Chapter 1

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INTRODUCTION

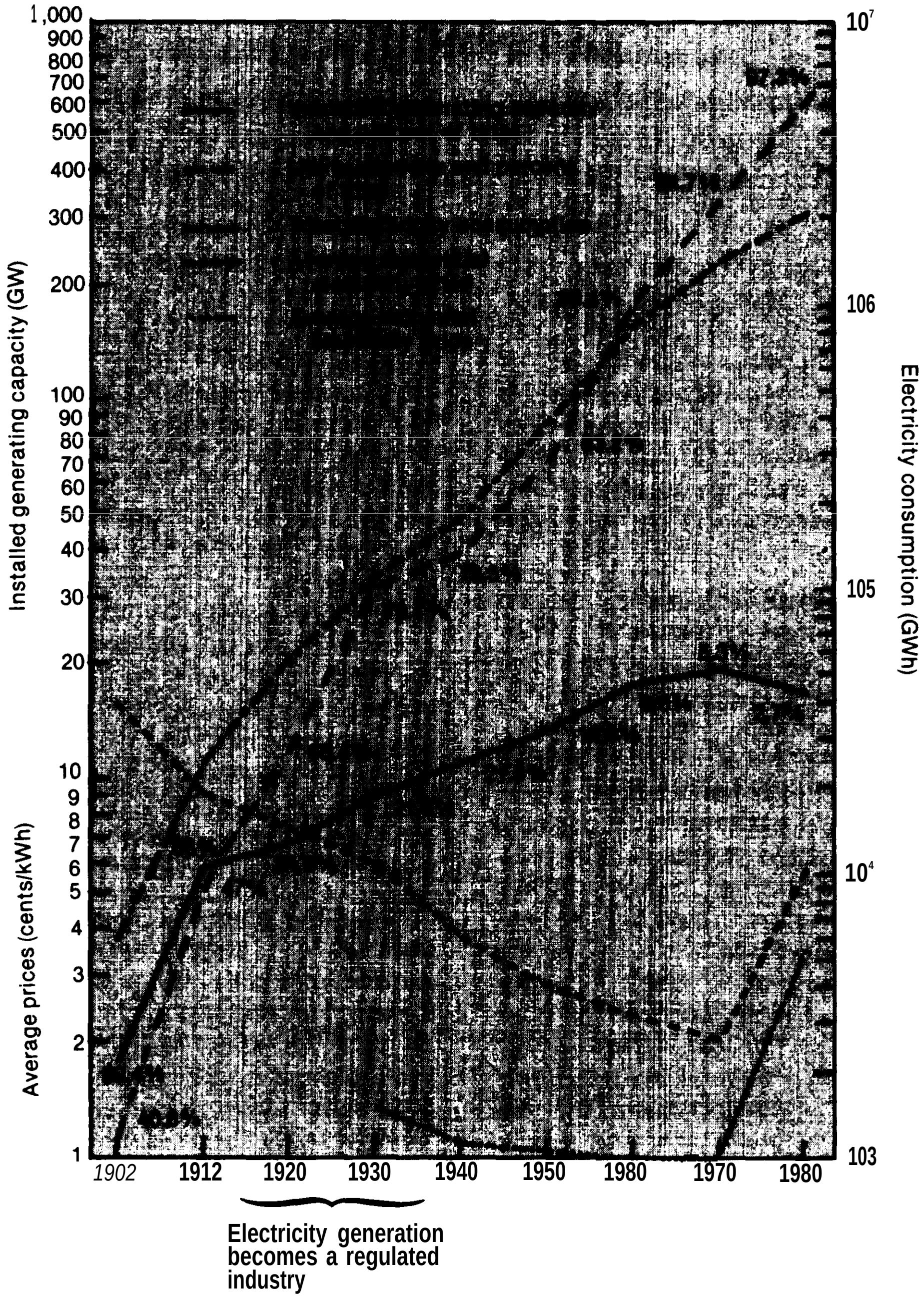
A major focus of the current energy debate is how to meet the future demand for electricity while reducing the Nation's dependence on imported oil. Conservation in buildings and industry, and conversion of utility central station capacity to alternate fuels will play a major role in reducing oil use in these sectors. But cost-effective conservation measures can only go so far, and the industrial and commercial sectors ultimately will have to seek alternative sources of energy. Moreover, electric utilities may face financial, environmental, or other constraints on the conversion of their existing capacity to fuels other than oil, or on the construction of new alternate-fueled capacity.

A wide range of alternate fuels and conversion technologies have been proposed for the industrial, commercial, and electric utility sectors. One of the most promising commercially available technologies is cogeneration. Cogeneration systems produce both electrical (or mechanical) energy and thermal energy from the same primary energy source. Cogeneration systems recapture otherwise wasted thermal energy, usually from a heat engine producing electric power (i.e., a steam or combustion turbine or diesel engine), and use it for applications such as space conditioning, industrial process needs, or water heating, or use it as an energy source for another system component. This "cascading" of energy use is what distinguishes cogeneration systems from conventional separate electric and thermal energy systems (e.g., a powerplant and a low-pressure boiler), and from simple heat recovery strategies. Thus, conventional energy systems supply either electricity or thermal energy while a cogeneration system produces both. The automobile engine is a familiar cogeneration system as it provides mechanical shaft power to move the car, produces electric power with the alternator to run the electrical system, and uses the engine's otherwise wasted heat to provide comfort conditioning in the winter.

Cogeneration is an old and proven practice. Between the late 1880's and early 1900's, oil- and gas-fired cogeneration technologies were increasingly used throughout Europe and the United States. In 1900, over 59 percent of total U.S. electric generating capacity was located at industrial sites (not necessarily cogenerators) (see fig. 1). Because electric utility service during this period was limited in availability, unreliable, unregulated, and usually expensive, this onsite generation provided a cheaper and more reliable source of power. However, as the demand for electricity increased rapidly and reliable electric service was extended to more and more areas in the early 1900's, as the price of utility-generated electricity declined, and as electric generation became a regulated activity, industry gradually began to shift away from generating electric energy onsite. By 1950, onsite industrial generating capacity accounted for only about 17 percent of total U.S. capacity, and by 1980 this figure had declined to about 3 percent. At the same time, cogeneration's technical potential (the number of sites with a thermal load suitable for cogeneration) has been increasing steadily.

There has been a resurgence of interest in recent years in cogeneration for industrial sites, commercial buildings, and rural applications. A cogenerator could provide enough thermal energy to meet many types of industrial process needs, or to supply space heating and cooling and water heating for a variety of different commercial applications, while supplying significant amounts of electricity to the utility grid. Because cogenerators produce two forms of energy in one process, they will provide substantial energy savings relative to conventional separate electric and thermal energy technologies. Because cogenerators can be built in small unit size (less than 1 megawatt (MW)) and at relatively low capital cost, they could alleviate many of the current problems faced by electric utilities, including the difficulty of siting new generating capacity and the

Figure l.—Historical Overview of Electricity.Generating Capacity, Consumption, and Price, 190240



SOURCE: Office of Technology Assessment from Edison Electric Institute, Statistical *Yearbook of the Electric* Utility Industry: 1980(Washington, D.C.: Edison Electric Institute, 1961); Historical *Statistics of the United States, Co.-lonial Times to* 1970: *Part* 2 (Washington, D.C.: U.S. Government Printing Off Ice, 1976).

high interest costs currently associated with financing large powerplants. The small size of cogeneration systems also may be attractive as a form of insurance against short-term fluctuations in electricity demand growth (in lieu of the costly overbuilding of central station powerplants). However, if cogenerators are not designed and sited carefully, and if their operation is not coordinated with that of the electric utilities, they also have the potential to increase oil consumption, contribute to air quality problems in urban areas, and increase the cost of electric power.

Congress has expressed considerable interest in decentralized energy systems and in cogeneration. Cogeneration is a major issue in the National Energy Act of 1978, parts of which were designed to remove existing regulatory and institutional ob stacles to cogeneration and to provide economic incentives for its implementation. In addition, the House Energy and Commerce Committee, the House Science and Technology Committee, and the Senate Energy and Natural Resources Committee have held hearings on cogeneration, and several committees in both Houses of Congress have held hearings on the general concept of decentralized energy systems.

The House Committee on Banking, Finance, and Urban Affairs requested that OTA undertake a study of small electricity-generating equipment. The request expressed concern that "considerations of energy policy have not taken adequately into account the possibilities for decentralizing part of America's electrical generating capabilities by distributing them within urban and other communities." Citing the financial problems currently faced by electric utilities and the availability of a wide range of new generating technologies, the committee requested "a careful examination of the role that small generating equipment could play and the economic, environmental, social, political, and institutional prerequisites and implications of greater utilization of such equipmerit. " In 1981, the House Energy and Commerce, and Science and Technology Committees wrote letters to OTA reaffirming congressional interest in a study that would provide a better understanding of the economic, regulatory, and institutional barriers to the development of cogeneration and small power production by utilities, industries, and businesses.

In response to these requests, OTA undertook this assessment of cogeneration technologies. The assessment was designed to answer four general questions:

1. Under what circumstances are cogeneration technologies likely to be economically attractive and on what scale, and what is the potential for new technologies in the future?
2. How much electric power is economically or technically feasible for cogeneration to contribute to the Nation's energy supply?
3. What are the economic, environmental, social, and institutional impacts of cogeneration?
4. What policy measures would accelerate or retard the use of cogeneration systems?

In order to answer these questions, this report reviews the features of the Nation's energy picture (e.g., supply of and demand for fuels and electricity) and of the electric power industry that may affect decisions to invest in cogeneration systems; describes the major technologies suitable for cogeneration applications; analyzes the impacts of industrial and commercial cogeneration on utility planning and operations, on fuel use, and on environmental quality; and discusses the policy issues arising from existing legislation or regulations related to cogeneration. Because electric utilities are most likely to be affected strongly by onsite generation, the technical, institutional, and policy analyses focus on the role of utilities in such generation, and its effects on their future planning and operations.

The main focus of the report is the use of cogeneration equipment in the industrial and commercial sectors; promising rural applications are discussed briefly. The cogeneration technologies addressed in detail include steam and combustion turbine topping cycle equipment as well as combined-cycle systems, diesel topping cycles, Rankine bottoming cycles, Stirling engines, and fuel cells. Other small power production technologies (wind, solar electric, small-scale hydro) originally were included in the scope of this study. However, OTA found that reliable data on these technologies' potential to produce electricity are not yet available. Moreover, the inclusion of four separate types of technologies made the scope of the study too broad. Therefore, analysis of these small power production systems has been reserved for a subsequent OTA assessment of electricity supply and demand in general.

Volume I of this report is organized as follows:

- chapter 2 highlights the central issues surrounding cogeneration and summarizes OTA'S findings on those issues;
- chapter 3 reviews the context in which cogenerators will operate, including the national energy situation, current electric utility operations, and the regulation and financing of cogeneration systems;
- chapter 4 presents an overview of the cogeneration technologies, including their operating and fuel use characteristics, projected costs, and requirements for interconnection with the utility grid;
- chapters analyzes the opportunities for cogeneration in industry, commercial buildings, and rural areas;
- chapter 6 assesses the impacts of cogeneration on electric utilities' planning and operations and on the environment, as well as on general economic and institutional factors such as capital requirements, employment, and the decentralization of energy supply; and
- chapter 7 discusses policy considerations for the use of cogeneration technologies.

The appendices to volume I include a description of the model used to analyze commercial cogeneration (ch. 5) and of the methods used to calculate emissions balances for the air quality analysis in chapter *6,* as well as a glossary of terms and a list of abbreviations used in the report. Selected reports by contractors in support of OTA'S assessment are presented in volume II.

COGENERATION TECHNOLOGIES

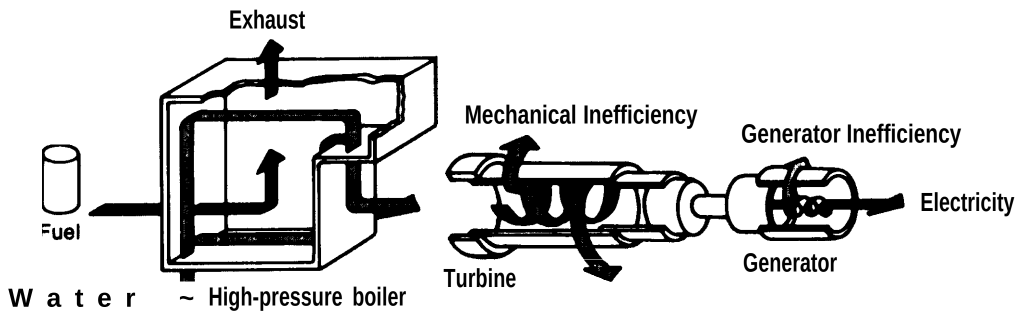
The principal technical advantage of cogeneration systems is their ability to improve the efficiency of fuel use. A cogeneration facility, in producing both electric and thermal energy, usually consumes more fuel than is required to produce either form of energy alone. However, the total fuel required to produce both electric and thermal energy in a cogeneration system is less than the total fuel required to produce the same amount of power and heat in separate systems. Relative efficiencies are portrayed graphically in figure 2 for an oil-fired steam electric plant, an oil burning process steam system, and an oil-fired steam turbine cogenerator with a high-pressure boiler. It should be noted, that despite its relative efficiency in fuel use, the fuel saved in cogeneration will not always be oil. Only if a cogenerator replaces separate technologies that burn oil and would continue to do so for most of the useful life of the cogenerator, will the fuel saved with cogeneration be oil.

A wide range of technologies can be used to cogenerate electric and thermal energy. Commercially available technologies are steam turbines, open-cycle combustion turbines, combined-cycle systems, diesels, and steam Rankine bottoming cycles. Advanced technologies that may become commercially available within the nexts to 1s years include closed-cycle combustion turbines, organic Rankine bottoming cycles, fuel cells, and Stirling engines. Solar cogenerators (e.g., the therm ionic topping system) also are under development, but are not discussed in this report.

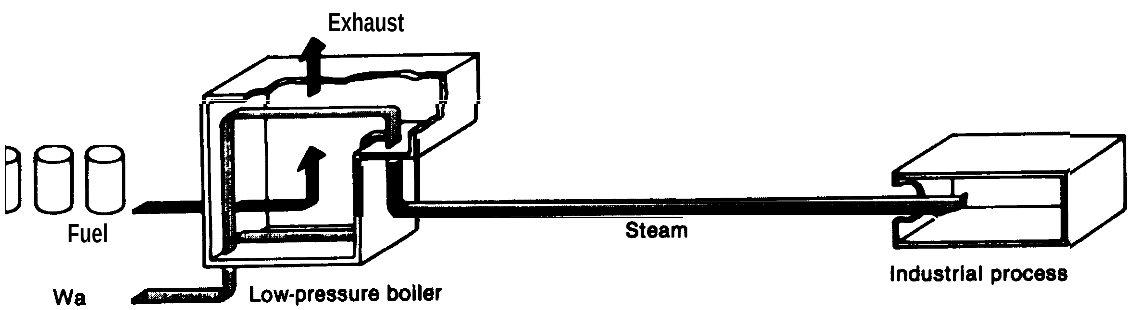
Cogeneration technologies are classified either as "topping" or "bottoming" systems, depending on whether electric or thermal energy is produced first. in a topping system–the most common cogeneration mode—electricity is produced first, and then the remaining thermal energy is used for such purposes as industrial processes, space heating and cooling, water heating, or even the production of more electricity. Topping systems would form the basis for residential/commercial, rural/agricultural, and most industrial cogeneration applications. In a bottoming system,

Figure 2.—Conventionai Eiectricai and Process Steam System Compared With a Cogeneratlon System

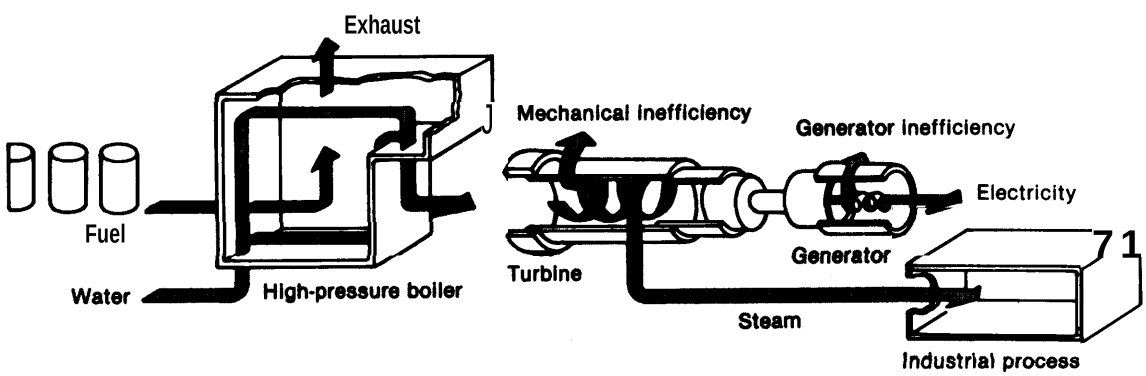
(A) Conventional electrical generating system requires the equivalent of 1 barrel of oil to Produce 800 kWh electricity



(B) Conventional process-steam system requires the equivalent of 2 1/4% barrels of oil to produce 8,500 lb of prooess steam



(C) Cogeneration system requires the equivalent of 2 3/4% barrels of oil to generate the same amount of energy as systems A and B



SOURCE: Resource Planning Associates, *Cogerreration.' Techn/ca/ Concepts, Trends, Prospects* (Washington, D. C.: U.S. Department of Energy, DOE-FFU-1703, 1978).

high-temperature thermal energy is produced first for applications such as steel reheat furnaces, glass kilns, or aluminum remelt furnaces. Heat is extracted from the hot exhaust waste stream and transferred to a fluid (generally through a waste heat recovery boiler), which is then vaporized by the waste heat to drive a turbine that produces electricity. The primary advantage of bottoming cycles is that they produce electricity with waste heat (i.e., no fuel is consumed beyond that needed in the industrial process), but their use is limited to industries that need high-temperature heat.

Cogeneration technologies vary widely in their cost, energy output, efficiency, and other characteristics (see table 1). The choice of cogeneration equipment for a particular application will depend on a number of considerations, including:

- *Thermal* energy needs: How much heat/ steam is needed onsite and at what temperature and pressure?
- Electric energy needs: How much electricity is needed onsite and how much is to be distributed to the grid?
- *Operating characteristics:* Will the cogenerator be operating all the time or only at certain times of the day or year?
- *Physical site /imitations:* How much space is available for the cogenerator and its auxiliary equipment (e.g., fuel handling and storage)?
- *Air quality considerations:* What are the emission limitations onsite and can they be accommodated through pollution controls and stack height?
- *Fuel availabillty:* Which fuels are readily available, and will the cogenerator displace oil or some other fuel?
- *Energy costs:* What are the relative prices of fuels for cogeneration (primarily natural gas in the near term, but also coal, biomass, and synthetic fuels) and of retail electricity?
- *Capital availability and costs:* Will the cogenerator be able to find attractive financ-

Table I.—Summary of Cogeneration Technologies

Technology	Unit size	Fuels used (present/possibie in future)	Average annual availability (percent)	Full-load electric efficiency (percent)	Part-load (at 50% load) electric efficiency (percent)	Total heat rate (Btu/kWh)	Net heat rate (Btu/kWh)	Electricity-to-steam ratio (kWh/MMBtu)
A. Steam turbine topping	500 kW-100 MW	Natural gas, distillate, residual, coal, wood, solid waste/coal- or bio-mass-derived gases and liquids.	90-95	14-28	12-25	12,200-24,000	4,5006,000	30-75
B. Open-cycle gas turbine topping	100 kW-100 MW	Naturai gas, distillate, treatad residual/coal- or biomass-derived gases and liquids.	90-95	24-35	19-29	9,750-14,200	5,500-6,500	140-225
C. Ciosed-cycle gas turbine topping	500 kW-100 MW	Externally fired—can use most fuels.	90-95	30-35	30-35	9,750-11,400	5,400-6,500	150-230
D. Combined gas turbine/steem turbine topping	4 MW-1OO MW	Naturai gas, distillate, residual/coal- or biomass-derived gases and liquids,	77-65	34-40	25-30	8,000-10,000	5,000-6,000	175-320
E. Diesel topping	75 kW-30 MW	Natural gas, distillate, treated residual/coal- or biomass-derived gases and liquids, slurry or powdered coals.	60-90	33-40	32-39	8,300-10,300	6,000-7,500	350-700
F. Rankine cycle bottoming:								
Steam	500 kW-10 MW	Waste heat.	90	10-20	Comparable to full load	17,000-34,100	NA	NA
Organic	2 kW-2 MW	Waste heat.	60-90	10-20	Comparable to full load	17,000-34,100	NA	NA
G. Fuel cell topping	40 kW-25 MW	Hydrogen, distillate/coal.	90-92	37-45	37-45	7,500-9,300	4,300-5,500	240-300
H, Stirling engine topping	3-100 kW (expect 1.5 MW by 1990)	Externally fired—can use most fuels.	Not known—expected to be similar to gas turbines and diesels.	35-41	34-40	8,300-9,750	5,500-6,5C4J	340-500

Table 1 .—Summary of Cogeneration Technologies-continued

Technology	Total installed cost ($/kW)[a]	Operation and maintenance cost: Annual fixed cost ($/kW)	Operation and maintenance cost: Variable cost (millions/kWh)	Construction leadtime (Years)b	Expected lifetime (years)	Commercial status	Cogeneration applicabiiity
A. Steam turbine topping	550-1,600	1,6-11.5	3.0-8.8	1-3	25-35	Mature technology —commercially available in large quantities.	This is the most commonly used cogeneratlon technology. Generally used in industry and utility applications. Best suited for where electric/thermal ratio is low.
B. Open-cycle gas turbine topping	320-700	0.29-0.34	2.5-3.0	0.75-2	20 natural gas 15 distillate	Mature technology —commercially available in large quantities.	Potential for use in residential, commercial, and industrial sectors if fuel is available and cost effective.
C. Closed-cycle gas turbine topping	450-900	5 percent of acquisition cost per year	Included in fixed cost	2-5	20	Not commercial In the United States; is well developed in several European countries.	Best suited to larger scale utility and Industrial applications. Potential for coal use is excellent.
D. Combined gas turbine/steam turbine topping	430-800	5.0-5.5	3.0-5.1	2-3	15-25	Commercially available; advanced systems by 1985.	Most attractive where power requirements are high and process heat requirements are lower, Used in large industrial applications such as steel, chemical, and petroleum refining industries.
E. Diesel topping	350-800	6.0-8.0	5.0-10.0	0.75-2.5	15-25	Mature technology —commercially available in large quantities.	Reliable and available, can be used in hospitals, apartment complexes, shopping centers, hotels, industrial centers if fuel is available and cost effective, and if can meet environmental requirements,
F. Rankine cycle bottoming:							
Steam	550-1,100	1,6	3.7-6.9	1-3	20	Commercially available.	Industrial and utility use almost exclusively. Although efficiency is low, since it runs on waste heat no additional fuel is consumed. Can reduce overall fuel use.
Organic	800-1,500	2.8	4,9-7.5	1-2	20	Some units are commercially available but technology is still in its infancy.	Same benefits/limitations as steam Rankine bottoming except that it can use lower-grade waste heat. Organic Rankine bottoming is one of the few engines that can use waste heat in the 200° 600°F range,
G. Fuel cell topping	520-840C	0.26-3,3	1.0-3.0	1-2	10-15	Still in development and experimental stage. phosphoric acid expected by 1985, moiten carbonate by 1990.	Modular nature, low emissions, excellent part-load characteristics allow for utility load foliowing as well as applications in commercial and industrial sectors.
H. Stirling engine topping	420-960[c]	5.0	8.0	2-5	20	Reasonably mature technology up to 100-kW capacity but not readily available. Larger sizes being developed.	High efficiency and fuel flexibility contribute to a large range of applications. Couid be used in residential, commercial, and industrial applications. Industrial use depends on development of large Stirling engines,

"NA" means not applicable.

[a]1980 dollars,

[b]Depends on system size and heat source.

[c]Cost estimates assume successful development and Commercial scaie production, and are not guaranteed,

SOURCE: Office of Technology Assessment from material in ch. 4, ing, or will investments in process improvements have priority for available capital?

At present, significant uncertainties about the types of cogeneration technologies that will be installed and their location, costs, and operating characteristics, and about general financial and economic conditions make it difficult to analyze the market potential for cogeneration or its impacts on electric utilities, fuel use, and the environment. However, general trends in the national energy, electric utility, and policy context in which cogenerators would be deployed can be discerned, and analyses of these trends can be used to evaluate existing policy incentives.

THE POTENTIAL FOR COGENERATION

Cogeneration could have a very large technical potential in the United States–perhaps as much as 200 gigawatts (GW) of electrical capacity by 2000 in the industrial sector alone, with a much lower potential (3 to 5 GW) in the commercial, residential, and agricultural sectors. (Total U.S. installed generating capacity in 1980 was approximately 619 GW.) However, cogeneration's market potential (the amount of cogeneration capacity that might be considered sufficiently economic for an investment to be made) will be much smaller than this for several reasons.

First, cogeneration investments will have to compete with conservation in industries and buildings. Conservation investments usually are less costly than cogeneration and have a shorter payback period, and thus are likely to receive priority over cogeneration in most cases. As a result of conservation measures, thermal energy demand is likely to grow much more slowly than it has in the past (some sources project a zero or negative rate of growth in industrial thermal demand through 2000), and could present a declining opportunity for cogeneration.

In addition, cogeneration will compete in the long term (beyond 1990) with electricity supplied by coal, nuclear, hydroelectric, and other types of alternate-fueled electric utility generating capacity. Some cogeneration applications may not be economically competitive where utilities have relatively low retail electricity rates or are planning to replace existing powerplants with ones that will generate electricity more economically (e.g., replacing intermediate-load oil-fired generators with baseload coal plants).

Cogeneration's market potential also will be limited by the inability of most technologies—especially smaller scale systems—to use fuels other than oil or natural gas. At present, only steam turbine cogenerators can accommodate solid fuels. Advanced technologies now under development will have greater fuel flexibility, as well as better fuel efficiency and lower emissions. In addition, advanced fuel combustion or conversion systems such as fluidized beds and gasifiers can be used to improve the fuel flexibility of existing cogeneration technologies. More development is needed, however, to make these technologies commercially attractive, and they are not likely to contribute significantly for 5 to 10 years.

Cogeneration's ability to supply electricity to the utility grid also will affect its market potential. Under the Public Utility Regulatory Policies Act of 1978 (PURPA), economic and regulatory incentives are offered to cogenerated power that reduces utility costs for capacity, energy, or transmission and distribution, or that contributes to power supply or load reduction during daily or seasonal peak demands. These incentives are reflected in the price that utilities must pay for power purchased from a cogenerator, which is determined by a utility's incremental costs, or the costs avoided in not generating and distributing the power itself or purchasing bulk power from the grid. In many parts of the country, shortrun avoided energy costs will be based on the price the utility pays for oil or natural gas, and capacity costs on the operating cost of a peakload powerplant (e.g., a combustion turbine). In these cases, the greater efficiency of cogeneration systems—even those burning distillate oil or natural gas–often can make cogeneration the economically preferable means of generating electricity. However, if the utility relies primarily on coal or nuclear fuel and has excess capacity, then the shortrun avoided energy cost (determined by offsetting coal or nuclear fuel) would be much lower and there may be no shortrun avoided capacity cost. In these cases, shortrun avoided cost payments may not be sufficient to make cogeneration an attractive investment. Longrun avoided costs would be based on a utility's resource plan, and would raise the issue noted above of competition with coal and other non premium fuels.

Furthermore, the choice of technology will affect a cogenerator's ability to supply power to the grid. In general, technologies with a high ratio of electricity-to-steam production (E/S ratio) will be favored when onsite electric power needs are large or when power is to be exported offsite; these include diesels, combustion turbines, and combined-cycle systems. At present, however, the high E/S ratio systems can only burn oil or natural gas. Steam turbines, the only commercially available technology that can burn solid fuels directly, have a relatively low E/S ratio. For example, a large industrial installation that uses 500,000 lb/hr of steam would cogenerate 30 to 40 MW of electricity with steam turbines, and 120 to 150 MW with combustion turbines. Therefore, where onsite electricity needs are high, or the project's economic feasibility depends on supplying electricity to the grid, a technology with a higher E/S ratio (e.g combustion turbines, diesels, combined cycles) would be favored, but could not use fuels other than oil/gas in the short term.

COGENERATION OPPORTUNITIES

Although the factors discussed above make cogeneration's overall market potential highly uncertain, it is possible to identify promising cogeneration opportunities in the industrial and commercial sectors and in rural areas.

Industrial Cogeneration

Today, industrial cogeneration has an estimated installed capacity of 14,858 MW (see table 2). * An additional 3,300 MW is reported to be in the planning stages or under construction. The largest number of industrial cogenerators are in the pulp and paper industry, which has large amounts of burnable wastes (process wastes, bark, scraps, and forestry residues unsuitable for pulp) that can be used to fuel cogenerators. For at least two decades this industry has considered electricity generation to be an integral part of its production process and new pulp and paper plants are likely candidates for cogeneration.

The chemical industry uses about as much steam annually as the pulp and paper industry and historically has ranked third in industrial cogeneration capacity. Chemical plants also will represent a promising source of new cogenerators. Conservation opportunities, however, will strongly dampen growth in steam demand if not cause it to decline.

Another major cogenerator is the steel industry, because the off-gases from the open-hearth steelmaking process provide a ready source of fuel to produce steam for driving blast furnace air compressors and other uses. But new cogener-

*A more recent estimate arrives at a total of about 9,100 MW (5). No breakdown by SIC code is given, however, but we assume the distribution would be similar to that given in table 2.

Table 2.–installed Industrial Cogeneration Capacity

Sector (SIC code)	Capacity (MW)	Capacity (percent)	Number of plants	Plants (percent)
Food (20)	398	3	42	11
Pulp and paper (26)	4,246	29	136	37
Chemicals (28)	3,438	23	62	17
Petroleum refining (29)	1,244	8	24	6
Primary metals (33)	3,589	24	39	11
Other	1,943	13	68	18
Total	14,858		371	

SOURCE: General Energy Associates, *Industrial Cogeneration Potential: Targeting of Opportunities at the Plant Site* (Waahington, D. C.: U.S. Department of Energy, 1982).

ation capacity is not likely to be installed in this industry because new steel mills probably will be minimills that use electric arcs and have little or no thermal demand. However, if a market for the thermal output could be found, an electric arc minim ill could use the cogenerated electricity and sell the heat/steam.

petroleum refining also is well suited to cogeneration, but significant new refinery capacity is not expected to be built in the near future, except in connection with heavy oil recovery in California. However, some cogeneration capacity could be installed when existing refineries are upgraded.

Finally, the food processing industry currently has a small amount of cogeneration capacity which could more than double by 1990. Here the primary limit on the cogeneration potential is the low thermal load factor that results from the seasonal nature of the steam demand.

Commercial Building Cogeneration

Cogeneration in commercial buildings has a much smaller potential for growth than industrial cogeneration, primarily due to the low thermal load factors in those buildings. Additional constraints on commercial building cogeneration opportunities include the difficulty of handling and storing solid fuels (coal, biomass) in and around buildings; competition with conservation for energy investment funds, and with coal or other baseload capacity additions for economic electricity generation; and the special air quality considerations in urban areas.

The disadvantages presented by the low thermal load factors in commercial buildings can be overcome to some extent by undersizing the cogenerator and operating it at a high capacity factor to meet the baseload thermal needs, and using conventional thermal conversion systems to supplement the cogenerator's output. Alternatively, several buildings could share a cogenerator and use the diversity in their energy demand to improve the thermal load factor.

Moreover, commercial building cogeneration fueled with natural gas may have a promising market in the near term (up to 1990), especially where rates for utility purchases of cogenerated power are based on the price of oil-fired electricity generation and utilities have substantial amounts of oil burning capacity. In these cases, cogeneration can allow rapid development of capacity to meet new electricity demand and/or reduce utility oil use. However, as noted previously, in the long term, cogeneration will have to compete economically with coal and other alternate-fueled utility capacity.

The probable low market penetration of commercial sector cogeneration means that it usually will have a low potential for displacing the fuel used by utility generating capacity. However, where electricity prices are high or utility capacity additions are limited, cogeneration may have a greater market potential and could displace utility intermediate oil or gas capacity. If both the cogenerator and the capacity it displaces use oil, the result usually would be a decrease in utility use of residual fuel oil and a corresponding increase in distillate use by commercial cogenerators, but an overall reduction in total oil use. Relatively small systems with good part-load characteristics (e.g., diesels and spark-ignition engines) are likely to be favored in urban residential/commercial applications where there are physical site limitations and low capacity factors, and these systems are limited to the use of oil or natural gas in the near term.

In summary, OTA found that commercial building cogeneration would be economically attractive where there is a moderate rate of growth in electricity demand (2 percent or more annually), where electric utilities are caught in a capacity shortfall, or where the utility has a high percentage of oil-fired capacity; where there is a high heating demand (about 6,000 heating degree days per year); and where cogenerators can use a fuel that is significantly less costly than oil. However, even if these advantages are available, cogeneration's competitiveness in the commercial sector will be subject to the same limiting factors as in the industrial sector—competition with conservation measures that have a lower capital cost and shorter payback period, the ability to supply significant amounts of power to the grid, and economic and regulatory uncertainties.

Rural Cogeneration Opportunities

Rural cogeneration opportunities arise where there are existing small community powerplants that could recover and market their waste heat, and/or where alternate fuels (such as biomass) are readily available. Promising rural cogeneration applications include producing ethanol, drying crops or wood, and heating greenhouses, animal shelters, or homes.

A large number of small rural powerplants are standing idle due to the high cost of premium fuels. Generally these are dual-fuel engines burning natural gas plus small amounts of fuel oil to facilitate combustion; diesel engines and natural-gas-fueled spark-ignition engines are also common. The waste heat from these engines could be recovered and use directly (in the case of natural-gas-fired systems) or used in heat exchangers to provide hot water or steam. If only half of the waste heat were used, a powerplant's energy output would double, providing a new revenue stream for the community and enabling the engines to be operated economically. These potential benefits would be weighed against the cost of installing and operating the heat recovery system.

However, cogeneration at an existing rural powerplant could increase oil use if it is substituted for grid-supplied electricity generated with alternate fuels. Therefore, rural communities should focus on technologies that can use locally available biomass fuels such as crop residues, wood, and animal wastes. Gasifiers that convert crop residues or wood to low- or medium-Btu gas can be connected with internal combustion engines, although the engines will need some modification for trouble-free operation over long periods of time. Such gasifiers are commercially available in Europe and are being demonstrated in the United States. Anaerobic digestion of animal wastes from confined livestock operations also could be used to produce biogas (a mixture of 40 percent carbon dioxide and 60 percent methane) to fuel an internal combustion engine. Anaerobic digestion has the advantages of solving a waste disposal problem, while producing not only biogas but also an effluent that can be used directly as a soil conditioner, dried and used as animal bedding, or possibly treated and used as livestock feed. Digesters for use in cattle, hog, dairy, and poultry operations are commercially available in the United States and are being demonstrated at several rural sites. Wastes from rural-based industries, such as whey from cheese plants, also are being used as a feedstock for farm-based digesters.

Cogeneration can have significant economic and fuel savings advantages in rural communities and on farms. The rural cogeneration potential is not so large as that in industrial and urban applications, but the advantages can be very important in allowing significant local economic expansion—from new jobs and from increased revenues due to steam/heat sales—by using local resources without increasing the base demand for energy.

INTERCONNECTION REQUIREMENTS

The economic and other incentives offered to cogeneration under PURPA assume that cogenerators will be interconnected with the electric utility grid. Such interconnections may require special measures to maintain power quality, to control utility system operations, to protect the safety of lineworkers, and to meter cogenerators' power production and consumption properly. OTA found that most of the technical aspects of interconnection are well understood, and the primary issues related to interconnection are the lack of uniform guidelines and the cost of the equipment.

The characteristics of cogenerated electricity that is distributed to the grid must be within certain tolerances so that utilities' and customers' equipment will function properly and not be damaged. Thus, grid-connected cogenerators may need capacitors to keep voltage and current in phase; over/under relays to disconnect the generator automatically if its voltage goes outside a certain range; and a dedicated distribution transformer to isolate voltage flicker problems. Because the power quality impacts of cogenerators are technology- and/or site-specific, not all systems will need all of this equipment. In particular, very small cogenerators (under 20 kW) may have few or no adverse effects on grid power quality and may not require any extra interconnection equipment. Moreover, larger systems probably will already have dedicated transformers, and may only need power factor correcting capacitors if they use induction (as opposed to synchronous) generators.

Proper interconnection is necessary to ensure the safety of utility workers during repairs to transmission and distribution lines. First, cogenerators should locate their disconnect switches in specified areas in order to simplify lineworkers' disconnect procedures. In addition, induction generators (and, very occasionally, synchronous generators) must use voltage and frequency relays and automatic disconnect circuit breakers to protect against self-excitation of the generator. Alternatively, the power factor correcting capacitors can be located where they will be disconnected along with the cogenerator (and thus prevent self-excitation) or where they can be isolated easily by lineworkers.

Large numbers of grid-connected cogenerators that are dispatched by the electric utility may require expensive telemetry equipment and could overload utility system dispatch capabilities. However, these problems can be avoided if utilities treat cogenerators as "negative loads" by subtracting the power produced by the generators from total system demand and then dispatching the central generating capacity to meet the reduced load. Most utilities currently use negative load scheduling with cogenerators (and small power producers), and some studies indicate that it may work well even with large numbers of cogenerators. However, some utilities question whether the system would continue to function properly if a significant percentage of total system capacity were undispatched cogenerators being treated as negative loads. Additional research is needed to determine whether undispatched cogenerators will cause problems for a utility system and, if so, at what degree of system penetration such problems would arise.

Finally, cogenerators' power production and consumption must be metered accurately in order to provide better data on their output characteristics (and thus facilitate utility system planning), and to ensure proper pricing for buyback and backup power. Cogenerators can be metered inexpensively with two standard watt-hour meters—one operating normally to measure consumption and the other running backwards to indicate production. Alternatively, advanced meters can be installed that indicate not only kilowatthours used/produced but also power factor correction and time-of-use. These advanced meters provide better data about cogeneration's contribution to utility system loads, and they facilitate accurate accounting (and thus pricing) of power purchased and sold. However, advanced meters also cost about five times more than two standard watt-hour meters.

Estimates of the cost for interconnection vary widely—from $12/kW for a large cogenerator to $1 ,300/kw for a small system—depending on the generator type, the system size, the amount of equipment already in place, and a particular utility's or State public service commission's requirements for equipment type and quality. In general, interconnection costs will be higher if a dedicated transformer is needed. Economies of scale also are apparent for circuit breakers, transformers, and installation costs. Moreover, some utilities or commissions may require more equipment than described above in order to provide extra protection for their system and the other customers. The quality of the interconnection equipment required also may affect costs substantially. Some utilities allow smaller cogenerators to use lower quality and less expensive industrial-grade equipment, but the size cutoff varies widely among utilities—from 200 to 1,000 kW. In other areas, all cogenerators are required to use the higher quality utility-grade equipment, but with such equipment the cost of interconnection may be prohibitive for small cogenerators. Few guidelines exist for the type and quality of interconnection equipment necessary for cogenerators, but several are under preparation. Once standard guidelines are available, interconnection costs should become more certain.

IMPACTS OF COGENERATION

Cogeneration has the potential for both beneficial and adverse effects on fuel use, utility planning and operations, and the environment. In each case, OTA found that the potential negative impacts could be mitigated substantially if the cogeneration technology is carefully selected and sited, if the cogenerator works closely with the utility throughout the project's planning and implementation, and if the cogeneration system is carefully integrated with existing and planned future energy supplies.

Effects on Fuel Use

All cogenerators will save fuel because they produce electric and thermal energy more efficiently than the separate conversion technologies they will displace (e.g., an electric utility powerplant and an industrial boiler). Whether cogeneration will save oil depends on the fuel used by a cogenerator and the fuels used in the separate systems that are displaced. If both of the separate technologies burn oil and would continue to do so for most of the useful life of the cogenerator that supplants them, then even an oil burning cogenerator will reduce total oil consumption. However, if either or both of the separate conventional technologies use an alternate fuel (e.g., coal, nuclear, hydroelectric, biomass, solar), or would be converted to an alternate fuel during the useful life of a cogenerator, then oil-fired cogeneration would increase total system oil use.

Where oil savings are available through cogeneration, their magnitude will depend on the type of cogenerator and the types of separate conversion technologies that are displaced, as well as on the rates for purchases of cogenerated power under PURPA. For example, an oil-fired steam turbine cogenerator could reduce oil use by 15 percent if it is substituted for an oil-fueled steam electric powerplant and separate low-pressure steam boiler, while a diesel cogenerator that recovers three-quarters of the potentially usable heat could represent a 25 percent savings if it replaces a diesel electric generator and separate oil burning furnace. (Much greater savings are available if an alternate-fueled cogenerator replaces separate oil-fired systems.)

Higher rates for utility purchases of cogenerated power will favor technologies with high E/S ratios, thus increasing the potential to displace utility generating capacity, much of which will be intermediate and peakload plants that burn oil. However, because currently available high E/S cogenerators also are limited to the use of oil (or natural gas), care must be exercised in deploying these technologies if it is important to ensure that oil savings are achieved over the useful life of the cogenerator. In many cases, the market (high prices and uncertain availability), regulatory provisions, tax measures, and the utility's avoided costs will provide such insurance.

Impacts on Utility Planning and Operations

Cogeneration can offer significant economic savings for utilities that need to add new capacity. Where utilities need to displace oil-fired capacity or accommodate demand growth, cogeneration can bean attractive alternative to conventional powerplants. Cogenerators' relatively small unit size and short construction leadtime can provide more flexibility than large baseload plants for utilities in adjusting to unexpected changes in demand, and cogeneration is a more cost-effective form of insurance against such changes than the overbuilding of central station capacity. Cogeneration also has the potential to significantly reduce interest costs during construction (and thus the overall cost of providing electricity).

Relying on cogeneration capacity instead of conventional powerplants should not pose significant operating problems for utilities if the cogenerators are properly connected to the grid. As discussed previously, large numbers of small grid-connected cogenerators should not overburden utility system dispatch capabilities if they are treated as negative loads, but the effects of a substantial penetration of a system are uncertain.

However, expansion of cogeneration could have a substantial adverse economic impact on utilities that have excess capacity and/or a low rate of growth in demand. If large industrial and commercial sites drop out of a utility's load, then the utility's fixed costs must be shared among fewer customers, who would then have higher electric rates. This competition has been observed in other regulated industries (e.g., telecommunications, railroads). The effects of such competition are essentially the same as those of the competition from conservation measures or of the excess capacity that can result from oil displacement.

Where utilities already have excess capacity or are committed to major construction programs that cannot be deferred, the risk of reduced fixed cost coverage can be acute. In the long run, such competition could represent a benefit for most utilities by reducing the need for new capacity and thus relieving financial pressures on utilities and lowering rate levels. But until the construction budget is adjusted, the short-term effects of revenue losses could be severe for some utilities and their remaining customers.

Furthermore, if utilities purchase power from cogenerators based on the utility's full avoided cost, the utility's non-cogenerating customers may not receive any economic benefit from cogeneration. Cogenerators usually will be installed only where their operating costs would be less than the avoided cost rate paid by the utility for their power. If the cogenerator receives the full difference, the ratepayer will receive no direct benefit. This situation is exacerbated if the avoided cost payments are higher than the utility's actual short-run marginal cost (e.g., if the State regulatory commission bases avoided costs on the price of oil and the utility operates with a mix of fuels, or if the commission establishes a high avoided cost as an explicit subsidy to encourage cogeneration). A payment to cogenerators of less than the utility's full avoided cost, with the difference going toward rate reduction, would share any cost benefits of cogeneration with the utility's other ratepayers.

One solution to both the competition posed by cogeneration and the rate reduction issue is for utilities to own cogenerators. ownership could be advantageous to a utility because the cogenerator would be included in the utility's rate base and thus the utility would earn a percentage return on the equipment. Where cogeneration is economically competitive with other types of capacity additions, utilities should be investing in it. However, cogeneration systems that are more than 50 percent utility-owned are not eligible for the economic and regulatory incentives established under PURPA, which often determine economic competitiveness. If full utility ownership were allowed incentives under PURPA, cogeneration's market potential probably would increase, as would the amount of electricity it would supply to the grid (because utilities would be more likely to install high E/S ratio technologies). In addition, utility investment in cogeneration would have the economic advantages related to the small unit size and shorter construction leadtimes discussed previously, and could result in lower electricity rates compared to conventional capacity additions. However, full utility ownership under PURPA raises a number of concerns about possible anti-competitive effects and about the resulting profits to utilities; these are discussed in more detail under "Policy Considerations," below.

Environmental Impacts

The primary environmental concern about cogeneration is the public health effects of changes in air quality. Cogeneration will not automatically offer air quality improvement or degradation compared to the separate conversion technologies it will replace. Cogeneration's greater fuel efficiency may lead to either a decrease or an increase in the total emissions associated with electric and thermal energy production, depending on the types of combustion equipment, their scale, and fuel used. Similarly, cogeneration may improve or degrade air quality by shifting emissions away from a few central powerplants with tall stacks to many dispersed facilities with shorter stacks, depending on the variables listed above as well as on the location of the cogenerators and the separate systems they replace.

Of the available cogeneration technologies, diesel and gas-fired spark-ignition engines have the greatest potential for adverse air quality impacts due to their high–but usually controllable–nitrogen oxide emissions. Diesels also emit potentially toxic particulate, but clear medical evidence of a human health hazard is lacking at this time. Steam and gas turbines should not result in an increase in total emissions unless they use a "dirtier" fuel than the separate conversion technologies they replace (e.g., a shift from distillate oil to high sulfur coal), or where a new turbine cogenerator that primarily produces electricity is installed instead of a new boiler or furnace.

Adverse local air quality impacts are most likely to occur with cogeneration in urban areas, because urban cogenerators usually will be diesels or spark-ignition engines, because urban areas would have a higher total population exposure, and because tall buildings can interfere with pollutant dispersion. Moreover, the small systems that would be used in these applications tend to have high nitrogen oxide and particulate emissions. As a result of these considerations, urban cogenerators must be designed and sited carefully, including choosing an engine model with low emissions, applying technological emission controls, and ensuring that the exhaust stacks are taller than surrounding buildings.

Cogenerators' greater fuel efficiency also can lead to an important environmental benefit in other aspects of a fuel cycle (e.g., exploration, extraction, refining/processing) if a cogenerator uses the same fuel as the conventional energy systems it displaces. However, if a fuel that is difficult to extract, process, and transport (e.g., coal) is substituted for a "cleaner" fuel (such as natural gas), the overall impact may be adverse rather than beneficial.

Finally, cogeneration might affect water quality (from blowdown from boilers and wet cooling systems, and from runoff from coal piles and scrubber sludge and ash disposal), waste disposal (sludge and ash), noise, and materials (from cooling tower drift). All of these will be more likely to pose a problem in urban areas, and all are either controllable and/or are more likely to be a nuisance than a health hazard.

Socioeconomic Impacts

General trends for impacts on economic and social parameters such as capital investment, operating and maintenance (O&M) costs (excluding fuel costs), and labor requirements cannot be identified at this time due to the large uncertainties in future deployment patterns. These impacts will depend heavily on the size and type of cogenerators used, the size and type of separate conversion technologies that would be displaced, the regions in which cogeneration would be installed (construction costs and labor requirements generally are lower in the South), and cogenerators' operating characteristics. For example, in comparing cogeneration capital costs with those for conventional baseload and peakload capacity, OTA found that the cost of installing 100,000 MW of electric generating capacity under cogeneration scenarios varied from about 25 percent more to approximately 95 percent less than the cost of installing an equivalent amount of capacity under conventional central station scenarios, depending on the capacity mix and location for each scenario.

For purposes of comparison, OTA analyzed the mean values for capital and O&M costs, and for construction and O&M labor requirements, for 50,000, 100,000, and 150,000 MW of electricity-generating capacity with and without cogeneration. In this comparison, OTA found that mean capital costs for cogeneration tended to be around 20 to 40 percent lower than the mean costs for an equivalent amount of conventional utility capacity. Because cogenerators have a shorter construction leadtime than conventional powerplants, savings on interest charges during construction would increase this capital cost difference. The O&M cost differences were calculated for two different cogeneration capacity factors–45 and 90 percent. With a capacity factor of 90 percent, mean cogeneration O&M costs were higher (25 to 70 percent) than mean utility O&M costs, while cogenerators operating at a 45 percent capacity factor had mean O&M costs ranging from approximately 20 percent higher to roughly 35 percent lower than mean utility costs.

Construction and O&M labor requirements both tended to be higher for the cogeneration scenarios than for the central station capacity scenarios. Up to 50 percent more construction labor might be required for cogeneration than for utility capacity. The O&M labor requirements varied much more widely due to the lack of data and the pronounced economies of scale for cogeneration O&M labor.

In general, these results confirm reports in the literature that cogeneration could save investment capital while increasing direct employment in electricity supply. However, the actual economic and employment effects might be much different if the mix of technologies installed were different from those examined by OTA.

POLICY CONSIDERATIONS

The primary Federal policy initiatives that affect the deployment of cogeneration capacity include provisions of title II of PURPA, the Powerplant and Industrial Fuel Use Act of 1978 (FUA), the Clean Air Act, and the tax laws, as well as Government support for research and development. In general, the combined focus of these initiatives is to encourage grid-connected cogeneration that will use energy economically and utility resources efficiently. Although the long-term effects of these policies on cogeneration implementation are still uncertain (due to delays in State implementation and to ongoing changes in Federal priorities), a number of unresolved issues have been identified for possible further congressional action. These include the use of oil in cogeneration, the economic incentives for cogeneration, utility ownership of cogeneration capacity, requirements for interconnection with the grid, and the effects of cogenerators on local air quality.

Oil Savings

Despite their inherent energy efficiency, not all cogenerators will save oil. The purchase power rate provisions of PURPA, FUA prohibitions on oil use in powerplants and industrial boilers, and the energy tax credits discourage cogeneration applications that would increase oil use, but they may not be effective in all cases. For example, cogenerators with less than about 10-MW generating capacity or that sell less than half their annual electric output, are automatically exempt from FUA prohibitions. Similarly, an oil-fired cogenerator may not be entitled to rates for utility purchases of cogenerated power under PURPA that are as high as those paid to systems burning alternate fuels, but the installation could be economic without those payments (e.g., if retail electricity rates are very high). Moreover, an existing industrial or commercial oil burning energy system could be retrofitted for cogeneration and still qualify for the energy tax credit as long as onsite energy use is reduced.

In many cases, the uncertain price and long-term availability of oil, coupled with regulatory and economic disincentives to its use, will be sufficient to discourage oil-fired cogeneration. However, where oil-fired cogenerators still would be economic but would not provide lifetime oil savings, additional policy initiatives might be considered if net oil savings is the primary goal. These include amending FUA to prohibit the use of oil in all cogenerators regardless of size or electricity sales unless a net lifetime oil savings can be demonstrated; amending PURPA to deny qualifying facility status (and thus economic and regulatory incentives) to oil burning cogenerators unless net oil savings are shown; and amending the investment and energy tax credits and other tax code provisions to deny tax deductions, credits, or other measures for cogeneration projects unless net oil savings are demonstrated. However, these measures may only provide oil savings of less than 100,000 barrels per day in 1990. Moreover, net oil savings are difficult to prove, and these regulations could be expensive and time-consuming for both potential cogenerators and implementing agencies, and could discourage even those cogeneration systems that would save oil.

If net oil savings is the primary goal, there are several policy alternatives to additional layers of fuel use regulations. First, oil consumption could be taxed (e.g., with an oil import fee). Such a tax would encourage conservation in all oil markets and provide additional Federal revenues. Alternatively, restrictions in FUA and the tax laws on the use of natural gas in cogenerators might be eliminated. Natural gas for cogeneration is likely to be competitive with oil, and gas-fired cogenerators usually will be technically and economically attractive in the same situations as oil burning systems. Moreover, gas-fired cogeneration could provide a bridge to the development of gasification systems using alternative fuels. Thus, removing regulatory and tax restrictions on the use of natural gas in cogenerators would complement market disincentives to oil use, by presenting an economically attractive alternative in those situations where oil might otherwise be favored.

On the other hand, if gasification systems do not become commercial as soon as their developers project, or if the cost of producing low- or medium-Btu gas remains significantly higher than the cost of natural gas, then this strategy could lock cogenerators into natural gas use for 10 to 20 years. Moreover, if natural gas-fired cogeneration were given incorrect incentives, and made more attractive than market conditions would justify, this could discourage the use of non-premium fuels (e.g., coal, biomass, wastes) and add to the demand for natural gas. If supplies are limited, the cogenerators' demand could increase supply pressures for established gas users.

Economic Incentives for Cogeneration

Cogeneration's market potential (the amount of cogeneration capacity that may be installed and the amount of electricity that it will produce) is extremely sensitive to economic considerations. These include the rates for utility purchases of cogenerated power, tax credits and leasing provisions, and other policy measures that either reduce the capital cost or offset the operating cost of cogeneration systems. At present, however, the continued availability of existing policy initiatives is in doubt.

A recent court decision vacated the Federal Energy Regulatory Commission (FERC) regulations implementing PURPA that called for utility purchases of cogenerated power at rates equal to 100 percent of the incremental cost saved by the utility by not generating the power itself or purchasing it from the grid (termed the utility's "avoided cost"). The court held that FERC had not adequately justified rates based on the full avoided cost when a lower rate would still compensate most cogenerators adequately while sharing the economic benefits of cogeneration with the utility's ratepayers. In order for the ratepayers to share in any cost benefits of cogeneration, less than full avoided costs would have to be paid to the cogenerator, with the difference going to rate reductions, or the utility would have to own the cogenerator. The full avoided cost rates remain in effect pending final resolution in the case (including appeals and revision of the regulations, if necessary), but uncertainty about the long-term purchase rates is substantially discouraging cogeneration except in those cases where State legislatures or regulatory commissions have instituted full avoided cost rates on their own initiative.

A second source of uncertainty is the 1982 expiration date for the special energy tax credit. The availability of this credit often can make or break the economic feasibility of cogeneration projects (and other alternate energy systems). Due to the currently high interest rates and the promise of improved technologies now under development or demonstration, many potential cogenerators would prefer to wait several years before making their investment. The continued availability of the energy tax credit (perhaps through 1990) could help to ensure that those investments would be made, while an earlier expiration date might encourage the installation of less efficient existing technologies.

Finally, if the Government wanted to maximize cogeneration's market potential, then policies that substantially reduce capital costs might be implemented. With the current high interest rates, debt financing—the primary mode of financing for potential cogenerators—is unattractive or unavailable. Therefore, subsidies that lower interest rates and extend loan terms may be more attractive than tax credits.

Utility Ownership

Electric utility ownership could substantially increase cogeneration's market potential. Power production is electric utilities' primary business and they would thus not be subject to many of the qualms of industrial or commercial concerns that are unaccustomed to producing electric power or that place higher priorities on investments in process equipment. Some utilities may require a lower return on their investment than other types of investors, and a cogeneration project that may only be marginally economic for an industrial or commercial firm could be attractive to a utility. Moreover, utility ownership could allay concerns about competition from cogenerators.

Although there are no legal restrictions on utility ownership of cogenerating capacity, such ownership is at a competitive disadvantage because cogenerators in which electric utilities or utility holding companies own more than a 50-percent equity interest do not qualify for the economic and regulatory incentives under PURPA, and because public utility property is not eligible for the energy tax credit. Removing these disincentives would place utilities in an equal (at least) position with other investors with regard to cogeneration, and could substantially increase the production of cogenerated electricity.

However, full utility ownership under PURPA raises concerns about the possible effects of such ownership on competition and on utility obligations to minimize electricity generation costs. Utilities could favor their own (or their subsidiaries') projects in contracting for cogeneration capacity. They also might favor a few major established suppliers of cogeneration equipment, leading to the possibility of adverse effects on small business and the development of innovative technologies. Moreover, if a utility is paying its subsidiary for cogenerated electricity based on the utility's avoided cost of generation or purchases from the grid, then the utility has few incentives to reduce its marginal costs, because to do so would be to reduce the subsidiaries' rate of return and profitability. while these concerns about utility ownership under PURPA are real, they can be allayed through carefully drafted legislation or regulations, or through careful State review of utility ownership schemes. If these cautionary measures are taken, the benefits of utility ownership probably would outweigh the potential for anti-competitive and economic costs.

interconnection Requirements

The requirements for interconnecting and integrating cogenerators with utility transmission and distribution systems have become both technical and institutional issues. There are technical issues because of the wide variability among States and utilities on the type and quality of equipment that is necessary to regulate system power quality, protect the safety of utility employees, maintain control over system operations, meter cogenerators' electricity production and consumption properly, and prevent damage to utilities' and other customers' equipment. Few guidelines exist for interconnection needs, but the equipment required can add enough to a project's costs to make cogeneration economically infeasible. As a result, a high priority should be placed on the preparation of guidelines for utilities and State commissions to follow in setting interconnection requirements.

Second, utilities' legal obligation to interconnect is unclear. FERC regulations implementing PURPA established a general obligation to interconnect in order to carry out the statutory mandate that utilities must purchase power from and sell it to cogenerators. However, PURPA also amended the Federal Power Act to provide for full evidentiary hearings on interconnections upon the request of a utility or a qualifying cogenerator. The U.S. Court of Appeals recently ruled that the Federal Power Act procedure was the valid one. Therefore, if a utility is not willing to interconnect, the cogenerator must go through the costly and time-consuming process of such a hearing. Furthermore, most of the showings required of the petitioner in such a hearing would be extremely difficult and expensive for a potential cogenerator to make. This issue probably can only be resolved through a congressional amendment to PURPA that specifies utilities' obligation to interconnect with cogenerators (and small power producers) and leaves resolution of technical and cost issues to State utility commissions.

Air Quality Considerations

Proponents of cogeneration have argued that air pollution control regulations unnecessarily restrict the deployment of cogenerators. They suggest that cogenerators be given special treatment that accounts for their increased fuel efficiency and their displacement of emissions from centrally generated electricity. Proposed changes include emission standards that are tied to the amount of energy output rather than the fuel input, or separate and more lenient emissions limitations for cogenerators; and less strict new source review procedures for cogenerators under prevention of significant deterioration and nonattainment area provisions of the Clean Air Act (e.g., by allowing an automatic offset for reductions in powerplant and boiler emissions).

Although these changes would remove some disincentives to cogeneration, OTA found that in many situations there is no public health or environmental justification for automatically granting cogenerators relief from air quality requirements. A potentially more productive alternative would be to favor situations where cogenerators can demonstrate that they will have a positive net impact on air quality. In those cases, relief from regulatory requirements could be granted on a case-by-case basis. Review of individual cases will be especially important in urban areas where small internal combustion engine cogenerators that are not regulated under the Clean Air Act could have significant adverse impacts on air quality.

Research and Development

The most promising cogeneration applications are those that can use fuels other than oil and that can produce significant amounts of electricity. Of the currently available technologies (that are widely applicable), only steam turbines can accommodate solid fuels. But steam turbines have a low E/S ratio. Higher E/S ratio technologies are available, but can only use oil or gas. Therefore, research and development efforts should concentrate on demonstrating high E/S cogenerators that can burn solid fuels cleanly, and on advanced combustion systems such as fluidized beds that can be used in conjunction with a cogenerator. Because many potential cogenerators will not be able to burn solid fuels directly (due to site, environmental, or resource availability limitations), special attention also should be paid to the development and demonstration of gasifiers that would convert solid fuels to synthetic gas onsite, or for transport to the cogeneration site. Gasifiers would allow available cogeneration technologies to be installed now and use natural gas (currently relatively abundant) until synthetic gas becomes available.

Research also should be directed at removing the remaining technical uncertainties in interconnection, developing lower cost pollution control technologies for small generators, and improving coal transportation and handling in urban areas.

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