any electric utility affected by the order; and
> (4) will not impair the ability of any electric utility affected by the order to render adequate service to its customers.

Finally, while section 21 O(e) of PURPA authorizes FERC to exempt QFs from provisions of the Federal Power Act, it specifically excludes sections 202 and 204 from such exemption.

In the AEP case, FERC argued that compliance with sections 202 and 204 of PURPA would impose an undue burden on cogenerators and thus would be contrary to the entire thrust of sections 201 and 210. in particular, FERC noted that in enacting sections 201 and 210, Congress had already determined that QFs serve the purpose of the act to optimize the efficiency of use of facilities and resources by electric utilities, and thus it would be both redundant and unduly burdensome to require QFs to meet all the requirements of sections 202 and 204 in order to sell power to the grid.

However, the U.S. Court of Appeals agreed with AEP, holding that FERC'S rule requiring interconnection was inconsistent with PURPA. The court noted that FERC, in promulgating an interconnection rule that is consistent:

> need not impose substantial administrative burdens on those facilities, but rather can adopt streamlined procedures. If the Commission believes that even streamlined procedures are too burdensome, the necessary amendment must come from Congress (1).

In its petition for rehearing of the AEP decision, FERC emphasized the basic intent of PURPA to encourage cogeneration, and argued that, without the interconnection requirement, the obligation to purchase and sell is meaningless. FERC also contended that PURPA section 210 is independent of, and does not amend, the Federal Power Act, and thus the interconnection requirement must be read into PURPA and the section 202 and 204 provisions interpreted as an alternative means of obtaining interconnection.

If the AEP decision is upheld by the Supreme Court, then QFs who cannot get a utility to agree to interconnect will have to apply for a FERC order under the procedures outlined in section 202(a)(l), and thus meet the evidentiary requirements of sections 202 and 204. However, the requirements of sections 202(c) and 204 would be very difficult and expensive for a QF to meet. Even in well-understood situations, the expenses and delays associated with evidentiary hearings under the Administrative Procedure Act will deter all but those who have a pressing need for an administrative order. But the multiple stringent legislative tests of sections 202(c) and 204 are couched in new, broad language that will have to be construed, first, by FERC and then, in all likelihood, by the courts. Thus, these provisions pose a substantial deterrent to cogenerators that cannot get an electric utility to voluntarily interconnect with them–exactly the problem PURPA was intended to remedy. Options for resolving this issue are discussed in chapter 7.

Under the FERC regulations implementing PURPA, a QF must reimburse any electric utility that purchases energy or capacity from the facility for interconnection costs. These costs are defined in the regulations as:

> . . . the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the electric utility and directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent that such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources (68).

Interconnection costs must be assessed on a nondiscriminatory basis with respect to noncogenerating customers with similar load characteristics, and may not duplicate any costs included in the avoided costs (74). Standard or class charges for interconnection may be included in purchase power tariffs for QFs with a design capacity of 100 kW or less, and PSCS may also determine interconnection costs for larger facilities on either a class or individual basis.

State regulatory commissions have the authority to ensure that utility requirements for system safety equipment and other interconnection requirements and their associated costs are reasonable. In practice, utility interconnection requirements vary widely (see ch. 4) and few PSCS have addressed the interconnection question directly.

OTHER PURPA BENEFITS

Qualifying cogenerators are exempt from regulation as a public utility or a utility holding company under the Federal Power Act and PUHCA, and from State laws regulating the rates, structure, and financing of utilities. However, if a regulated electric utility owns more than a 50-percent equity interest in a qualifying cogenerator, the cogenerator will be subject to the traditional jurisdiction of ratemaking authorities to the extent of utility ownership. In addition, qualifying cogenerators may be eligible for an exemption from the FUA prohibitions on oil and gas use and from the incremental pricing provisions of NGPA.

IMPLEMENTATION OF SECTION 210

The FERC regulations on section 210 of PURPA required State public utility commissions (PUCS) to begin implementation of the regulations by March 1981. Since that time, a wide range of draft and final rules have been issued by the States, and utilities have published a variety of tariffs for cogenerated power (see table 19). The State PUCS have taken full advantage of the procedural latitude allowed by the FERC rules, using rulemaking, adjudication, and dispute resolution to es-

Table 19.—Rates for Power Purchased From QFs by State-Regulated Utilities

Utility	Energy payments (cents/kWh)	Capacity payments ($/kW-yr)	Comments
Alabama			Nuclear 24%, coal 58%, oil 1%, gas 3%, hydro 14%.
Alabama Power Co.	2.59 on-peak, June-October 2.17 off-peak, June-October 2.14 on-peak, November-May 2.05 off-peak, November-May		Off peak purchase rates are offered for utilities without time-of-day metering. Rates are for facllities less than 100 kW.
Arkansas			Nuclear 17%, coal 9%, oil 44%, gas 10%, hydro 20°A
Arkansas Power & Light Co.	Reverse metering currently used		Comments on proposed rates were due by June 1, 1981.
California			Nuclear 4%, oil 67%'., gas 1%, hydro 25%, other 3%.
Pacific Gas & Electric Co.	6.58 on-peak 6.219 mid-peak 5.553 off-peak 6.030 non-TOD	$0.75-$1.50/kW-month	Rates are for February-April 1981.
Southern California Edison	6.6 on-peak 6.0 mid-peak 5.8 off-peak 6.0 non-TOD	25% of full value	Rates are for February-April 1961.
San Diego Gas & Electric Co.	8.333 on-peak 7.069 mid-peak 6.225 off-peak 6.850 non-TOD	$0.70-$2.00/kW-month	Rates are for February-April 1981.
Connecticut			Nuclear 38%, oil 80°/0, hydro 2%.
Connecticut Light & Power Co. and Hartford Electric Light Co.	Firm power 6.7 on-peak (114.5% of fossil fuels cost) 5.4 off-peak (90.5% of fossil fuels coat) Nonflrm power 6.6 on-peak (110% of fossil fuels cost) 5.2 off-peak (86.5% of fossil fuels cost)		Purchase rates are temporarily In effect pending approval of utlllty proposals. Percentage is tied to monthly fuel adjustment. Firm power rates are for facilities greater than 100 kW. Off-peak purchase rates are offered for facilities without tlme-of-day metering. No size restrictions apply to non-flrm facilities.
Idaho			Oil 1%, gas 3%, hydro 96%
Utah Power & Light Co.	Firm power 1,2 Non.firm power 2.6	88-268 Increasing with contract length 4-35 years.	The Idaho PUC has ordered UP&L to add some capacity credit to the non-flrm energy payment.
Washington Water Power Co.	Firm power 1.6 Nonfirm power 2.4	96-280 Increaslng with contract length 4-35 years. 0.3cents/kWh	
Idaho Power Co.	Firm power 1.639	116-318 Increasing with contract length 4-35 years.	Rates are for facilities less than 100 kW.
	Nonflrm power 1.41-3.86 (varies each month, 2.4 average)		The Idaho PUC has ordered IPC to add some capacity credit to the non-flrm energy payment.
Illinois			Nuclear 19%, coal 57%, oil 23°/0, < 1% gas, <1 % hydro, 1 % other.
Illinois Power	2.42 on-peak summer 1.55 off-peak summer 2.65 on-peak winter 1.88 off-peak winter Non-TOO: 1.89 summer 2.18 winter		
Commonwealth Edison	5.31 on-peak summer 2.90 off-peak summer 5.17 on-peak winter 3.37 off-peak winter		1,000 kW or less.
Central Illinois Light Co.	34 kV or greater 2.3 on-peak 2.1 off-paak 12 kV to 34 kV: 2.4 on-peak 2.2 off-peak Less than 12 kV: 2.5 on-peak 2.3 off-peak		

Table 19.—Rates for Power Purchased From QFs by State-Regulated Utilities-Continued

utility	Energy payments (Cents/kWh)	Capacity payments ($/kW-yr)	Commenta
Interstate Power Co.	2.45 on-peak, June-September 2.05 off-peak, June-September 2.19 on-peak, October-May 2.05 off-peak, October-May		
Central Illinois Public Service	1.978 on-peak summer (3 months) 1.620 off-peak summer 1.884 on-peak winter (3 months) 1.861 off-peak winter 1.805 on-peak (rest of year) 1.565 off-peak		
South Beloit Water, Gas & Electric Co.	2.30 on-peak 1.70 off-peak		
Union Electric	*Non, TOD:* 1.77 summer 1.53 winter *TOO:* 2.41 on-peak summer 1.36 off-peak summer 1.50 summer, weekends and holidays 1.86 on-peak winter 1.35 off-peak winter 1.35 winter, weekends end holidays		
Indiana			Nuclear O%, coal 89%, oil 8%, gas < 1%, hydro 1%, other 2%.
Indiana & Michigan Eiectric Co.	*TOQ:* 1.36 on-peak 0.81 off-peak *Non.TOD: 0.81*		
Indianapolis Power & Light	1.14 general rate *Seaaonal:* 1.19 on-peak summer 1.07 off-peak summer 1.28 on-peak winter 1.08 off-peak winter		
Northern Indiana Public Service Co.	2.62 on-peak summer 2.29 off-peak summer 2.61 on-peak winter 2.29 off-peak winter *Norr. TOD seasonal:* 1.86 summer 1.83 winter		
Public Service Co. of Indiana	1.33		
Southern Indiana Gee & Electric	1.49 on-peak summer 1.02 off-peak summer 1.15 on-peak winter 1.00 off-peak winter		
Richmond Power & Light	0.914		
Kansas			Coal 35%, Oil 11%, gas 55%.
Kansas Power & Light	1.60		Rate is for a cogenerator on-line since the 1920's.
Massachusetts			Nuclear 9%, coal O%, oil 72%, gas <1%, hydro 18°/0, other 1%.
Boston Edison	6.971 on-peak 4.047 off-peak 5.543 flat		
Commonwealth Electrlc	7.16 on-peak 6.15 off-peak 6.51 flat		Interim rates. Energy rates wIII be reset every 3 months when fuel adjustment is figured. QFs of 30 kW or less can use reverse metering.
Eastern Edison	8.792 on-peak 5.161 off-peak 5.995 fiat		
Massachusetts Electric	5.51 on-peak 4.79 off-peak 5.08 fiat		
Cambridge Electric	7.22 on-peak 5.91 off-peak 6.34 fiat		
Nantucket Electrlc	7.44		
Manchester Electric	4.748		
Fitchburg Gas & Eiectrtc	6.081 on-peak 3.313 off-peak 4,940 flat		
Western Massachusetts Electric	5.813 on-peak 4.238 off-peak 4.979 flat		
Michigan			Nuclear 14°/0, coal 47%., oii 230/o, gee 4%, hydro 11 O/., other 1'/0.
Statewide purchase rate includes: Consumers Power Co. and Detroit Edison	2.5		This rate was established prior to PURPA compliance. New purchase rates implemented in March or April of 1982.
MInnesota			Nuclear 21%, coal 55°/0, oil 19%, gas 1%, hydro 2%, other 2%.

Table 19.—Rates for Power Purchased From QFs by State”Regulated Utillties—Continued

utility	Energy payments (cents./kWh)	Capacity paymenta ($/kW-yr)	Comments
Northern States Power Co,	*Firm power* 2.08-3.07 increasing with contract length 5-25 years. *TOD metering service:* *2.15* on-peak 1.39 off-peak *Nonfirm power :* 1.35 *Occasional power* 1.66		Temporary rate schedule in effect until further studies are completed. These rates are intended to comply with PURPA requirements and are restricted to facilities less than 100 kW. Capacity credits are included in firm power purchase rates. Non-firm power rates take effect in the event that a firm producer does not provide dependable generation. Occasional power is limited to 500 kWh/month.
Montana			Nuclear 0%, coal 32%, oil 5%, gas 1%, hydro 61 O/., other 1%.
Montana Power	2.7842	77.24 (25-yesr contract only)	
Montana-Dakota	*Nonfirm power* *2.21* on-peak 1.57 off-peak *Non firm, non-TOD: 1.91* *Firm power:* *1.97-3.08* (depending on contract length)		Non-firm rates for QFs of 100 kW or less.
Pacific Power & Light	1.34-1.88	3.75-7.37 per kW-month	
Nebraska			Nuclear 26°/0, coal 48°/0, oil 130A, gas 9%., hydro 30A, other 3%.
Omaha Public Power District	*TOD metering:* 1.60 on-peak summer 1.00 off-peak all year 1.20 on-peak winter *Standard rate:* 1.10		Rates apply to facilities of 100 kW or less.
Nevada			Nuclear O°/., coal 540/', oil 5%, gee 23%, hydro 18%.
Idaho Power	1.71 (February)- 4.16 (August)	116.00-263.00 (1981)	Energy payments vary monthly. Capacity payments vary by length of contract.
Sierra Pacific	4.09	6.1cents/kWh	
Nevada Power Co.	3.802 on-peak, October 1961 1.943 off-peak, October 1981 3.528 on-peak, November 1981 2.331 off-peak, November 1981 4.311 on-peak, December 1981 2,630 off-peak, December 1981	8.55 on-peak October 1981 0.07 off-peak October 1961 0.14 on-peak November 1981 0.00 off-peak November 1981 0.14 on-peak December 1981 0.00 off-peak December 1981	Energy payments and capacity payments vary monthly.
New Hampshire			coal 30%, oil 47 %, hydro 23%.
Statewide rate	*Firm power* 8.2 *Nonfirm power 7.7*		Granite State Electric Utility is not required to pay the firm power rate due to excess capacity.
New Jersey			Nuclear 14%, coal 13%, oil 690/', gas 1%, hydro 3%.
Jersey Central Power and Light Co.	*Approximate only:* *6.0-7.5* on-peak 2.0-5.0 off-peak		Actual rates are determined by averaging marginal energy rates for previous 3-month on-peak and off-peak hours. The rate appiies to facilities between 10 and 1,000 kW.
Atlantic City Electric Co.	*Temporary rate: 2.5*		This October 1980 rate was greater than average energy costs. The utility has proposed that buyback rates may be set at time of interconnection.
New York			Nuclear 13%, coal 8%, oil 83%, hydro 15%°, gas and other 1%.
Statewide minimum rate includes: Long island Lighting Co., Niagara Mohawk Power Co., New York State Electric & Gas CO., Consolidated Edison, Orange & Rockland Utilities, Inc., Central Hudson Gas & Electric Corp. and others	6.00 minimum		
North Carolina			Nuclear 110/0, coal 71%, oil 6%, hydro 12%.
(Note: North Caroiina capacity payments are given as cents/kWh not $/kW-yr as shown above.)			
Carolina Light & Power Co.	2.60-5.55 on-peak 2.074.04 off-peak	1.49-2.39 summer month 1.29-2.08 non-summer months	Rates increase with contract length.
Duke Power Co.	2.38-5.20 on-peak 1.78-3.91 off-peak	1.11-1.88 on-peak months 0.68=1.00 off-peak months	Rates increase with contract length.
Virginia Electric & Power CO.	4.23-9.30 on-peak summer 3.59-4.30 peak non-summer 2.82-5.77 all others	1.61-2.50 summer 1.42-2.25 non-summer	Rates increase with contract length.
Nanthahala Power & Light Co.	2.05	2.50	NP&L purchases power from TVA.
North Dakota			Coal 82%, oil 4%, hydro 14%.
(Note: proposed rates–not yet finished.)			
Northern States Power Co.	2.15 on-peak 1.39 off-peak	2.06-3.07 (cents/kWh)	Rates apply to facilities less than 100 kW. Capacity payments increase with length of contract 5-25 years. Facilities larger than 100 kW treated case-by-case.

Table 19.—Rates for Power Purchased From QFs by State-Regulated Utilities—Continued

Utility	Energy payments (cents/kWh)	Capacity payments ($/kW-yr)	Comments
Okiahoma			Nuclear O%, coal 20%, oil 3%, gee 65°/0, hydro 80A, other 40/o.
Statewide rate schedule includes: Oklahoma Gas & Electrlc Co. Public Service Co.	0.66-3.05 depending on firmness of capacity		Formulae have been established to treat purchase rates for various types of small power producers. Both energy and capacity components are considered.
Oregon	Reverse metering currently used		Nuclear 12%, coal 00/', oil 70A, gas 1%, hydro 78°/0, other 2%.
Rhode Island			Nuclear O%, coal O%, oil 99%, gas O%, hydro 1 %.
New England Power Co.	5.5247 on-peak 4.5339 off-peak 4.9643 average		
Blackstone Valley Electric Co.	*Primary:* 6.412 on-peak 4.642 off-peak 5.511 average *Secondary:* 6.726 on-peak 4.965 off-peak 5.723 average		
Newport Electric Co.	4.473 on-peak 4.093 off-peak 4.317 average		
South Carolina			Nuclear 29%, coal 300/., oil 210/0, hydro 19°/0, gas and other 1%.
Carolina Power & Light Co.	2.60 on-peak 2.07 off-peak	46.68 summer 40.20 non-summer	Rates are for facilities less than 5 MW.
Duke Power Co.	1.96 on-peak 1.49 off-peak	60.00 (Based on integrated capacity during peak months June-September, December-March).	
Utah			Coal 86%, oil 2%, gas 2%, hydro 1O%.
Utah Power & Light Co.	2.2 (temporary rate)	2.6cents/kWh	Purchase rates are for facilities less than 1,000 kW (100 kW for hydro). Larger facilities are considered case-by-case (up to 3.5cents/kWh).
C.P. National	2.2 (temporary rate)	2.66cents/kWh	
Vermont			Nuclear 57%, coal 3%, oil 16°/0, hydro 24%.
Statewide rate schedule	7.8 standard rate TOD *rates:* 9.0 on-peak 6.6 off-peak		Avoided costs are higher than would be expected from Vermont's capacity mix due to dispatch and accounting practices of NEPOOL.
Wisconsin			Nuclear 17%, coal 59%, oil 170/., gas 20/., hydro 5°/0.
Wisconsin Power & Light Co.	1.60 on-peak 1.75 off-peak (includes capacity)		Purchase rates are for facilities less than 200 kW. Larger facilities are treated case-by-case.
Madison Gas & Electric Co.	2.75 on-peak summer 1.50 off-peak summer 2.22 on-peak winter 1.50 off-peak winter		Purchase rates are for facilities less than 200 kW. Larger facilities are treated case-by-case.
Wisconsin Electrlc Co.	*Firm power:* 3.65 on-peak summer 1.45 off-peak summer 3.45 on-peak winter 1.45 off-peak winter *Non firm power:* 2.90 on-peak 1.45 off-peak		
Northern States Power Co.	*For 20 kW or less:* 1.81 on-peak 1.14 off-peak *For 21-500 kW after 1986:* 1.60 on-peak 1.14 off-peak	$4/kW/month S4/kW-month	Prior to 1966 the rates for 20 kW and less apply to 21-500 kW. No capacity credits will be paid until after 1966. Facilities greater than 500 kW are treated case-by-case.
Lake Superior District Power Co.	1.90	S6.02/kW-month	Purchase rates are for facilities between 6 and 200 kW. Smaller facilities receive no payments. Larger facilities are considered case-by-case.
Wisconsin Public Service Corp.	1.65 on-peak 1.32 off-peak	To be determined according to characteristics of each facillty.	
Wyoming			Coal 93%, hydro 6%, oil and gas 10/..
(Note: All of the Wyoming purchase rates are "experimental.")			
Utah Power & Light Co.	*Non-firm power: 2.2* *Firm power 2.6*		Purchase rates are for facilities less than 100 kW.
Cheyenne Light, Fuel and Power Co.	*0.53*	Available on demonstration of demand reduction.	
Tri-County Electric Association	1.07		This is a non-generating utility which has based its avoided costs on wholesale supply rates.
Montana-Dakota Utilities Co.	0.405	Available on demonstration of capacity displacement or demand reduction potential.	

SOURCE: Reiner H. J. H. Lock and Jack C. Van Kuiken, "Cogeneratlon and Small Power Production: State Implementation of Section 210 of PURPA," 3 *Solar L Rep. 659* (November-December 1961).

tablish rates and operating criteria. These procedures have resulted in a wide diversity in State approaches to PURPA as well as in the rates established thereunder. A comprehensive survey of State implementation actions and cogeneration potential is beyond the scope of this assessment. Moreover, the status of these actions is uncertain due to the Court of Appeals case discussed above. Therefore, this section will present case studies based on the implementation of title II in three areas: California, where cogeneration has a potentially large market and the State government is actively promoting its use; Illinois, where cogeneration's technical potential could be significant but the market will be limited by the electric utilities' large construction budget; and New England, where existing excess capacity, extensive pooling agreements, and planned conservation measures will influence cogeneration's market potential. It should be emphasized that these case studies do not typify the range of State and utility actions on PURPA. Rather, they represent examples of three kinds of planning situations that will affect PURPA'S implementation. The same case study areas are used in the analysis of cogeneration's potential impacts on utility planning and regulation in chapter 6.

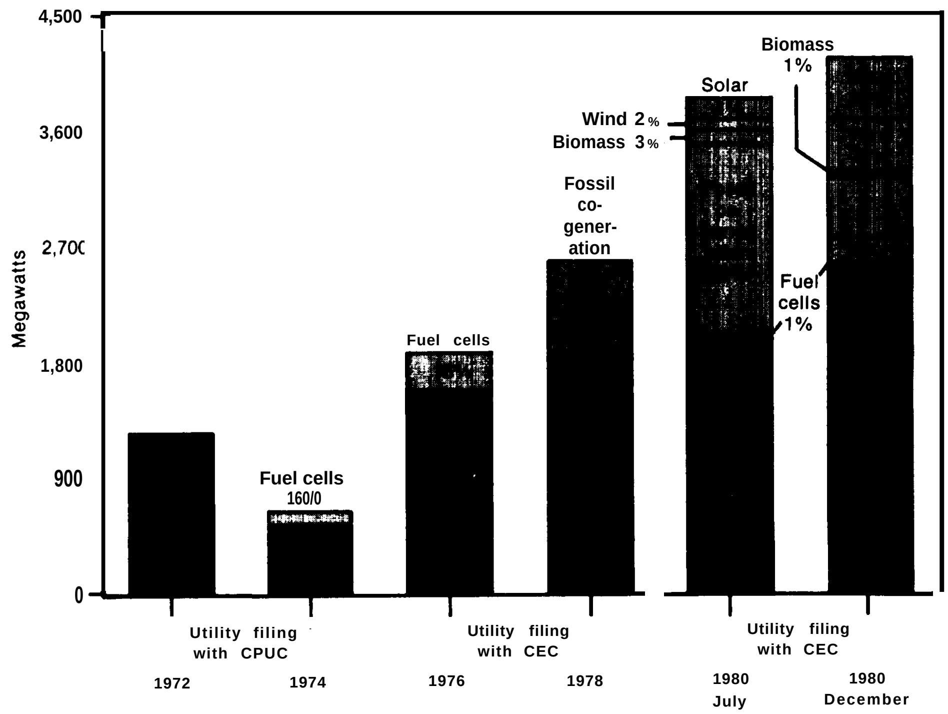
California.—The dominant factor in California utilities' capacity planning is not demand growth, but the need to reduce their dependence on oil. Planning and construction of new coal and nuclear baseload facilities was limited during the 1970's as demand growth declined, and cancellations and postponements of coal and nuclear capacity left the State's utilities heavily dependent on oil and natural gas. The California Energy Commission's (CEC) 1981 final report on electricity projects an annual energy growth rate (measured in GWh) of less than 1.5 percent through 1992, but a capacity growth rate of approximately 2.5 percent per year (5). The capacity growth rate is higher because it includes a projected 30-percent reserve margin (in case the energy growth rate is higher than 1.5 percent), the replacement of retired powerplants and expired purchase power contracts, and the reduction of utility oil and gas consumption Statewide to one-half the 1979 level by 1992.

The CEC report identifies three priorities that should be sufficient (according to the report) to provide the needed energy and capacity for the 1980-92 period: 1) additional conservation and power pooling; 2) geothermal and renewable resources (biomass, wind, solar, small hydro, and existing reservoirs); and 3) cogeneration and interstate electricity transfers. CEC estimates that cogeneration could provide up to 3,000 MW of generating capacity by 1992. Their estimate is bracketed by the California utilities' long-range resource plans, which project 1,900 MW of cogeneration capacity by 1992, and the Natural Resources Defense Council estimate of 4,300 MW by 1995 (5).

State regulators in California had taken a number of regulatory actions favoring cogeneration even before the FERC rules implementing PURPA section 210 became final. The California Public Utilities Commission (CPUC) investigated the role of cogeneration in utility resource planning (see fig. 13) and, in 1979, ordered Pacific Gas& Electric (PG&E), in particular, and all of the State's electric utilities in general, to adopt a specific timetable for bringing cogeneration capacity into the electrical system. Under the CPUC order, PG&E was expected to bring 2000 MW of cogeneration into the resource base by 1985, principally through contracts tied to the avoided cost of oil-fired utility capacity that is displaced (8). In a companion decision (this time in a PG&E general rate case), CPUC imposed a rate-of-return penalty on the company's electric division for failure to implement cogeneration projects aggressively. The penalty, which represented over $7 million in annual revenues, or 0.2 percent in return on equity, was to be restored if PG&E brought 600 MW of cogeneration capacity under contract by 1982 (7). Although PG&E was not able to meet this goal, the CPUC staff recommended, late in 1981, that the penalty be discontinued because the utility's performance in encouraging cogeneration has been adequate (41).

PG&E planners argue that the CPUC goals of 2,000 MW by 1985 are unrealistic. In a major planning study, PG&E estimated the cogeneration market potential in their service area to be between 204 and 903 MW of capacity additions

Flgure 13.–Statewide Utility Resource Plan Additions 1981=82: Renewable/lnnovative Technologies



SOURCE: California Energy Commission, Electricity *Tomorrow: 1981 Final Report* (Sacramento, Callf.: *Ca/item/a* Energy Commission, 19S1).

by 1990 (beyond the 472 MW already operating), and their long range resource plan projects 190 MW additional cogeneration capacity by 1985, and 600 MW by 1992. PG&E's anaiysis suggests that industry would have to commit approximately 12.5 percent of their total annual capital expenditures to cogeneration in order to meet the CEC goal of 2,000 MW under contract by 1985 (41).

The California regulatory climate is unique. In no other State has the public utility commission participated so actively in capacity and resource planning. Encouraging cogeneration is an explicit policy expressed in price signals to the utility and from the utility to the potential cogenerator. Despite these attitudes that favor cogeneration development, however, there remain significant questions and uncertainties about the amount of cogeneration capacity that can be counted on, and thus about the other types of capacity additions that may be needed.

one major difficulty in assessing the extent of future cogeneration development in California lies in the special nature of the market, namely, the potential for large enhanced oil recovery cogeneration projects. The heavy oilfields in Kern County, Calif., require steam injection or other advanced techniques for economic production. Converting existing steam boilers in these fields to cogeneration would involve projects with 200 to 300 MW of generating capacity. CEC has studied at least six of these projects, and one contract has been signed for 66 MW. Aggregate cogeneration potential in the California oilfields has been estimated by various sources to be between 700 and 10,000 MW or more, depending on the price of oil and the cogeneration technology employed (5,6,31 ,59).

In January 1982, CPUC issued their final decision on rates and other standards for cogeneration and small power production pursuant to the FERC rules implementing sections 201 and 210 of PURPA. In general, this decision, known as OIR-2, requires utilities to file standard offers applicable to QFs larger than 100 kw and tariffs for smaller facilities. Both the standard offers and the tariffs are complete packages that include prices for power purchases and sales, requirements for interconnection, and other relevant factors. Once a utility's tariff and standard offer terms are approved by CPUC, purchases can be made under them without further administrative review, and the utility can recover its expenses for such purchases through an energy cost adjustment clause in the same manner as it recoups other purchase power expenses (10).

Under OIR-2, utilities must file an array of standard offers based on different terms and conditions in order to provide QFs larger than 100 kw with a sufficiently wide choice of options to meet their particular needs, and thus to minimize the use of nonstandard contracts that would have to be reviewed individually by CPUC. In general, these include standard offers for energy and capacity delivered by a QF both "as-available" and under a firm contract, and for energy and capacity prices based on both the utility's shortrun and longrun marginal cost.

Standard offers for "as-available" energy and capacity are based on the utility's avoided cost at the time of delivery, which is the cost the utility would have to incur to produce an equivalent amount of power at that time, or the utility's shortrun marginal cost. The energy component of this standard offer is defined as the highest variable operating cost per unit of electricity produced at a given time, and equals the product of: 1) the purchase price of oil used as the marginal fuel over the last 3 months, and 2) the forecast incremental heat rates* of the plants actually used by the utility to follow load. The as-available energy price also includes an aggregate adjustment for transmission and distribution costs and line losses or savings. In OIR-2, CPUC decided that it was not reasonable to treat these costs on an individual basis except for facilities larger than 1 MW at remote sites.

*Heat rate is a measure of thermal efficiency expressed in Btu input per net kilowatthour output (see ch. 4). The marginal, or incremental, heat rate is calculated as the additional (or saved) Btu to produce (or not produce) the next kilowatthour.

The as-available capacity payment equals a marginal shortage cost that reflects the effects of the added increment of production on reserve margins and reliability, and is determined based on the 1982 estimated cost of peaking capacity (represented by a combustion turbine). This capacity payment is in cents/kWh varying by time of delivery, and is available only for energy delivered through a meter to the utility. Thus, simultaneous purchase and sale QFs will receive the capacity value for all the electricity they generate because their entire output is metered at the generator before any goes to the QF's load or the utility. Other QFs will only receive the capacity value of the electricity actually delivered to the utility (10).

Standard offers for energy and capacity delivered under long-term contracts can be based on either the utility's shortrun or longrun marginal cost. For shortrun marginal costs, energy prices can be contracted for up to 5 years based on a forecast of the utility's variable operating cost (described above). The QF must commit to deliver all the electricity it produces to the utility over the contract period. These contractual energy payments can be combined with either as-available capacity payments or with firm capacity payments based on shortrun marginal costs (1 O).

Firm capacity is equivalent to an increase in supply with corresponding standards, termination provisions, and sanctions regarding dispatchability, reliability, availability, and other factors specified in the FERC rules. The value of each of these factors is calculated based on the same performance standards utilities impose on their own generating plants. If a QF exceeds utility standards, its capacity value should be increased correspondingly. The sum of each of these factors determines the overall capacity value, which is to be offered on both a $/kW/yr and a cents/kWh basis (10).

Alternatively, QFs can choose a contract period of up to 25 years with a firm pricing structure for energy and capacity based on the utility's longrun marginal costs. This standard offer option was included due to concerns that shortrun marginal costs would be too volatile to provide financial certainty and would not adequately reflect a QF's value in the utility's long-range resource plans. The longrun marginal costs are estimated based on the fixed costs associated with the utility's resource plan and the corresponding system projected marginal operating costs (10).

Standard tariffs for QFs smaller than 100 kW provide for purchase power payments in cents/kWh calculated in the same manner as the as-available rates for larger facilities (described above). These tariffs may be time-differentiated, but if a small QF chooses not to buy a time-of-use meter, the utility may offer capacity payments that aggregate over 1 year to 50 percent of the capacity provided by facilities with such meters (lo).

Both standard offers and tariffs also provide for sales of supplementary, backup, maintenance, and interruptible power to QFs. The first three normally are provided under the regular rate schedules applicable to all customers of the same class. However, the demand charges associated with such rates are substantially lower for QFs than for other customers, and may be waived if the facility maintains an 85-percent on-peak capacity factor. Interruptible rates apply to QFs to the extent their generation is used to serve their own load (10).

Finally, CPUC allows nonstandard offers (those that vary from the terms described above) when they are necessary to shift some of a project's risk from the QF to the ratepayers (e.g., in the case of debt guarantees, levelized payments, or payment floors). in return for accepting such risks, ratepayers are afforded some reduction on avoided cost payments. In general, the reasonableness of nonstandard offers will be determined during the annual review of energy cost adjustment clauses or other normal rate proceedings. However, during the first 2 years of OIR-2'S implementation CPUC will provide advance review of those nonstandard offers about which a utility has significant questions (10).

It is not clear how the California Public Utilities Commission would revise OIR-2 in the event that the FERC regulations implementing PURPA are revised to require payments for QF power at less than the utility's full avoided cost. The utilities have argued that full avoided cost payments based on their highest variable operating cost, as determined by the price of oil used on the margin, does not reflect the utilities' actual fuel mix, and thus does not allow ratepayers to share the benefits of QF generation at a cost potentially below the utility's marginal cost, nor does it compensate utilities or their shareholders for the potentially higher risks of reliance on QF energy and capacity. In issuing OIR-2, CPUC considered arguments by the patties that full avoided cost payments disadvantage ratepayers (the same argument accepted by the U.S. Court of Appeals against the FERC rules, as discussed previously). However, CPUC found that only full avoided cost payments would parallel the prices that would be established in a competitive market, and thus give consumers an efficient price signal and "encourage the fullest possible efficient development of QF resources that can effectively and economically compete with utility resources" (1 O).

On the other hand, CPUC did explicitly recognize that payments at less than the full avoided cost are appropriate when some of the risk of investing in QFs is transferred to the ratepayers. CPUC also requested comments from interested parties on whether utilities should receive a percentage of the avoided cost (e.g., one-half of 1 percent) as a brokerage fee for serving as intermediaries between QFs and electricity consumers. However, in such a scheme, the full avoided cost would still be passed on to ratepayers through the energy cost adjustment clause (lo).

It is instructive to contrast the California cogeneration planning situation with roughly analogous efforts in New York by the Consolidated Edison Co. (ConEd). The potential cogeneration market in ConEd's service territory may be large, but the principal ConEd customers likely to cogenerate are large commercial buildings. Their primary economic motive would be to avoid high electricity bills, and they are less likely to sell excess power to the utility than California projects. Given the large number and homogeneity of ConEd's potential cogenerators, it is possible to analyze the market systematically.

Con Ed constructed a model of the cogeneration investment decision that calculates the costs and benefits of investing in cogeneration and measures the internal rate of return from such investments. Where this return, on an aftertax basis, would be 15 percent or better over a 10-year horizon, Con Ed assumed the investment would be made. In order to estimate market size, this model was applied to the load data describing ConEd's 4500 largest customers. Depending on input assumptions, Con Ed found a high range of up to 750 potential cogenerators with a combined peakload of 1,483 MW, and an expected outcome or base case of 395 cogenerators with a combined peakload of 1,086 MW. ConEd has used this model to characterize the sensitivity of market size to the policies that would reduce their "loss exposure" to cogeneration (48).

ConEd's loss exposure stems from a fixed-cost/declining demand problem. Because demand is not expected to grow, cogenerators leaving the system will shift a burden of fixed costs onto the other remaining customers. This would not be a problem if there were enough new kWh sales or customers to replace the cogenerators leaving the system, but ConEd does not anticipate such growth. Situations such as the fixed-cost/declining demand problem, in which cogeneration has a potential to operate to the financial detriment of utilities, are discussed in more detail in chapter 6.

If State regulators are asked to protect utility sales from loss exposure, the utilities must demonstrate that the problem is real and substantial in magnitude. ConEd's cogeneration model purports to make such a demonstration. However, the New York Public Service Commission (NYPSC) argued that the model results were extremely sensitive to input assumptions, and asked Con Ed to run the model using slightly higher costs for cogenerators but holding utility rates constant. The result was an extremely small market potential, with only 27 customers (130 MW of peakload) leaving the system (48). At this level of loss, there is no substantial economic threat to Con Ed. The NYPSC staff argued further that the actual market may be either smaller or larger than this estimate, and until market penetration is more certain, no policy changes are needed to protect ConEd's sales from loss exposure.

This loss exposure problem has not arisen in California. Thus, while CPUC is creating a climate favorable to large-scale cogeneration development, it also is encouraging or ordering utilities to aggressively pursue conservation plans, including developing investment/finance plans for residential weatherization and solar water heating retrofit (9).

Illinois.–Electric utilities in Illinois currently are engaged in a massive construction program that began before the 1973 escalation in oil prices. The largest companies, Commonwealth Edison (CWE) and Illinois Power (1P) are most heavily involved in new construction. CWE has six nuclear units at various stages of completion, while 1P, a company roughly one-fifth the size of CWE, has one.

The financial burden of this construction has become increasingly onerous as utility kwh sales growth has lagged behind expectations. In the case of CWE, the strain has appeared in the rapid decline of their bond rating. In June 1980, Standard and Poor's lowered the rating on CWE debentures and pollution control bonds to BBB, the lowest rating acceptable to institutional investors. The rapid downgrading threatens to limit the market for CWE debt securities, because investors may not want to risk the possibility of further rating cuts (35).

Moreover, in order to finance their $1 billion per year construction program, CWE needs more cash income. In 1979, CWE reported $297 million in net income to stockholders, but $222 million of this was for AFUDC. Thus, 75 percent of net income did not represent cash (compared to an industrywide 1979 average of 38 percent) (13). To improve CWE'S cash flow (as well as that of 1P), the Illinois Commerce Commission (ICC) has allowed some portion of construction work in progress (CWIP) to be included in the rate base. At the end of 1980, CWE had a balance of $4.14 billion in their CWIP account, while IP had $920 million (24).

Planning under these conditions leaves relatively few options for the utility and the State regulators. ICC has initiated investigations into electric load forecasting and reserve margin/reliability issues, but the only feasible option is delaying part of the CWE construction program. With this option, the tradeoff is between extra fuel savings and avoided escalation of costs from completing construction, versus delayed fixed charges by postponing it. The relative value of these factors depends on the projected growth rate in kWh sales. Lower sales growth means smaller fuel savings and a decreased value of completing construction. In its study of delaying two of CWE'S nuclear units, the ICC staff found that even with zero growth in kWh sales, it was better to complete construction without delay (65).

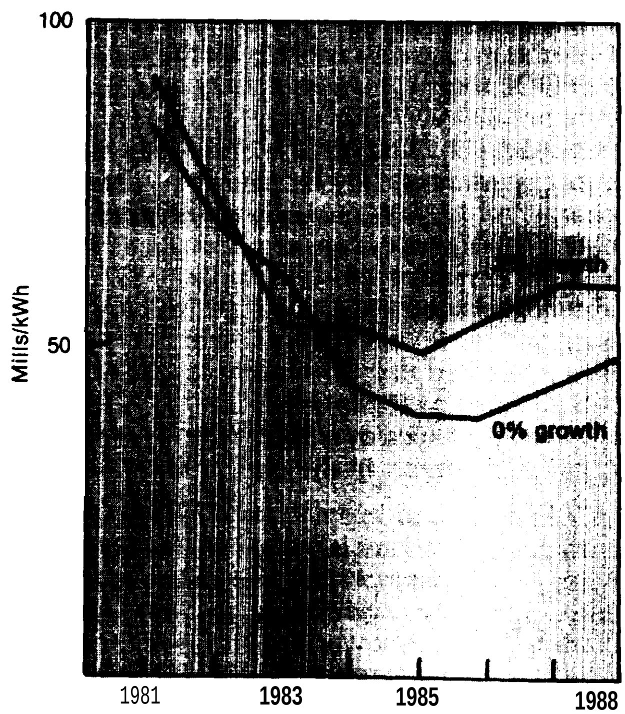
In contrast to the California regulatory system, ICC has not developed an independent forecasting capability. Instead it has channeled its administrative resources into financial analysis and production cost modeling to allow independent regulatory assessment of the costs and benefits of construction delays (albeit with many engineering assumptions determined by utility data). The production cost modeling will provide a basis for establishing purchased power rates as required by PURPA section 210. By contrast, the California agencies have devoted relatively few resources to financial and production cost modeling, but instead have concentrated *on* demand forecasting (35).

Given the lack of flexibility in any of the construction commitments of CWE and 1P, ICC has chosen to avoid conflict over future demand growth expectations. The sensitivity of ICC to the financial strains of the utilities makes it unlikely that any effort will be directed toward demand reduction policies (35). The more relevant question in this jurisdiction is the extent to which ICC can shelter the utilities from the damaging financial impacts of competition either from conservation measures or from cogeneration and small power production.

ICC established purchase power rates for QFs based on a time-of-day rate structure that reflects avoided costs both on-peak and off-peak as well as seasonal adjustments. These rates vary depending on the utility's fuel mix. Thus CWE—which is roughly 40 percent coal, 30 percent oil, and 30 percent nuclear—offers energy payments on-peak that are only slightly lower than those offered by PG&E (see table 19). However, the other major Illinois utilities, which have 85 to 98 percent coal-fired capacity, have much lower avoided costs. None of the Illinois utilities is offering capacity payments to QFs, due to the current excess capacity situation in that State (39).

The future avoided cost path for CWE depends critically on the growth rate of kwh sales. High growth will require continued reliance on oil and gas for a significant fraction of annual energy requirements, but at an average annual rate of 2 percent or less the primary avoidable fuel will be coal. Average avoided fuel cost estimates for CWE during 1981-88 are shown in figure 14 for growth rates of zero and 2 percent. Figure 14 illustrates a situation of declining avoided costs; other CWE calculations indicate a more conventional outcome, with increasing avoided costs over time (35). While the declining cost outcome is by no means certain to occur, it represents a risk to the

Figure 14.—CWE Average Avoided Cost Paths: Baseline Construction~



[a]Calculations based on data supplied to the ICC by CWE.

SOURCE: Edward Kahn and Michael Merritt, *Dispersed Electricity Generation: P/arm/rig and Regulation* (contractor report to OTA, February 1981).

potential investor in cogeneration if economic feasibility depends on sales of excess power to the utility.

New England.–Electric power planning in New England is dominated by the influence of the New England Power Pool (NEPOOL), a regional pool that fully integrates both operations and planning, and by the fragmented nature of the regional utility industry. Most New England utilities are small by national standards, and even the larger New England systems are associations of small companies. Under these conditions it would be impossible for any individual company to achieve the economies of scale offered by large baseload units without undue risk and extra cost. By cooperating in joint venture projects, however, the New England utilities are able to overcome the regional fragmentation and to capture economies of scale. From a regional perspective this has been a significant political achievement (35).

The New England utilities also can purchase capacity from NEPOOL for minimal cost due to the substantial excess capacity on the system (the NEPOOL reserve margin in 1979 was 38.6 percent or 5890 MW above the 15,278 MW winter peakload) (17). A NEPOOL member can meet his capacity responsibility by paying a "deficiency charge" of $22/kW annually to the pool. If the deficiency is above 2 percent, then an additional $14/kW is required for this capacity (57). Even allowing for some escalation in these charges, this is a much lower opportunity cost of capacity than that estimated for potentially capacity short regions such as California. PG&E, for example, is currently offering over $60/kW/yr for short-term capacity contracts in the early 1980's (54).

The principal problem facing NEPOOL and the New England utilities is reducing oil dependence in face of the deteriorating financial condition of, and increasing opposition to, the region's planned nuclear power projects. With the substantial generation reserves in NEPOOL, approval of new projects is more difficult politically. The extreme regulatory risk is that completed projects will not be entered into the rate base on the grounds that they are unnecessary. Such a ruling has recently been made in Missouri (43). Given the relatively large number of jurisdictions in New England, the requirements for political consensus on large-scale projects is severe. Barring such consensus, the economy of scale capacity expansion strategy will fail (35).

Within this planning context, the New England States have adopted a variety of means of implementing PURPA, including two statewide approaches (New Hampshire and Vermont), and one based on the cost differences between a generating utility and its nongenerating subsidiaries (Massachusetts). Although most State regulatory commissions have adopted standard purchase power rates based on each individual utility's capacity mix and operating characteristics, nothing in PURPA precludes statewide or even regional rates if they are appropriate and they further PURPA'S goals of encouraging cogeneration and small power production and promoting the efficient use of utility facilities and resources. Statewide or regional rates may be perceived as advantageous when, as in New England, the operations of utilities are closely integrated so that they effectively form a single power system. In this case, a rate that reflects the avoided costs of the system rather than of individual utilities may provide a better signal of the value of QF power throughout the State or region (38,75).

The New Hampshire PUC established a statewide rate for utility purchases of QF power that uses, as a substitute for individual utility's avoided costs, the operating and maintenance costs of "the most recently constructed and most efficient oil generating station" (Newington) of the State's largest utility (Public Service of New Hampshire) (38). Newington's running costs were deemed to be a "reasonable proxy" for statewide full avoided costs because the other utilities in New Hampshire also rely primarily on oil for electricity generation from units with operating costs at least as high as Newington's.

The New Hampshire purchase rate can be raised to reflect the avoided costs of less efficient units when the load exceeds Newington's capacity or when Newington is not operating. However, the rate cannot be lower. That is, the PUC established a lifetime guaranteed minimum (or "floor") rate for all QFs that begin operation prior to the completion of Seabrook I (a large nuclear unit). The guaranteed minimum encourages oil-displacing QFs to come on-line as soon as possible rather than waiting to see how avoided costs will be affected by the completion of Seabrook, and provides assurance that QFs will have a steady income stream despite the volatility in oil prices. If avoided costs do drop after Seabrook I is completed, QFs that come on-line before then will be subsidized through the guaranteed minimum, but such subsidies are authorized under the New Hampshire Limited Electrical Energy Producers Act, the State's "mini -PURPA." Thus, the primary question surrounding the guaranteed minimum rate is whether future PUCS will be bound by the decision of the present PUC or will discontinue the guarantee (38).

The Vermont Public Service Board based their statewide purchase rate on the estimated avoided costs of NEPOOL, as determined by the average of the actual operating costs of three of the region's most efficient oil-fired baseload plants. The result was similar to that achieved in New Hampshire (see table 19). The Vermont rates will ensure that QFs are not paid more than the cost of oil-fired units in operation at any time, and will enable the State's utilities to readily market QF power either through NEPOOL or elsewhere. The rates are subject to annual revision, but cannot be decreased by more than 10 percent in any year without a strong factual showing that a greater reduction is justified (38). This procedure does not provide as much protection against changes in avoided costs as the New Hampshire guaranteed minimum, but it does limit the rate of decrease if NEPOOL'S avoided costs drop suddenly (e.g., if a new, more efficient baseload plant comes on-line) and it conforms to the traditional ratemaking practice of not subjecting consumers to sudden, drastic changes in rates. As in New Hampshire, the Vermont rate guarantee could result in some subsidization of QFs, but probably will average out over time and thus be within the limits on such subsidies anticipated in the FERC regulations.

A third approach was necessary in Massachusetts to accommodate "all-requirements" contracts among the corporate members of the New England Electric System, a public utility holding company whose subsidiaries include a wholesale generation and transmission company (New England Power) and two retail distribution companies that have "all-requirements" contracts with New England Power (a third distribution sub sidiary purchases at least 75 percent of its electricity needs from New England Power). Under the FERC rules implementing PURPA, avoided cost calculations are supposed to be based on the supplying utility's costs if the power is actually wheeled, and otherwise on the nongenerating utility's cost of purchased power. The Massachusetts Department of Public Utilities (DPU) petitioned FERC for avoided cost rates based on the supplying utility's costs, when the two utilities are corporate affiliates, regardless of whether the power actually is wheeled. DPU argued that such rates would reflect "the true avoided costs of producing that power by the appropriate utility system," rather than an intracorporate transfer price that might be kept artificially low (38). Although FERC has not issued a decision on the DPU petition, this approach does not seem to be precluded by the FERC rules so long as it encourages QF generation. However, if this approach required DPU to look at the reasonableness of the wholesale rates between two corporate affiliates, it could infringe on Federal jurisdiction over such rates under the Federal Power Act (38).

The basis for setting purchase power rates in New England is likely to be tied to oil costs for at least the next 10 years. There is, however, more than one way to reflect oil dependence in PURPA rates. The New Hampshire decision, for example, is based on projected rather than actual oil costs. Presumably such a procedure is intended to correct the accounting lags that occur when actual costs are used and prices are rising rapidly. The California rates discussed above achieve a similar result by indexing rates to the average oil cost in the previous quarter (8,1 O). The California approach will match rates more closely with avoided costs and eliminate the uncertainty of projecting oil prices, but also will result in lower payments.

Given the current excess capacity in New England, any capacity payments made to cogenerators will be limited by NEPOOL deficiency charges. For example, the New Hampshire and Connecticut capacity payments of 5 mills/kWh (the difference between the payments for firm and nonfirm power) correspond roughly to the NEPOOL deficiency charge of $22/kW, where this capacity would be required 4,400 hr/yr ($22/kW / 4,400 hrs = 0.5 cents/kWh) (34).

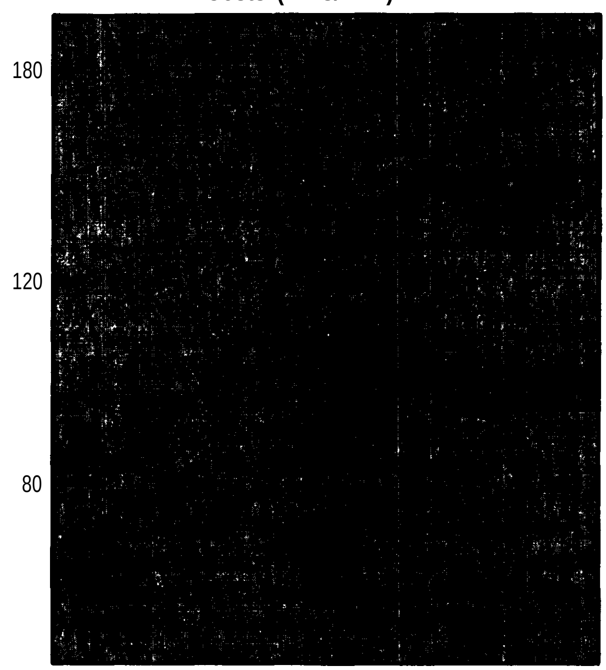
The introduction of QF power into NEPOOL interchanges raises the question of whether NEPOOL billing procedures might reimburse the Vermont utilities on a basis other than full avoided cost. NEPOOL has a complex "split-the-savings" formula that allocates 50 percent of the saving to cover NEPOOL overhead and apportions the remaining 50 percent among utilities based on their volume of business with NEPOOL over a certain period. Due to the relatively low volume of business Vermont utilities do with NEPOOL and the large difference between the utilities' incremental cost and NEPOOL'S decremental cost, in most cases Vermont utilities will not receive the full NEPOOL avoided cost for QF power they supply to the pool. If the utilities must pay QFs the full NEPOOL avoided cost, but recover less than that from the pool, the utilities must either absorb the difference as a loss or pass it on to their ratepayers. The most obvious solution is for NEPOOL to recognize QFs as "sources of power" to utilities under the pool agreement. This is the approach adopted by New England Power in several recent contractual arrangements which identify dispatchability as the main operative distinction: a purchased power resource that can be dispatched by the utility or NEPOOL is a generation resource. Anything else is a negative load (38).

Alternatively, NEPOOL could change its billing practices to accommodate full avoided cost rates by treating QF power as its marginal power rather than mixing it in with other power furnished by a utility. In this case, NEPOOL would, in effect, directly purchase QF power at its full avoided cost and the utility would merely serve as a conduit. Thus, this approach is similar to the FERC provisions for wheeling power through a local utility to a more distant utility.

FUTURE AVOIDED COST PATHS

Given the wide regional variation in the economic and regulatory environment of electric utilities, uniform implementation of PURPA section 210 pricing incentives is unlikely. The pattern of avoided costs over time will depend on existing regional fuel mix and reserve margin, as well as on regulatory policy toward rates and capacity expansion. Figure 15 illustrates several generic paths for average utility avoided costs. A given company will start off on the left-hand side of this figure with its fuel base dominated by oil, coal, or nuclear steam generation. As current construction is completed and fuel costs continue to increase, the fuel base and its value will change. The basis of PURPA payments, avoided costs, also depends on future demand growth. To the extent that supply and demand are out of equilibrium, there will be cost implications for cogenerators and small power producers. One possibility of this kind is the potential for perma-

Figure 15.–Generic Paths for Average Avoided Costs (mills/kWh)



SOURCE: Edward Kahn and Michael Merritt, *Dispersed Electricity Generation: Planning and Regulation* (contractor report to OTA, February 1981).

nent excess capacity; e.g., if State regulators authorize construction of central station plants to displace oil. Resulting reserve margins maybe so great as to preclude PURPA payments for capacity. To examine the potential variety of outcomes, it is-helpful to trace out various pathways through figure 15.

Starting at the upper left with the shortrun marginal cost (SRMC) of oil, several developments are possible. At some point, this shortrun marginal cost curve will intersect the longrun marginal cost (LRMC) curve. If the utility must continue to displace large amounts of oil at this point, the avoided cost will continue to increase at the oil price escalation rate. Two other alternatives are possible. The utility fuel mix may be in equilibrium when SRMC (oil) = LRMC. In this case avoided cost becomes longrun marginal cost, which is likely to rise much more slowly than oil prices. The third alternative is permanent excess capacity. This could occur in any number of ways; all that is required is for construction commitments to exceed long-term demand. In this scenario avoided costs level out over time and converge ultimately to the shortrun marginal cost of coal or nuclear plants (35).

Starting out from a fuel base of excess coal or nuclear capacity, a utility's average avoided costs also will eventually reach equilibrium with longrun marginal cost. This may not occur very smoothly, as figure 15 indicates. At some time excess capacity will be exhausted and new facilities will be necessary. At this point the avoided cost will take a major step upward. Addition of new facilities in such circumstances would pose the practical problem of allocating the longrun marginal cost to capacity and energy for the purpose of designing rate schedules for purchased power (35).

Regulation of Fuel Use

Cogenerators' fuel choice may be influenced by the FUA prohibitions on oil and gas use and by the allocation and pricing rules of NGPA, as well as by environmental requirements and tax incentives (see following sections).

The Fuel Use Act.-A cogenerator may be subject to the FUA prohibitions if it has a fuel heat input rate of 100 million Btu per hour (MMBtu/hr) or greater (or if the combination of units at any one site exceeds 250 MMBtu/hr), and if it comes within the statutory definition of either a powerplant or a major fuel-burning installation. Under FUA, a powerplant includes "any stationary electric generating unit, consisting of a boiler, a gas turbine, or a combined-cycle unit that produces electric power for purposes of sale or exchange," but does not include cogeneration facilities if less than half of the annual electric output is sold or exchanged for resale. A major fuel-burning installation is defined as "a stationary unit consisting of a boiler, gas turbine unit, combined-cycle unit or internal combustion engine." However, the prohibition against the use of oil and gas in new major fuel-burning installations applies only to boilers.

Cogenerators can seek any of four different exemptions from FUA. The one most likely to be used is the cogeneration exemption. If this does not apply, the permanent exemption for the use of a fuel mixture or the temporary exemptions for the future use of synthetic fuels or for public interest considerations may be available.

FUA allows a permanent exemption for cogenerators if the "economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas, or both, are used in such facilities." The Department of Energy (DOE) interprets the phrase "economic and other benefits" to mean that the oil or gas to be consumed by the cogenerator will be less than that which would otherwise be consumed by conventional separate electric and thermal energy systems. Alternatively, if the cogenerator can show that the exemption would be in the public interest (e.g., a technically innovative facility, or one that would help to maintain employment in an urban area), DOE will not require a demonstration of oil/gas savings (72). The regulations to implement the cogeneration exemption are in the process of being revised in order to simplify the procedures for calculating oil and gas savings. Therefore, it is uncertain how difficult it will be to meet the exemption requirements, and thus how FUA will affect the market penetration of cogeneration (67).

Although the permanent exemption for cogeneration is likely to be the preferred route for potential cogenerators subject to the FUA prohibitions, several other exemptions may be applicable in certain circumstances. First, a permanent exemption is available to petitioners who propose to use a mixture of natural gas or petroleum and an alternate fuel. Under this mixtures exemption, the amount of oil or gas to be used cannot exceed the minimum percentage of the total annual Btu heat input of the primary energy source needed to maintain operational reliability of the unit consistent with maintaining a reasonable level of fuel efficiency. Second, a temporary exemption is available to petitioners who plan to use a synthetic fuel (derived from coal or another fuel) by the end of the exemption period. Third, a temporary public interest exemption may be obtained when the petitioner is unable to comply with FUA immediately (but will be able to comply by the end of the exemption). One of the cases where this public interest exemption may be granted is for the use of oil or gas in an existing facility during the ongoing construction of an alternate fuel-fired unit (77).

NGPA grants an exemption from its incremental pricing provisions to qualifying cogeneration facilities under section 201 of PURPA. However, a similar exemption also is available to small industrial boilers and to utilities. Thus, the potentially lower gas prices should not affect the relative competitiveness of gas-fired cogeneration significantly. Moreover, plants burning intrastate gas may not realize any savings because the fuel price is often at the same level as the incremental price. In addition, deregulation could largely remove incremental pricing. These uncertainties mean that NGPA probably will not be a major factor in cogeneration investment decisions (58).

Environmental Regulation

Federal, State, and local requirements for environmental and safety regulation will affect cogeneration, although not to the same degree as they do central station powerplants. The principal effects will result from permitting requirements and from the multiple jurisdictional responsibility for such permitting, which could increase the cost and leadtimes for deployment of cogenerators and impose additional burdens on State agencies.

THE CLEAN AIR ACT

As discussed in chapter 6, cogeneration can have significant impacts on air quality, especially in urban areas. Depending on a cogenerator's size and location, it may be subject to one or more of the Clean Air Act provisions, including new source performance standards (NSPS) and programs for meeting and maintaining the National Ambient Air Quality Standards (NAAQS) in nonattainment and prevention of significant deterioration (PSD) areas.

At present, NSPS exist for two types of sources that might be used for cogeneration, and have been proposed for a third. NSPS have been implemented for electric utility steam units of greater than 250-MMBtu/hr heat input. However, cogeneration facilities in this category are exempt from NSPS if they sell annually less than either 25 MW or one-third of their potential capacity. The other promulgated NSPS is for gas turbines of greater than 10 MMBtu/hr heat input at peakloads, but units in the 10-to 100-MMBtu/hr range are exempt until October 1982 and, in addition, have higher allowable nitrogen oxide (NO_x) emission limits than units above 100 MM Btu/hr. NSPS have been proposed for NO_x emissions from both gasoline and diesel stationary engines. As proposed, they would apply to all diesel engines with greater than 560 cubic inch displacement per cylinder. Finally, the Environmental Protection Agency is considering an NSPS for small fossil fuel boilers. The agency is reportedly considering lower limits in the range of 50 to 100 MMBtu/hr heat input. However, regulations have not yet been proposed. Thus, only the NSPS for gas turbines and the proposed standards for stationary internal combustion engines seem likely to affect cogeneration systems, and then only if they are larger than the prescribed limits.

PSD regulations would apply to fossil fuel boilers of greater than 250-MMBtu/hr heat input that emit more than 100 tons per year (tpy) of any pollutant, and also to any stationary source that emits more than 250 tpy of any pollutant (assuming that controls are in place). A PSD permit is only issued following a review of project plans, and an assessment of project impacts on air quality based on modeling data and up to 1 year of monitoring. These modeling and monitoring requirements can be expensive. For instance, one estimate suggests that the requisite modeling and other PSD requirements add from $35,000 to $80,000 to the installation costs of a 3-MW diesel cogenerator in New York City (1 2).

The application of the nonattainment area requirements to cogenerators also depends on system size; here the trigger is the capability of emitting 100 tpy of a pollutant. Sources with higher emissions must meet the lowest achievable emission rate (LAER), secure emissions offsets, and demonstrate companywide compliance with the Clean Air Act. Smaller sources must use reasonably available control technology and are subject to the general requirement for "reasonable further progress" toward the NAAQS in nonattainment regions.

OTHER FEDERAL REQUIREMENTS

In addition to the potentially extensive permitting requirements for cogenerators under the Clean Air Act, facilities with any cooling water discharges may also need National Pollutant Discharge Elimination System (NPDES) permits under the Clean Water Act. The NPDES permit generally specifies the applicable technological controls or effluent limitations required to achieve the water quality standards for the receiving waters. These permits are only likely to be required for large industrial cogenerators.

Because the only major Federal permit or authorization requirements for cogenerators are those under the Clean Air and Water Acts, they are not likely to be subject to the NEPA process or to the other environmental requirements applicable to central station powerplants. However, operating cogeneration facilities can come under the purview of OSHA, especially with regard to noise standards and the general OSHA recordkeeping requirements. Any restrictions imposed should not be sufficiently burdensome to discourage the deployment of cogenerators.

STATE REGULATION*

State governments are required to implement the Federal permit processes under the Clean Air and Water Acts. States may or may not have other environmental or safety regulations beyond those mandated by Federal law, and State implementation of the Federal requirements may vary widely, depending on their orientation toward regulation as well as on the regional environmental quality. A survey of all State requirements for environmental and safety regulation of cogenerators is beyond the scope of this report. However, some general trends are noted below with a specific comparison of a State with more rigorous requirements (California) and one that has few requirements beyond those mandated by Federal law (Colorado).

Colorado.–The permitting process in Colorado closely tracks the requirements of Federal laws (described in the previous section). One Colorado environmental law deserving some explicit attention is the Colorado Air Quality Control Act (CAQCA), which deviates from the Federal requirements in three ways. First, CAQCA requires essentially all new or modified sources to file an Air Pollution Emission Notice (APEN). Second, all new or modified sources must apply for an emission permit which is required for both nonattainment and PSD areas, and which applies to virtually all fossil fuel facilities except small stationary internal combustion engines and gas burners with less than 750,000-Btu/hr heat input. Third, CAQCA'S significance levels for nonattainment areas are considerably lower than those specified under the Federal program (e.g., 10 tpy of particulate or sulfur dioxide ($S0_2$) rather than the 40 tpy under Federal regulations). Otherwise, the permitting procedures under the Colorado Act are essentially the same as those under the Federal requirements.

The length and complexity of the permitting process for cogeneration in Colorado will depend on the choice of site. Important site-specific factors may include whether Federal or State lands are involved, impacts on surface waters, and ambient air quality levels. Permitting agencies should be contacted simultaneously in order to reduce the time required for licensing and decrease the amount of paperwork.

For this assessment, the Colorado permitting process was applied to two hypothetical cogeneration facilities: a large cogeneration unit consisting of a new coal-fired boiler of 200-MMBtu/hr

*Except where noted otherwise, the discussion in this section is drawn from Energy and Resource Consultants, Inc. (22).

heat input, with steam turbine topping capability, located in an urban area and not selling any excess electricity to the grid; and a small cogeneration unit, represented by a commercial firm's retrofitting a 15-MMBtu/hr diesel engine to supply a maximum of 2-MW electrical output with excess power available to the grid during times of peak demand.

Large Cogeneration Project-Air Permits: Much of the front range area in Colorado is nonattainment for particulate; however, with only minimal control, the 200-MMBtu/hr boiler will not emit over 100 tpy of particulate and thus would not be subject to the strict nonattainment area requirements. Because the entire State is in attainment for SO_2 the plant would require a PSD permit only if it emits more than 250 tpy. Assuming a 70 percent load factor and the use of coal with a 1 percent sulfur content, the uncontrolled SO_2 emissions could approach 1,000 tpy, which would not meet the SO_2 emission rate of less than 1.2 lb/MMBtu for an emission permit under the new fuel burning equipment regulations. Thus, the sponsors for this hypothetical project must choose between achieving a 75-percent reduction in SO_2 emissions or going through the PSD permit process. Note that under the bubble concept for PSD, the source may have some emission credits from the existing boiler.

Large Cogeneration Project– Water Permits: If the boiler's cooling system were to result in discharge to surface waters, a waste discharge permit would be required, as part of the State implementation of the NPDES program. Although existing sources can negotiate a compliance schedule for achieving discharge limits, new sources must meet those limits from the start.

Small Cogeneration Facility: The small cogenerator will have to file an APEN and apply for an emission permit. A 15-MMBtu/hr diesel unit does not qualify as a major source under either the PSD or new source review programs for particulate or SO_2, and at present no NO_x standard has been promulgated for diesels. However, it will be subject to the (as yet undefined) minor source requirements for particulate because it is located in a nonattainment area.

There is little experience with which to judge the impacts of the Colorado permitting process on cogeneration facilities. There are only three cogeneration units in the State, and none is interconnected with the utility grid. Colorado has no special laws, procedures, or exemptions that might suggest a State "policy" toward dispersed generating technologies. Rather the existing regulations derive principally from Federal mandates, which (except for PURPA and the cogeneration exemption under FUA) make no special recognition of dispersed facilities. Thus, the regulatory obstacles to dispersed facilities in Colorado are not severe. Most of the required permits and approvals can be secured in less than 6 months and at modest expense, and, furthermore, have cost and time requirements commensurate with the project size. The only regulatory obstacles would likely be the nonattainment area and PSD requirements for large cogeneration units, and the time the developers will have to spend determining what permits will be necessary for their facilities. At present, there is no central clearinghouse dispensing information on the permitting process.

California.– Regulation of cogeneration in California is complex, but highly organized. The increased complexity arises in two ways: first, due to the large number of agencies and commissions with regulatory responsibility in California; and second, due to the regionalism of major regulatory programs, notably air, water, and coastal zones. For example, the California Air Resources Board (CARB) administers the Clean Air Act in California. Yet 46 local and regional air pollution control districts (APCDS) are responsible for controlling pollution from stationary sources through permitting, enforcement, and the adoption of control standards (often more stringent than those required by CARB). Similarly, although the State Water Resources Control Board administers the Clean Water Act in California, most decisions regarding permits and enforcement are made by nine regional boards and their staffs.

The high degree of organization of the permitting process in California stems from the role played by the Office of Permit Assistance (located in the Governor's Office of Planning and Research), which helps project sponsors identify and meet regulatory requirements. The office screens permit applications and acts as an intermediary between projects and agencies. Another unit with the Office of Planning and Research, the State Clearing House, attempts to coordinate the preparation of, and comments upon, environmental statements—either environmental impact reports under the California Environmental Quality Act (CEQA), or joint statements under CEQA and NEPA.

The permitting process in California centers around the requirement for an environmental impact report (EIR) under CEQA. If the lead agency decides that an EIR is required, one is prepared by that agency in consultation with all other permitting agencies, who must propose definite measures to mitigate any significant impacts identified in the EIR. The entire process is subject to a schedule, defined by statute, such that all decisions on a project must be complete within 18 months of the date the initial application was accepted by the lead agency.

The permitting process in California was analyzed for the same hypothetical large and small cogeneration facilities as discussed for Colorado, above.

Large Cogeneration Project–Air Permits: Every source of air pollution in California requires a two-stage permit. The first stage is an authority to construct based on a review of project plans, and the second stage, following construction, is a permit to operate based on a performance test. The authority to construct and permit to operate require compliance with the emission limitations set by the local APCD. New source review rules also will apply if the source triggers any nonattainment area requirements. Although the basic nonattainment area rules (such as LAER, emission offsets, and companywide compliance) apply across all APCDS, each APCD determines the trigger levels, in terms of pounds of emissions per day, for nonattainment areas. Although conceptually straightforward, the regulations generated by 46 APCDS for several classes of sources and half a dozen individual pollutants are voluminous.

Most APCD trigger levels for new source review in nonattainment areas are more stringent than the Federal requirements. Much of California is in attainment for $S0_2$, but the industrial areas are generally nonattainment for TSP and NO_x. Assuming that the 200-MMBtu/hr coal boiler has NO_x emissions of 0.7 lb/MMBtu, it would emit 140 lb/hr of NO_x, thus triggering the LAER requirement. In addition, an EIR under CEQA may be required. In any event, a final decision by the APCD whether to issue an authority to construct must be made within 1 year.

Large Cogeneration Project–Water Permits: California's waste discharge requirement program predates the Clean Water Act but encompasses the same sources as the NPDES and section 401 programs. For a point source discharge to surface waters, the State waste discharge requirement serves as an NPDES permit. Similarly, requests for a section 401 Water Quality Certificate will result in either a waste discharge requirement if the proposed project would affect water quality, or a letter to the effect that no certificate is required because no impacts are anticipated. All permitting is done by the regional boards in accordance with general standards and criteria developed in their water pollution control plans and, in the case of sources subject to NPDES, using the various Federal technological standards. The waste discharge requirement applies to all point source discharges and additionally to any discharges onto land or to a private pond, and would thus be required for most large cogeneration projects.

Srnall *Cogeneration Facility:* in addition to an authority to construct, the small cogenerator may need to meet nonattainment area requirements for NO_x. A 15-MMBtu/hr heat input cogenerator with emissions of 3.5 lb/MMBtu would result in over so lb/hr of NO_x emitted. These would be offset (under the bubble concept) by the emission level of the diesel engine before the retrofit (if any); so the net increase mayor may not exceed the applicable trigger level.

The differences between environmental regulation in California and Colorado primarily result from the environmental review process mandated by CEQA, and California's aggressive but helpful approach to regulating energy development. The guidelines under CEQA and NEPA for conducting environmental review are quite similar; in fact, many projects will prepare statements acceptable under both guidelines even if CEQA alone is thought to apply. However, the impact of CEQA in California, as compared to NEPA in Colorado, is greater because the environmental review process can be triggered by State, county, and municipal actions, whereas NEPA is triggered only by Federal action. Thus, many more projects may need to prepare environmental reviews in California than in Colorado. This puts more projects into the public arena, but should not result in delays so long as the statutory schedules for permitting are followed.

On the other hand, there are several initiatives in California that encourage cogeneration and may help shorten part of the permitting process. First, new State legislation makes it easier for 50 MW or smaller cogenerators to obtain air quality permits. Under this legislation, cogenerators will receive an emissions credit equal to the emissions that would have come from a powerplant generating the same amount of electricity. In addition, the statute requires CARB and the APCDS to develop a procedure to determine the availability and magnitude of the offsets which result when cogeneration facilities displace powerplants. Thus, in effect, the statute shifts the burden of acquiring nonattainment area offsets from the potential cogenerator to the APCD (1 1).

As a further aid to cogeneration, two special administrative offices have been established to assist prospective cogenerators with regulatory requirements: the Cogeneration Desk of the Office of Permit Assistance, and the Project Evaluation Branch of the Stationary Source Control Division in CARB. Both of these offices are designed to provide assistance in obtaining permits and meeting air quality requirements. Moreover, the Governor's Task Force on Cogeneration (which includes directors from CARB, the Office of Planning and Research, the California Energy Commission, and the public Utilities Commission) is actively seeking ways to encourage cogeneration in the State. Each of these agencies has special personnel available to assist potential cogenerators with all aspects of their project, including legal and technological problems. The experiences of recent California cogeneration projects suggest that environmental and other regulatory requirements are not a major obstacle, especially for smaller facilities. However, potential cogenerators may perceive the permitting process to be onerous, and the principal task for State agencies is likely to be convincing potential cogenerators that the regulatory requirements are not insurmountable.

Financing and Ownership

The basic aspects of financing electric utility capacity additions (reviewed in the previous section) are applicable to cogenerators. A number of other elements special to cogeneration are discussed below, including the tax and financing aspects of cogeneration and considerations related to the different ownership categories: private investors, IOUS, tax-exempt entities, and rural electric cooperatives. *

General Considerations

General considerations related to financing and ownership of cogeneration technologies include the ownership and purchase and sale terms of PURPA (discussed above), the utility financing provisions of the National Energy Conservation Policy Act (NECPA) of 1978 (as amended by the Energy Security Act of 1980), tax incentives of the National Energy Act, the Windfall Profits Tax Act, and the Economic Recovery Tax Act, aspects of project financing and lease relationships, and capital recovery factors.

The most important sections of the Energy Security Act for the purposes of this assessment are contained in title IV—Renewable Energy initiatives, and title V—Solar Energy and Energy Conservation. Title IV establishes incentives for the use of renewable energy resources including wind, solar, ocean, organic wastes, and hydropower; only those provisions related to the use of organic wastes as fuel are applicable to cogenerators. Funding of $10 million in fiscal year 1981 was established to promote renewable energy re-

*Except where noted otherwise, the analysis in this section is from L. W. Bergman & Co. (37).

sources under a 3-year pilot energy efficiency program.

Title V set up a Solar Energy and Energy Conservation Bank in the Department of Housing and Urban Development to make payments to financial institutions in order to reduce either the principal or interest obligations of owners' or tenants' loans for energy conserving improvements to residential, multifamily, agricultural, and commercial buildings. For commercial buildings, the eligible improvements specifically include cogeneration equipment. Direct grants to owners and tenants of residential or multifamily buildings also were authorized but were limited to lower income people. No investment tax credits (only energy credits) were allowed for any projects installed under loans from the Solar Bank, and expenditures were to have been made after January 1, 1980. The bank was intended to continue operations through September 30, 1987, but the fiscal year 1981 budget eliminated all funding for the Bank and its future is, at best, highly uncertain.

The Energy Security Act also amended NECPA to permit utilities to supply, install, and finance conservation improvements or alternate energy systems (including cogenerators) as long as independent contractors and local financial institutions are used and no unfair competitive practices are undertaken by the utility. Utilities are eligible to qualify as lenders and receive subsidies to pass on to customers. Local governments and certain nonprofit organizations are eligible borrowers.

In addition to the regular investment tax credit of 10 percent on most capital investments, several energy incentives have been passed in recent years. Under section 48(1) of the Internal Revenue Code a number of "energy properties" are defined and set aside for special treatment under the investment tax credit (see section on "Taxation, " above). Property is not eligible for these special incentives to the extent that it uses subsidized energy financing (including industrial development bonds), or is used by a tax-exempt organization or governmental unit other than a cooperative. public utility property (that for which the rate of return is fixed by regulation) is excluded from these energy incentives even if it utilizes solar, wind, biomass, or other alternative sources of energy such as synthetic liquid or gaseous fuels derived from coal.

The methods of project finance are particularly appropriate to the financing of distributed electricity generation. project financing looks to the cash flow associated with the project as a source of funds with which to repay the loan, and to the assets of the project as collateral. For successful project financing, a project should be structured with as little recourse as possible to the sponsor, yet with sufficient credit support (through guarantees or undertakings of the sponsor or third party) to satisfy lenders. In addition, a market for the energy output (electrical or thermal) must be assured (preferably through contractual agreements), the property financed must be valuable as collateral, the project must be insured, and all Government approvals must be available (47). With the adoption of PURPA, a source of revenues (rates for power purchases) has become available for small-scale energy project finance.

However, the uncertainty surrounding future rates for power purchases (due to the 1982 Court of Appeals decision discussed previously and the pending Supreme Court review of that decision) has chilled the interest of potential financial backers of cogeneration and small power projects. The revenue stream from utility purchases of cogenerated power is used to secure the project financing. Because the future level of that revenue stream is in doubt, bankers and other investors are reluctant to commit funds until the issue is resolved.

Leasing is a form of project finance because fixed payments are used to amortize capital equipment. Two types of lessors may be involved in project financing: sponsors of a project who lease to the project company, and third-patty leasing companies that are in the finance business. The third-party lessors may have more attractive rates because they utilize the tax benefits of owning the equipment.

The Economic Recovery Tax Act of 1981 substantially changed the tax treatment of leasing to make it very attractive for projects like

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cogeneration. If a cogenerator is unable to take advantage of tax credits (e.g., already has a low tax liability), the tax advantages can be transferred to another party under the safe harbor leasing provisions of ERTA. In essence, these provisions allow the property to be sold for tax purposes only to a corporation in a higher tax bracket. The corporation would give the cogenerator a cash payment (e.g., 25 percent of the property's value) and a note for the remainder of the purchase price, and then lease the equipment back to the cogenerator. Payments due under the note would be matched exactly by the lease payments. Thus, no money actually changes hands after the initial cash payment, and with the exception of the tax difference between lease payments (which are expensed in full) and income from the note (which reflects only its interest component), the transaction is extremely advantageous to both parties (33).

The capital recovery factor, as used in this section, is the cost per kilowatthour which the owner of a cogenerator must receive to recover its capital in a given period of time. Table 20 compares capital recovery factors for four classes of ownership that reflect different income tax structures: a nonutility investor with a 50-percent marginal tax rate; a utility with a 50-percent marginal tax rate; a utility with a 10-percent marginal tax rate that is unable to take advantage of investment tax credits because it already has an excess of such credits; and a nontax-paying entity. In all cases the capital recovery factors are greatest for utilities in the high tax brackets and lowest for nontaxable entities.

One way for an investor to get around high capital recovery factors is to use long-term bond financing. With high leverage, the equity investor is able to recover his investment in a shorter period of time because the bond holder is willing to wait to recover his capital. However, high leverage increases the risk to the equity investor and therefore also increases the required return on equity. Thus, depending on the terms of debt and equity markets, debt financing can make these investments more attractive. It is also important to note that utilities are more comfortable with longer capital payback periods than nonutility equity investors, and that nonprofit entities have a different set of criteria for evaluating investments.

Industrial, Commercial, and Private investor Ownership

Industrial, commercial, vendor, and private ownership share (for the most part) a common tax status and will be discussed together. As noted previously, energy tax credits, coupled with regular investment tax incentives and the PURPA benefits, encourage private firms to enter small power production. The ability to obtain up to 25-percent investment tax credits offers an enormous boost to cash flow early in the project's life. These tax credits can be further magnified, in relation to invested equity, by debt leverage by a factor of 4. PURPA provides a guaranteed market for the power output and it encourages the development of contractual relationships between cogenerators and utilities. In project finance, such contracts are preferable to operating under a tariff structure because contractual relationships are less subject to arbitrary cancellation or alteration of the terms of delivery.

While the incremental investment tax credit for cogeneration is limited (particularly if the cogenerator uses oil or gas), industrial companies have

Table 20.—Capltal Recovery Factors for Cogeneration[a] (cents per year per kllowatthour, In 1980 cents)

	Nonutility investor	High tax rate utility	Low tax rate utility	Nontax paying utility
5 year	3.6cents	4.2cents	3.0cents	2.8cents
10 year	1.6	1.9	1.5	
15 year	1.1	1.2	0.99	0.93
20 year	0.77	0.91	0.74	0.70

[a]1980 capital cost $700/kw; usage 5,000 hrs/yr; depreciation lifetime 20 years.

SOURCE: L. W. Bergman &Co., *Financing and Ownership of Dispersed E/ectriclty Generating Technologies* (contractor report to the Office of Technology Assessment, February 19S1).

some experience with cogeneration and now have the added advantage of PURPA'S purchase and sale requirements. Continued Federal and State Government support of simultaneous purchase and sale at full avoided costs is viewed by some as the single most important factor in overcoming industry indecision to cogenerate (27).

Existing and potential industrial cogeneration participants include industrial parks, integrated pulp and papermills, other process industries (e.g., chemicals, petroleum refining, steel, food processing, textiles), and heavy oil recovery projects (see analysis of industrial cogeneration in ch. 6).

Financing options for industrial cogeneration may be quite varied depending on the size and financial strength of the industrial firm. These options include:

- retained earnings;
- debt issues (including bonds, bank loans, and private placements with insurance companies, pension funds, and similar institutions);
- equity issues;
- joint ventures with other industrial firms (see case 1) or with utilities;
- joint partnership with equity investors such as insurance companies (who may be both lenders and equity investors) and tax shelter syndicates (see case 2);
- leasing arrangements with third parties and vendors, including leveraged leases and safe harbor leases (under ERTA); and
- joint ventures and operating relationships with tax-exempt entities such as municipalities and public power companies. Tax-exempt parties can raise lower cost debt while transferring tax ownership and tax benefits to the private parties.

The incentive to commercial firms to invest in cogeneration will rest heavily on a comparison between the cost of cogenerated electricity (especially the fuel cost) and the price the commercial cogenerator pays for its electricity and heat (comparative basis). Because of their smaller size, commercial firms often do not have financial resources equivalent to those of industrial firms and will be less interested in large scale projects unless they can be cooperatively owned (50).

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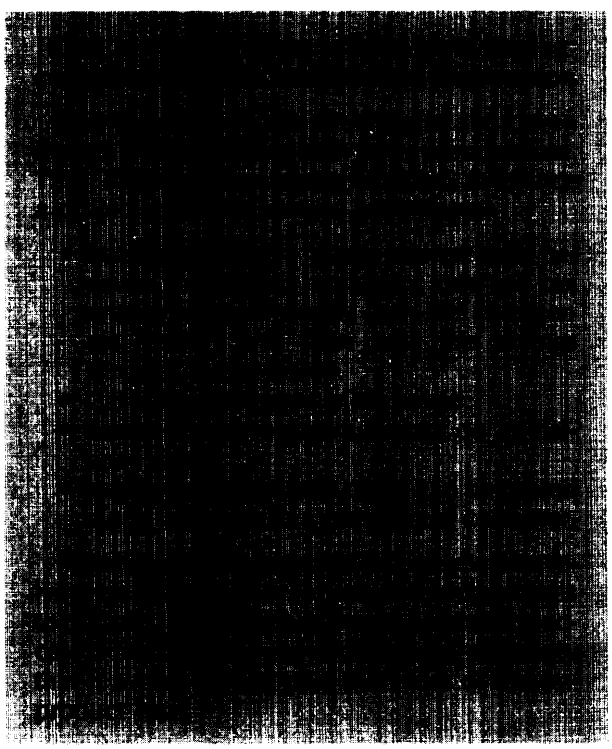
Sources of financing for commercial cogeneration would be similar to those for industrial cogeneration with the following qualifications:

- banks will be a more important source of funds than for industrial firms;
- there will be a greater dependence on outside developers and financial packages;
- joint venture funding will be very useful for regional malls, large buildings, and commercial parks; and
- vendors and third-party lessors will be quite important, particularly for diesel cogeneration (see case 3).

Private investors may be interested in cogeneration because of the unusual tax incentives available and the possibility of an above investment return in unusually promising situations. Joint venture relationships will be most advantageous to private investors, including tax shelter syndicates that provide the equity portion of a leveraged lease and shift tax ownership among the partners. Vendors might provide financing and traditional lease arrangements, particularly in the case of diesel cogenerators, or third parties could take advantage of ERTA's-safe harbor leasing provisions.



Where the owner (industrial, commercial, private investor) is a single entity and no outside joint ventures are involved, project financing via equity, secured or unsecured bank loans, debt, or lease arrangements is straightforvvard. Certain assurances or guarantees will be needed, however, in structuring the financing. These might include:

- contractual arrangements with a utility for electricity purchases under a take-or-pay contract;
- contractual arrangements with the thermal energy purchaser; or
- trustee relationships between the lender and revenue source with excess revenues over fixed charges remitted to the project owner.

Finally, some IOUS may also have financial assistance programs for industrial, commercial, and other private investors in cogeneration. For example, Southern California Gas Co. offers, funding assistance of up to $100,000 or 20 percent of the capital cost (excluding installation labor) for their cogenerating customers. Southern California Gas will co-fund upto$10,000 for the feasibility study (or 10 percent of the study's cost, whichever is less). If the feasibility study is positive, then the company will co-fund up to $40,000 (or 50 percent) of the cost of the design phase of the project, leaving $50,000 for installation and startup (62).

Investor-Owned Utility Ownership

Because almost all electric IOUS are in the business of generating electricity, they are logical potential owners of dispersed generation facilities. The small size, shorter leadtimes, and lower capital requirements of cogeneration systems may provide short-term advantages to utilities in planning for uncertain demand growth. However, the PURPA limitations on utility ownership discourage utility investment in cogeneration. Moreover, most large utilities do not see dispersed generating facilities—including cogeneration—as having the ability to replace future central generating stations, and the low-earned utility rates of return in recent years may not be high enough to encourage utility investment in technologies with uncertain electricity output.

Full (100 percent) utility ownership may be very advantageous if a utility faces revenue losses due to industrial or commercial cogeneration (see ch. 6). For instance, Arkansas Power & Light (AP&L) estimates that if their 35 industrial customers who are prime cogeneration candidates had cogenerated in 1981, AP&L's estimated revenue loss for that year would have been almost $40 million. However, if AP&L developed and owned the cogeneration systems for those 35 industrial customers, not only would they retain that industrial market for electricity, but they would have an additional revenue stream from steam sales—potentially $500 million in the mid-1980's (44). Moreover, if potential industrial or commercial cogenerators are unable to burn coal (e.g., due to space or environmental limitations), or are unwilling to assume the risk of advanced technologies (e.g., gasification), utility ownership with electricity and steam distribution can centralize the burden of using alternate fuels. However, the full incremental ITC is not available for utility-owned cogenerators nor are PURPA benefits available if an IOU owns more than 50 percent of the cogeneration facility. (The potential advantages and disadvantages of full utility ownership are discussed in detail in ch. 7.)

Alternatively, a utility may decide to participate in a joint venture for a cogeneration facility (see cases 4 and 5) in order to structure the ownership in such a way that the investment tax credit and other tax benefits are diverted to the nonutility participants. in addition, financing can be structured so that any debt related to the facility (with the exception of relatively small amounts for working capital) will not appear on the utility's balance sheet. This structuring would be appropriate for utility-financed industrial cogeneration or biomass projects.

Case 4: Joint venture between an industrial corporation and a utility to operate an industrial cogeneration plant.

In this case the industrial corporation owns the facility and leases it to the utility that operates the plant, provides the working capital, and integrates the facility into its entire system. The utility makes lease payments to the industrial owner in the form of cash and steam output but has no formal ownership in the plant. The contractual agreement of the utility to operate the plant is the key to the project. The industrial corporation retains the complete tax benefits. The utility (which may be in a weak financial position) can increase its available capacity without having to raise large capital. Such a scheme is particularly attractive to an IOU that is unable to issue additional long-term debt because of interest coverage covenants in their outstanding bond issues.

Case 5: Joint venture between an industrial company and utility with industrial company supplying 50 percent of funds.

This is an alternative financing for the same project discussed in case 4, but in which the industrial firm is only willing to provide 50 percent of the total capital. Because the utility is not entitled to the incremental energy investment tax credits, it arranges financing for the remaining 50 percent of the facility through a group of investors, who would then have 50 percent individual ownership in the facility. The utility has the same advantages as in case 4 of off-balance-sheet financing and increased capacity. The investors could be a tax shelter syndicate or a variety of other configurations.

Tax= Exempt Entities

The key advantage enjoyed by municipalities in issuing debt is the tax-free status of the interest paid on their obligations, which results in a lower interest rate than that paid on taxable securities. The current spread in yields between new AAA long-term IOU bonds and AAA municipal general obligation bonds is around 375 basis points (100 basis points equals 1 percentage point); between the same utility bonds and revenue bonds the spread is around 330 basis points.

Section 103 of the Internal Revenue Code sets out the provisions for a security to receive tax-exempt interest treatment. Section 103(a) exempts the interest on an obligation of a State or political subdivision (which would include general obligation bonds). Section 103(b), however, denies tax-free status for industrial development bonds (IDBs) except for specific exemptions. In order for IDBs to qualify for tax-exemption, more than 25 percent of the proceeds of an obligation must be used by a nonexempt person for business purposes; a major portion of the principal or interest must be secured by business property; and, in the case of a take-or-pay contract with an electric facility, the contract must be with a nonexempt person and in exchange for payments totaling more than 25 percent of the total output debt service. Moreover, the facilities financed by tax-exempt IDBs must be for general public use and for specified activities including:

- solid waste disposal facilities for the local furnishing of electric energy;
- air or water pollution control facilities; and
- acquisition or development of land for industrial parks, including development for water, sewer, power, or transportation purposes.

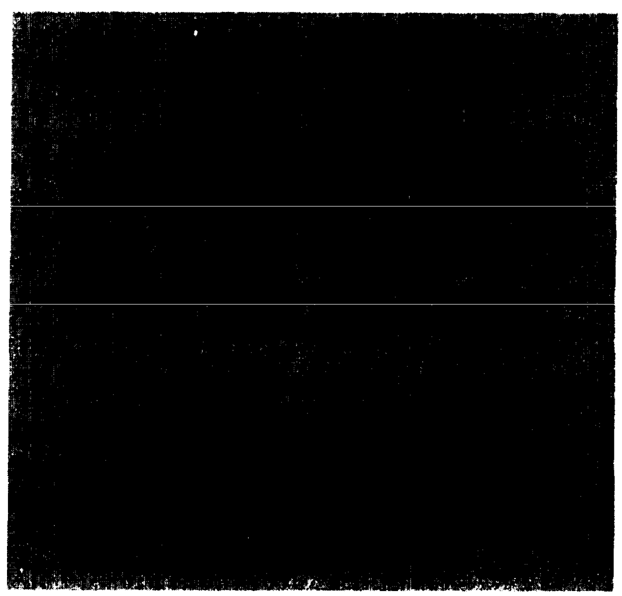
Under the Windfall Profits Tax, solid waste-to-energy facilities are eligible for tax-exempt financing with IDBs if over half of the fuel is derived from solid waste, and the facility is owned by a governmental authority, although year-to-year management contracts with business corporations are allowed.

Perhaps the most important exemption for tax-free financing is the small issue exemption, under which up to $1 million in IDBs (or $10 million provided total capital expenditures do not exceed $10 million) can be issued for any trade or business for the acquisition of land or property subject to depreciation. However, if all of the proceeds of a bond issue are used to finance a project for which an Urban Development Action Grant (UDAG) has been made, then the capital expenditure can be $20 million, of which $10 million must come from sources other than tax-exempt obligations. Renewable energy property is eligible for a special exemption if the bonds used to finance it are general obligations.

Cogeneration is not eligible for special energy tax incentives if over 25-percent fueled from oil or gas. As the technology becomes available, coal-fired cogeneration plants will qualify for special tax incentives and be economically attractive. In the meantime, the best financing strategy for municipalities to foster cogeneration development using available technologies may be to maximize the use of tax-exempt financing (see case 6).

Industrial parks also are an excellent application in which municipalities can foster the development of cogeneration. Tax-exempt IDBs can be issued without limit under a specific exemption for the acquisition of land for industrial parks and its upgrading including water, sewage, drainage, communication, and power facilities prior to use. Cogeneration facilities (including steam distribution lines) presumably would fall into this specific exemption. The requirements encourage joint ventures between the exempt entity and businesses, but the funds must be used by the nonexempt entity in a trade or business and payments secured by an interest in property used in a trade or business. Moreover, some State laws prohibit municipalities from entering into corporate relationships with the private sector, but independent public bonding authorities usually can be established to get around such prohibitions.

Any number of lessor-lessee relationships also are possible between a municipality and a corporation. An important aim of the financing structure would be to allow the corporation to pick up the lo-percent investment tax credit (see case 7).



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Finally, an innovative financing option for municipal utilities and other local government agencies that has attracted a lot of attention in California is the municipal solar utility (MSU). As originally conceived, an MSU would reduce the capital and maintenance costs of solar hot water systems (or other alternative energy or conservation measures) by: 1) only charging customers for their installation; 2) spreading that charge over the lifetime of the system in the monthly electric bills; and 3) providing continued maintenance (28). More recently, the MSU concept has been expanded to include programs *such* as brokerage of different financial and service packages, dedicated deposits of city funds in local banks for low interest alternative energy loans, or technical assistance and other community outreach programs (60).

Rural Electric Cooperative Ownership

Rural electric cooperatives are finding it more difficult to purchase additional electricity from their traditional sources (IOUS and Federal power authorities) and consequently are being forced to build or participate in new generating capacity. Within this context, dispersed facilities (including cogeneration) may be advantageous due to the shorter construction times, greater planning flexibility, and lower capital costs. In addition, alternate energy projects are more readily financed at favorable terms. Such financing includes 35-year loans for feasibility studies under the REA insured loan program, and is designed to help overcome the lack of engineering expertise and other resource constraints faced by small distribution co-ops that wish to add generating capacity. As with other electric utilities, co-ops will prefer projects that provide most of their additional capacity during peak demand periods and whose electricity output is not intermittent (e.g., biomass, hydroelectric, and industrial cogeneration projects).

For a project with IOO-percent co-op ownership, all the benefits accrue to the cooperative's members (e.g., no taxes are paid and no profits are distributed to investors). Capital is raised through an REA guaranteed loan, which means that the cost of capital will be lower than for a private investor because the U.S. Government has guaranteed the loan. Other financing options for cooperatives include joint ventures with local governments or with industrial concerns (see case 8).

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