Chapter 4

Characterization of the Technologies for Cogeneration

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INTRODUCTION

Cogeneration systems recapture otherwise wasted thermal energy, usually from a heat engine producing electricity (such as a steam turbine, gas turbine, or diesel engine), and use it for space conditioning, industrial processes, or as an energy source for another system component (31). This "cascading" of energy use is what distinguishes cogeneration systems from conventional separate electric and thermal energy systems (e.g., a powerplant and an industrial boiler), or from simple heat recovery strategies. The automobile engine is a familiar cogeneration system that provides mechanical shaft power to move the car, produces electricity with the alternator to run the electrical system, and recirculates the engine's otherwise wasted heat to provide comfort conditioning in the winter.

This chapter characterizes the technical features of cogeneration systems, including an overview of the general fuel use and energy production considerations common to all cogenerators, a description of the operating characteristics and costs of both commercially available and promising future cogeneration technologies, and a discussion of ancillary systems such as those for interconnecting cogenerators with the utility grid, for improving cogenerators' fuel flexibility, and for storing the electric or thermal energy. A more detailed characterization of cogeneration technologies may be found in volume II of this report.

The principal technical advantage of cogeneration systems is their ability to improve the efficiency of fuel use in the production of electric and thermal energy. Less fuel is required to produce a given amount of electric and thermal energy in a single cogeneration unit than is needed to generate the same quantities of both types of energy in separate, conventional technologies (e.g., turbine-generator sets and steam boilers). This is because waste heat from the turbine-generator set, which uses a substantial quantity of the fuel used to fire the turbine, becomes useful thermal energy in a cogeneration system (e.g., process steam) rather than being "wasted. " To be sure, this usually requires some reduction in the amount of electricity produced compared to a stand-alone turbine generator, but this "sacrifice" usually is acceptable to gain the 10- to 30-percent increase in overall fuel efficiency offered by cogeneration (31). To see more clearly how this gain is achieved, box A provides a detailed look at the thermodynamics of cogeneration.

The relative efficiency of cogenerators and conventional powerplants is shown in figure 16. In a conventional steam plant (which generally uses a Rankine cycle), energy must be added to the feedwater in the boiler in sufficient amounts to raise it up to point A in figure 16 (steam for power generation). However, due to inherent inefficiencies in the Rankine cycle turbine, the condensing turbines that drive the generators can only utilize the amount of energy between points A and C in the figure (steam at the boiling point) to generate electricity. Thus, the large amount of energy from the boiler feedwater level to point C is lost as the steam is condensed by cooling water, carrying off the heat, and rejecting it to the environment.

In the cogeneration plant in figure 16, the energy from A to B (steam) is used to generate electricity, the energy from B to D (water at boiling point) is used as process steam, and only the energy from D down to the feedwater level is rejected to the environment. Thus, the cogenerator allows use of some of the energy that the conventional powerplant otherwise would waste. Level B is determined by the temperature required for the process steam.

Different types of cogenerators have differing fuel use characteristics and produce different proportions of electricity and steam. The electricity-to-steam (E/S) ratio refers to the relative proportions of electric and thermal energy produced by a cogenerator. The E/S ratio is measured in kilowatthours per million Btu (kWh/MMBtu) of steam (or useful thermal energy), and varies among the efficiencies but higher second law efficiencies and save more fuel. This distinction is recognized in the topping-cycle cogeneration efficiency standards set by the Federal Energy Regulatory Commission under the Public Utility Regulatory Policies Act, which gives a 2-to-1 weighting to electricity generation compared to thermal energy production (see ch. 5).

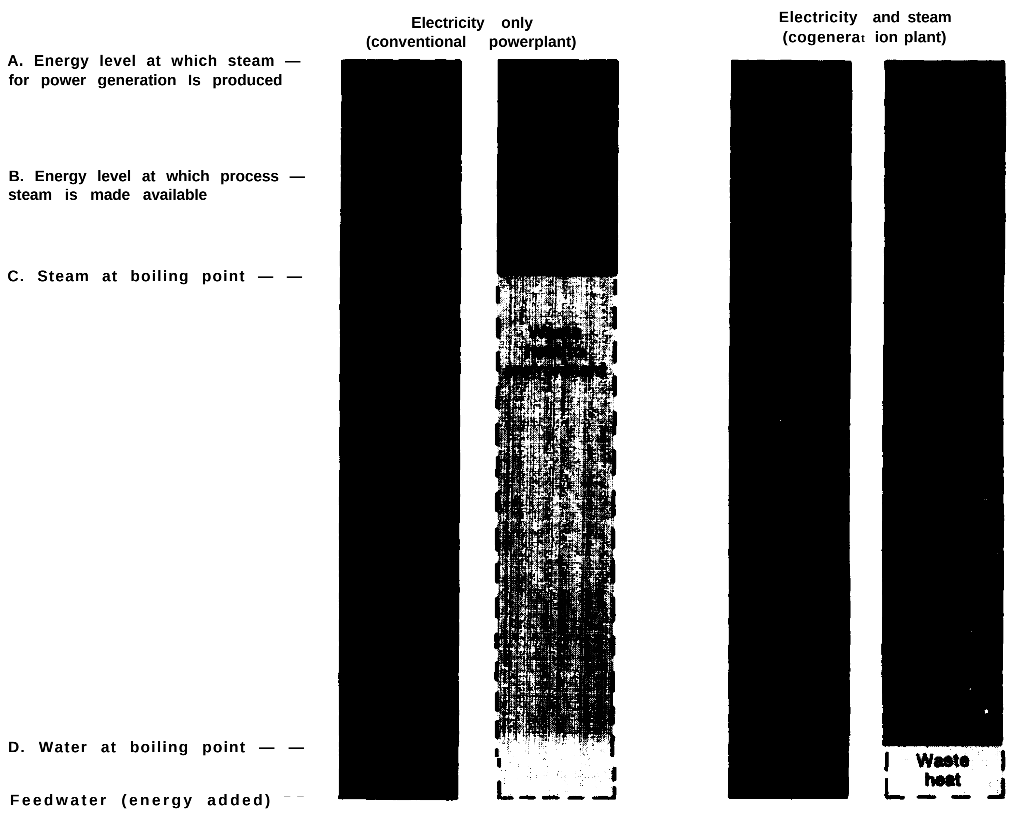
Table 22.—Performance Characteristics of [illegible]

	[illegible]	[illegible]	[illegible]	[illegible]
Central station electricity generation	[illegible]	[illegible]	[illegible]	[illegible]
Process steam production (e.g., in an industrial boiler, about 550° F)	[illegible]	[illegible]	[illegible]	[illegible]
Cogeneration systems:				
Steam turbine	[illegible]	[illegible]	[illegible]	[illegible]
Gas turbine	[illegible]	[illegible]	[illegible]	[illegible]
Combined cycle (gas/steam turbine)	[illegible]	[illegible]	[illegible]	[illegible]
Diesel	[illegible]	[illegible]	[illegible]	[illegible]

[a]Fuel saved per unit of [illegible]

SOURCE: Marc H. Ross and Robert H. Williams, [illegible] (New York: McGraw-Hill Book Co., 1981); [illegible] Calif.: Annual Reviews, Inc., 1979).

Figure 16.—Comparlson of Energy Utilization In a Cogeneratlon System and a Conventlonal Powerplant



SOURCE: Dow Chemical Co., et al., *Energy industrial Canter Study (Washington,* D. C.: National Science Foundation, June 1975).

different types of cogeneration technologies (see table 23).

The total heat rate refers to the total amount of fuel (measured in Btu) required to produce 1 kwh of electricity, with no credit given for the use of "waste heat." The net heat rate (also measured in Btu/kWh) credits the thermal output and denotes the fuel required to produce electricity, beyond what would be needed to produce a given quantity of thermal energy in a separate facility (e.g., a boiler). In a central powerplant, where no heat is recovered, an average total heat rate is 10,500 Btu/kWh (60). Cogenerators have a net heat rate of about 4,300 to 7,500 Btu/kWh depending on the characteristics of the thermal energy produced. Thus, depending on the cogenerator type and how completely the thermal output is utilized, electricity can be produced by a cogenerator with about one-half to three-fourths the fuel used in central power generation (45,60). Fuel use efficiency for a cogenerator gives credit to the thermal output; hence it is the ratio of electric output plus heat recovered in Btu to fuel input in Btu.

Table 21 presents a numerical example of heat rates and fuel efficiency-based on modern steam turbines—that compares: 1) an ideal engine exhausting to a low temperature, 2) a real engine exhausting to a low temperature (typical of a utility powerplant), 3) a real engine exhausting at a higher temperature with the heat wasted (something that is best to avoid), and 4) a real engine exhausting at a higher temperature with the heat utilized (as with a cogenerator). it is noted that, in the example in table 21, the fuel use efficiency varies from 35 percent for the utility powerplant to 75 percent for the cogenerator.

Table 23.—Summary of Cogeneration Technologies

Technology	Unit size	Fuels used (present/possible In future)	Average annual availability (percent)	Full-load electric efficiency (percent)	Part-load (at 50°/0 load) electrlc efficiency (percent)	Total heat rate (Btu/kWh)	Net heat rate (Btu/kWh)	Electriclty-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 liquida.	90-95	14-28	12-25	12,200-24,000	4,500-6,000	30-75
B. Open-cycle gas turbine topping	100 kW-100 MW	Natural gas, distillate, treated resldual/coal- or biomass-derived gases and liquids.	*90-95*	24-35	19-29	9,750-14,200	5,5004,500	140-225
G. Glosed-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. Comblned gas turbine/steam turbine topping	4 MW-1OO MW	Natural gas, dlstlllate, resldual/coal- or blomass-dertved 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	6,300-10,300	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,OOO-34,1OO	NA	NA
Organic	2 kW-2 MW	Waste heat.	80-90	10-20	Comparable to full load	17,OOO-34,1OO	NA	NA
G. Fuel cell topping	40 kW-25 MW	Hydrogen, distlllate/coal.	90-92	37-45	3745	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 tur-bines and diesels,	35-41	34-40	8,300-9,750	5,500-6,500	340-500

Table 23.—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 applicability
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 cogeneration 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	430-600	5.0-5.5	3.0-5.1	2-3	15-25	Commercially available; advanced systems by 1965.	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	350-600	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	600-1,500	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 2000 600"F range.
G. Fuel cell topping	520-840[c]	0.26-33	1.0-3.0	1-2	10-15	Still in development and experimental stage. phosphoric acid expected by 1965, molten carbonate by 1990.	Modular nature, low emissions, excellent part-load characteristics allow for utility load following 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 Could be used in residential, commercial, and industrial applications. Industrial use depends on development of large Stirling engines.

"NA" means not applicable.
a,960 dollars.
bDepends on system size and heat source.
cCost estimates assume successful development and commercial-scale production, and are not guaranteed.

SOURCE: Office of Technology Assessment from material in ch. 4.

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COGENERATION TECHNOLOGIES

Most cogeneration systems can be described either as "topping" systems or "bottoming" systems, depending on whether the electrical or thermal energy is produced first. * In a topping system—the most common cogeneration mode—electricity is produced first. The thermal energy that is exhausted is captured and used for such purposes as industrial processes, space heating and cooling, water heating, or even producing more electricity *(18).* Topping systems would be used in residential/commercial and most industrial cogeneration applications.

In a bottoming system, 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 working fluid, generally through a waste heat recovery boiler. The fluid is vaporized and used to drive a turbine (Rankine cycle) to produce electrical energy (18). Bottoming cycles are used mostly in industries where high-temperature waste heat is available, and thus are limited to a few industrial processes. Further, they tend to have a higher capital cost than topping systems.

The cogeneration systems described below are: 1) steam turbine topping, 2) open-cycle gas turbine topping, 3) closed-cycle gas turbine topping, 4) combined-cycle (gas/steam turbine) topping systems, 5) diesel topping, 6) Rankine cycle (steam and organic) bottoming, 7) fuel cell topping, and 8) Stirling engine topping. A fuel cell, being a chemical device, is the only technology that is not a heat engine although it is considered a topping cycle cogeneration system.

These technologies include small systems (75 kW to 10 megawatts (MW)) that might be used to supply electricity and heat for a single building or a building complex such as a shopping center; intermediate size cogenerators of several to tens of megawatts for industrial applications; and large centralized systems that could supply electricity to the utility grid and distribute steam to nearby industries or to district heating systems. Potential cogeneration applications in industry, commercial buildings, and rural areas are discussed in detail in chapter 5.

The steam turbine, open-cycle gas turbine, combined-cycle, diesel, and steam Rankine bottoming cogenerators represent commercially available technologies although advanced models with improved efficiency, lower cost, and greater fuel flexibility are under development. The closed-cycle gas turbine is available in other countries and could be introduced in the United States at any time. Organic Rankine bottoming cycles, fuel cells, and Stirling engines are not commercially available in the United States, but are sufficiently well developed to be considered "near term" cogeneration technologies (available within 5 to 15 years). As with all predictions of commercial readiness for developing technologies, however, care must be exercised and actual progress observed closely–as noted from the long and difficult history of Stirling engines.

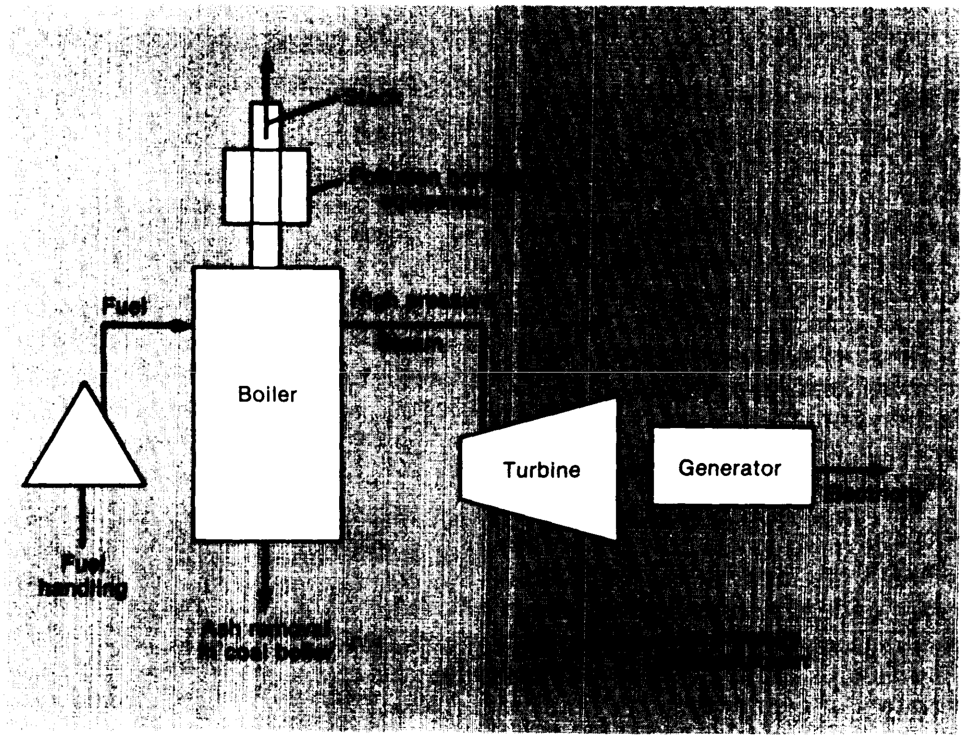
The general operating and performance characteristics and costs of these cogeneration technologies are summarized below and in table 23. Detailed technology descriptions may be found in volume II.

Steam Turbines

Historically, steam turbines have been the primary cogeneration technology, providing mechanical and electric power and steam for a variety of industrial processes. A schematic of a steam turbine in a cogeneration application is shown in figure 17. The system consists of a boiler and a back pressure turbine. Mechanical energy is produced as the high-pressure steam from the boiler drives the turbine. The mechanical energy is then converted to electricity by turning a generator rotor attached to the turbine. The steam, which leaves the turbine at a reduced pressure and temperature (300° to 700° F), can be used in many industrial applications (see ch. 5).

*Operating and efficiency standards for topping and bottoming cycle cogenerators promulgated by the Federal Energy Regulatory Commission under the Public Utility Regulatory Policies Act are discussed in ch. 3.

Figure 17.—Steam Turbine Topping System in a Cogeneration Configuration



SOURCE: Thermo Electron Corp., *Analysis of Cogeneration Systems Applicable to the State of New Jersey* (Waltham, Mass.: Thermo Electron Corp., TE5486-103-8O, December 1979).

The technical and operating characteristics of steam turbines present both advantages and disadvantages relative to other types of cogenerators. Steam turbine engines are available in a wide range of sizes, from 500 kW to well over 550 MW, although 100 MW is probably a reasonable ceiling for most industrial applications. Currently, steam turbine boilers can accommodate a wider variety of fuels than other available cogeneration systems (including oil, natural or synthesis gas, coal, wood, solid waste, and industrial byproducts), although individual boilers can only be designed to accommodate two fuel sources at one time (i.e., dual-fueled boilers can be built to use oil or gas, coal or oil, gas or coal). Steam turbine cogenerators also have extremely high unit reliability, availability, and service lifetime. With respect to reliability, steam turbines have a maximum forced outage rate of around 5 percent. Their unit availability also is quite high (90 to 95 percent) because scheduled maintenance requirements are relatively low. The expected service lifetime of steam turbine cogenerators is from 25 to 35 years.

A final technical advantage of steam turbine cogenerators is their high overall fuel efficiency, which ranges from 65 to 85 percent, and generally is not affected by turbine inlet temperatures or by part-load operation (when less than the maximum possible amount of electricity is being produced). However, steam turbines' efficiency of electricity generation increases with increasing inlet temperature and pressure ratio, and with size up to about 30 MW.

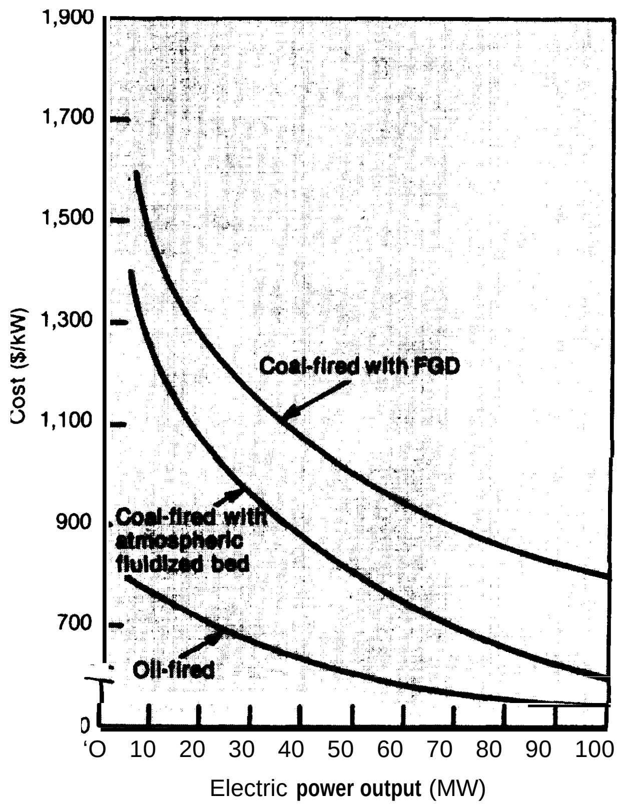
On the other hand, steam turbine cogenerators have relatively long installation leadtimes–12 to 18 months for smaller systems and up to 3 years for larger units—from the time equipment is ordered until operation begins. This is due primarily to the time required to certify and install high--pressure boilers. For coal burning systems, the installation of fuel handling equipment can add significantly to the leadtime.

Steam turbines also have relatively low ratios of electric-to-thermal power production (E/S ratio) because they have a relatively low upper temperature limit. It is this temperature which, in combination with the desired steam temperature, determines the amount of electricity that can be generated. Of the 85 percent useful energy obtainable in steam turbine cogeneration systems, typically 14 percent would be electric power and 71 percent process heat. However, the E/S ratio will vary according to the amount of high-pressure steam that is directed from the boiler for process heat. Thus, an increase in process steam temperature corresponds to a decline in electric power production and an increase in heat production. Overall fuel utilization (power plus heat) remains relatively constant at a variety of process temperatures. All that changes is the proportion of total fuel use devoted to electric generation and process heat. Research and development (R&D) efforts are underway on advanced steam turbine models that would operate at higher temperatures and pressures and thus would be more efficient generators of electricity.

The costs of steam turbine cogenerators vary depending on the size of the system, the kind of fuel it uses, and its combustion source (e.g., boiler, fluidized bed combustor, gasifier). Figure 18 presents total installed costs for steam turbine systems. Coal-fired steam turbines with flue gas desulfurization (FGD) (for environmental control purposes) range in cost from $800 to $1 ,600/kW installed capacity. These systems constitute the most expensive steam turbine option, with costs generally $200/kW greater than turbines with fluidized bed boilers, which would not need FGD in order to meet air quality standards. Oil-fired boilers for steam turbines constitute the least expensive option, with installed cost estimates ranging from $550 to $800/kW—about $200 to $600/ kW below the expected costs for atmospheric fluidized bed (AFB) boiler turbines. * Economies of scale are evident for steam turbine cogenerators larger than about 10 MW.

*It should be noted that estimates for steam turbine system costs vary greatly according to the data source. The degree of accuracy of the different estimates is difficult to verify without actual construction of the various systems.

Figure 18.—Estimated Steam Turbine Cogenerator System Instaiied Costs With Different Heat Sources



SOURCE: Off Ice of Technology Assessment.

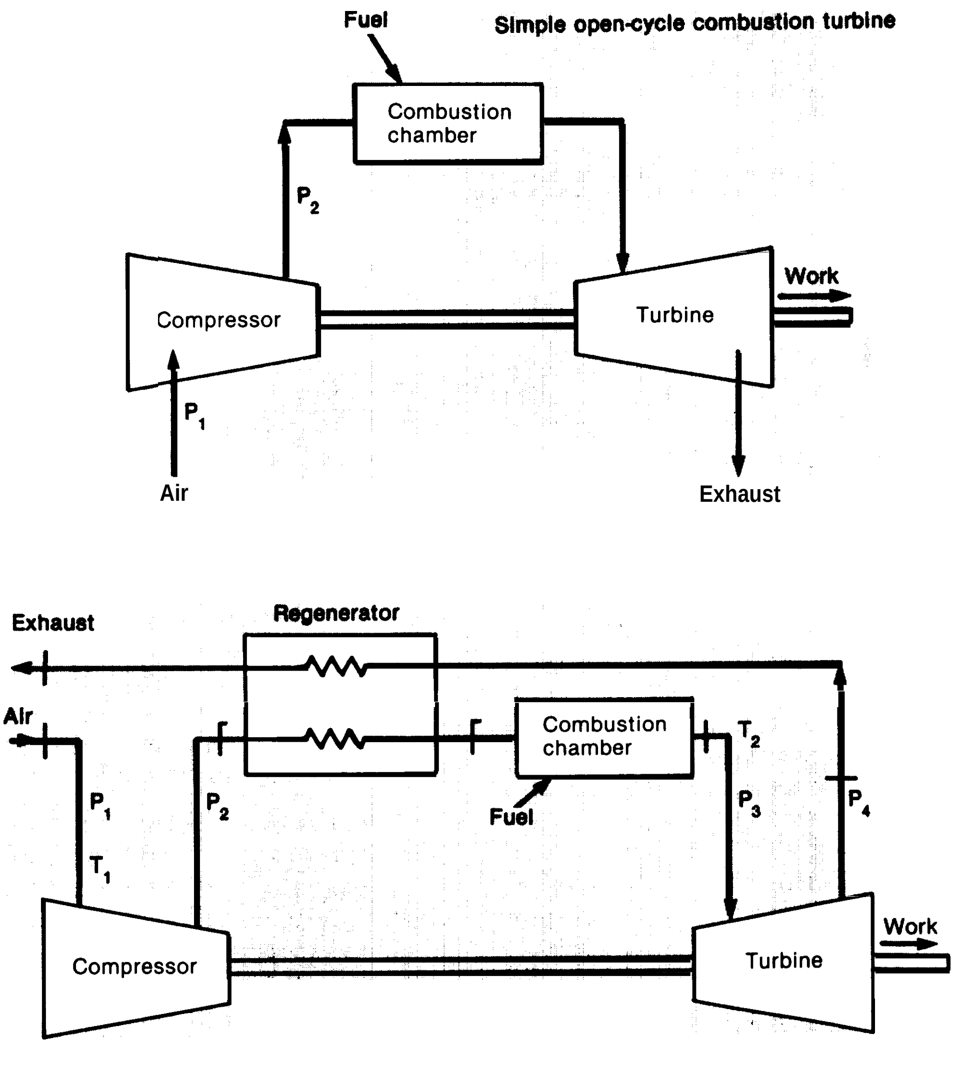
The cost for advanced steam turbine prime movers also differs according to the size of the unit. For smaller units (less than 5 MW), advanced steam turbine installed costs may be $150 to $200/kW greater than the cost of current steam turbines. For 1O-MW units, the incremental cost of advanced steam turbines is approximately $5o to $100/kW greater, while for 100-MW units, the prices are approximately the same as currently available systems (55).

Estimates for variable operation and maintenance (O&M) costs for steam turbine topping cycles (excluding fuel cost) vary from 3.0 to 8.8 milis/kWh depending on the source of the estimate. For a residual oil-fired steam turbine, in general, a 4.0 mills/kWh O&M cost appears to be a reasonable estimate. Estimates of O&M costs for large steam turbines are 6.0 mills/kWh with FGD, 4.2 mills/kWh without FGD, 5.2 mills/kWh with AFBs, and 8.8 mills/kW/h with pressurized fluidized beds. Fixed annual O&M costs range from $1.6 to $1 1.5/kWh of installed capacity.

Open= Cycle Combustion Turbines

Most combustion turbines are open-cycle systems in which air is drawn in from the atmosphere and exhaust gases are released to the atmosphere (i. e., the air or other working fluid is not recirculated). Figure 19 provides system schematics for both simple and regenerative open-cycle gas turbines. Figure 20 presents the configu ration a simple open-cycle combustion turbine with a heat recovery unit would take in a cogeneration application. For both simple and regenerative turbine types, air is compressed, then heated in the combustion chamber to the required turbine inlet temperature, and expanded through the turbine. The primary difference between the simple and regenerative open-cycle

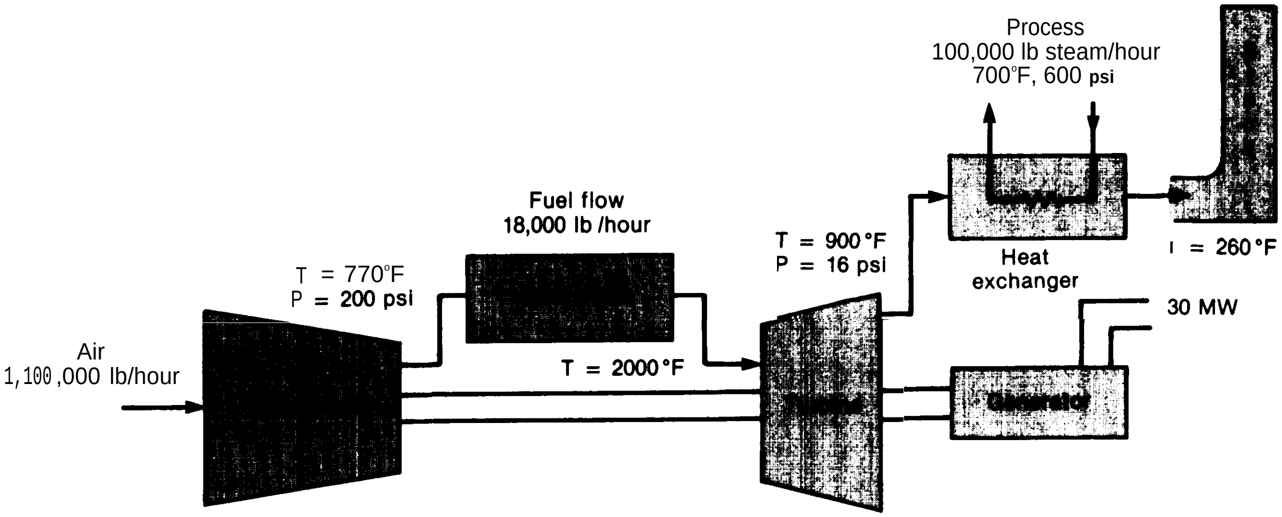
Figure 19.—Combustion Turbine



Regenerative open-cycle combustion turbine

SOURCE: Arthur D. Little, Inc., *Distributed Energy Systems: A Review of Related Technologies* (Washington, D. C.: U.S Department of Energy, DOE/PE 03871-01, November 1979).

Figure 20.-Schematic of a Simple Open-Cycie Combustion Turbine in a Cogeneration Application



SOURCE: United Technologies Corp., *Cogeneration Technology Alternative Study (CTAS) — Volumes I-VI* (Cleveland, Ohio: National Aeronautics and Space Admin. istration, Lewis Research Center, and Washington, D. C.: U.S. Department of Energy, DOE/NASA/00W80/1 -6, January 1980).

turbines is that in the latter, the low-pressure hot exhaust gases are used to preheat the high-pressure compressor discharge air in a regenerator. The waste heat boiler system recovers heat from the hot gas produced by the turbine and generates high- and low-pressure thermal energy to be utilized in industrial processes or for space conditioning.

Simple open-cycle combustion turbine systems with waste heat boilers currently are available in size ranges from 100 kw to 100 MW. Regenerative turbines are available in sizes from about 16 MW to 70 MW. Most combustion turbines burn natural gas or diesel oil, and can be converted from one to the other in about 1 day. Because turbine blades in open-cycle systems are exposed to the products of combustion, these products must be free of impurities (e.g., sodium, potassium, calcium, vanadium, iron, sulfur, and particulates) that can cause corrosion, and the residual solids must be small enough to avoid erosion of the turbine blades. As a result, currently available open-cycle combustion turbines cannot use solid fuels (coal, biomass) directly (i.e., without first liquefying or gasifying them), and cannot burn residual oil or liquid or gaseous fuels from coal or biomass without an auxiliary fuel cleaning system (see discussion of fuel flexibility in the next section).

Open-cycle combustion turbine cogenerators have a shorter installation leadtime than steam turbines—around 9 to 14 months for gas turbines up to 7 MW, and as long as 2 years for larger units. The reliability of combustion turbines and their average annual availability should be comparable to that of steam turbines, although units that burn liquid fuels or that are operated only intermittently will require about three times more maintenance—and thus will have a lower percent availability—than those that use natural gas. On the other hand, the expected useful service life of open-cycle combustion turbines tends to be lower than that of steam turbines–typically 15 to 20 years—and poor maintenance, the use of liquid fuels, or intermittent operation can reduce the service life substantially.

Open-cycle combustion turbine cogenerators tend to have slightly lower overall fuel efficiency than steam turbines, but the most efficient combustion turbines can have a higher overall efficiency than the least efficient steam turbines. on the other hand, open-cycle combustion turbines have much higher E/S ratios than steam turbines (typically 140 to 225 kWh/MMBtu for combustion turbines, as compared to 30 to 75 kWh/. MMBtu for steam turbines), and a higher electric generating efficiency at both full- and partload operation (see table 23). Unlike steam turbines, however, combustion turbine cogenerators' electric efficiency is reduced significantly by part-load operation. Moreover, the efficiency of open-cycle combustion turbines varies with the addition of a regenerator, because regenerative cycles produce additional electricity at the expense of recoverable thermal energy and overall efficiency. Therefore, for cogeneration applications, **overall fuel efficiency** will be higher with simple open-cycle combustion turbines, but **electric generating efficiency** (both full- and part-load) will be higher with regenerative open cycles. As with steam turbines, the efficiency of open-cycle combustion turbines tends to increase with size up to about 30 MW, and remains relatively constant in larger systems.

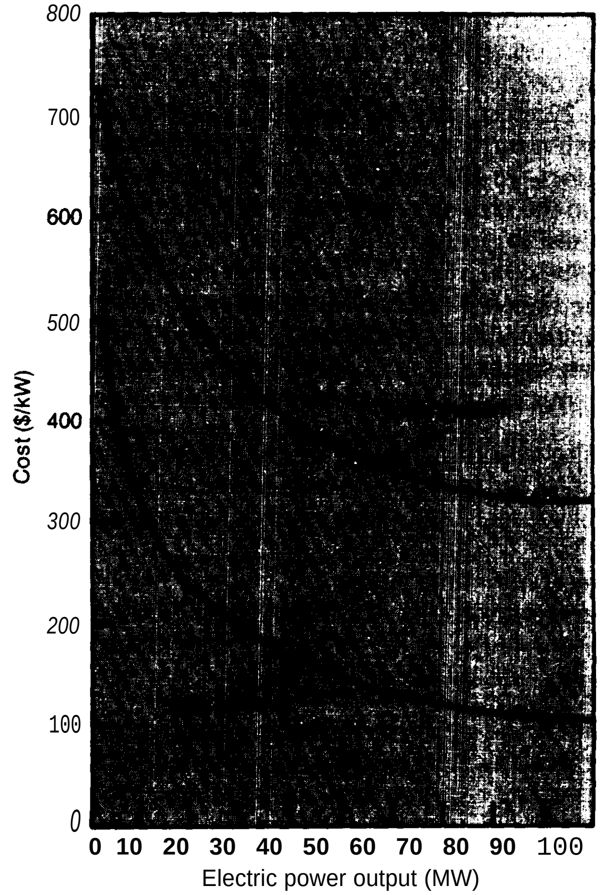
R&D on advanced combustion turbine cogenerators focuses on systems that operate at higher turbine inlet temperatures in order to improve operating efficiency, and on systems that can accommodate a wider range of fuels. The primary R&D considerations are:

- improved cooling of turbine blades,
- changes in turbine blade materials (possibly to temperature resistant ceramic coatings) to withstand higher inlet temperatures, and
- changes in turbine blade materials to improve their anticorrosive properties in order to allow the use of alternate fuels.

The **installed costs** for open-cycle combustion turbine cogenerators are shown in figure 21, broken down by the cost of the prime mover versus that for the total system. As can be seen in this figure, total system installed costs range from $320/kW installed capacity for very large (100-MW) gas turbine cogenerators, to over $700/kW for very small units. Economies of scale are apparent in systems larger than about 20 to 30 MW. In general, regenerative-cycle combustion turbines cost about $15 to $100/kW more than simple cycles.

Estimated **variable O&M costs** for combustion turbines are 2.5 mills/kWh. Operating expenses for advanced combustion turbines probably will be slightly higher—perhaps 2.8 to 3.0 mills/kWh depending on the fuel used. Annual **fixed O&M costs** for combustion turbine topping cycles are

Figure 21.—Combustion Turbine Cogenerator Cost Estimates for the Prime Mover and Total Installed System



SOURCE: Office of Technology Assessment.

low and tend to be about $0.29/kW for simple cycles and $0.34/kW for regenerative cycles.

Closed-Cycle Combustion Turbines

In closed-cycle combustion turbine systems, the working fluid (usually either helium or air) circulates through a closed circuit, and is heated to the required inlet temperature by a heat exchanger. This arrangement ensures that both the working fluid and the turbine machinery are isolated from both the combustion chamber (heat source) and the products of combustion, and thus erosion and corrosion problems in the turbine are avoided. This external combustion design thus permits greater fuel flexibility than is possible in currently available open-cycle turbines. Closed-cycle systems can burn coal, industrial or municipal wastes, biomass, or liquid or gaseous fuels derived from them. Nuclear or solar energy may be used for these systems in the future. Figure 22 presents schematics of closed-cycle combustion turbine systems with and without regenerators. In the regenerative closed cycle, heat from the working fluid that is leaving the turbine is used to preheat the working fluid that is leaving the compressor. Closed-cycle combustion turbine cogenerators have not been commercially available in the United States in the past, but have been successful in Europe and Japan and could be introduced here at any time.

The actual configuration of closed-cycle combustion turbine systems will vary according to the heat source. Likely heat sources for these systems include coal-fired AFB combustors and liquid-fueled high-temperature furnaces. The installation leadtime for a 25-MW system with an AFB is estimated to be 4.5 to 5 years, with an expected service life of about 20 years.

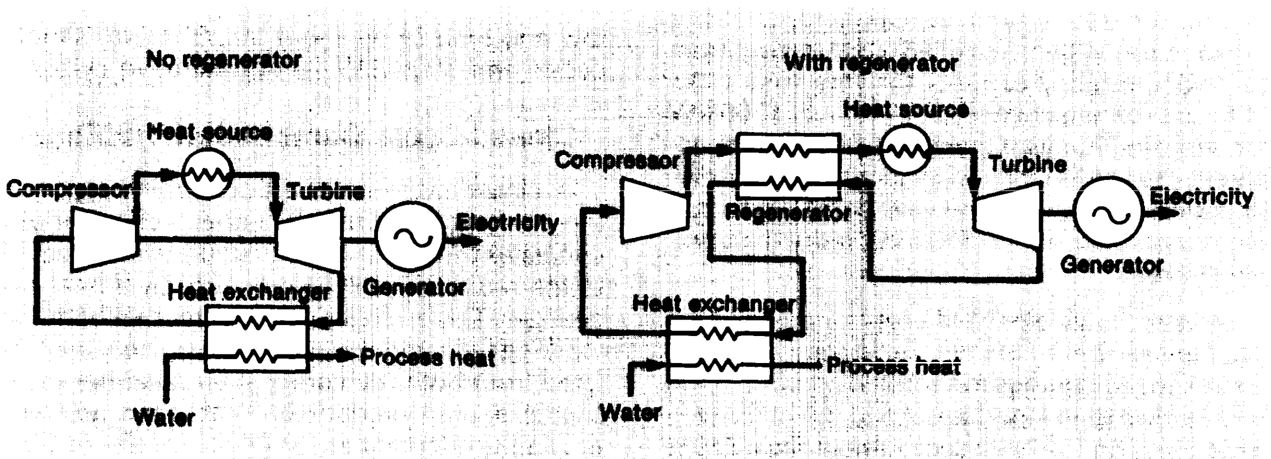
In closed-cycle systems, any gas can serve as the working fluid. Air has the advantage of reducing sealing requirements and mechanical complications. Heavy molecular weight gases (such as argon) reduce the size of the turbomachinery but increase that of the heat transfer components, while light molecular weight gases (such as helium) require more extensive turbomachinery and minimize the size of heat transfer equipment. This flexibility' contrasts sharply with open-cycle combustion turbine systems, which are limited to the hot combustion gases as the working fluid.

Closed-cycle combustion turbines are thus physically smaller than open cycles, but require more piping and heat exchangers. In addition, the small physical size of the turbomachinery limits the power of closed-cycle turbines. Consequently, systems with capacities below 500 kW are not considered economically attractive. Electric capacity in currently operating closed-cycle gas turbine systems (in Europe and japan) ranges from 2 to 50 MW.

The average annual reliability and availability of closed-cycle combustion turbines is expected to be at least as good as that for open cycles once sufficient operating experience has been accumulated with the former. However, because the closed-cycle configuration reduces wear and tear on the turbine blades, closed-cycle systems may require less maintenance (and thus have a higher availability) than open cycles.

The overall fuel efficiency of closed-cycle combustion turbine cogenerators also is expected to be comparable to that of open cycles, as is the

Figure 22.—Closed-Cycle Gas Turbines With and Without Regeneration

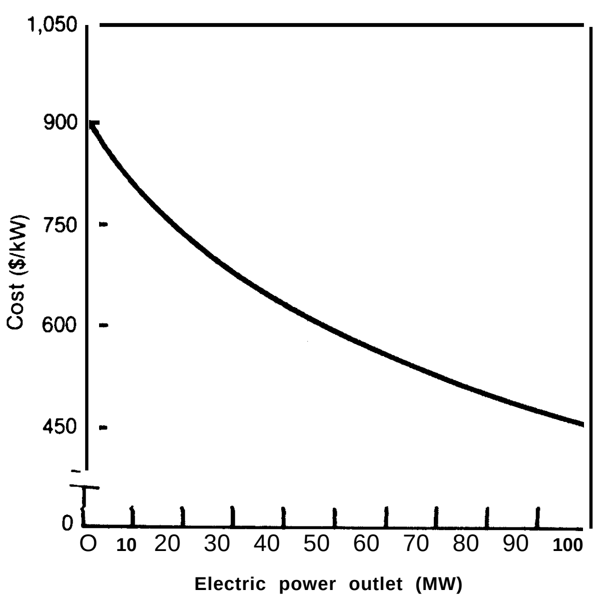


SOURCE: United Technologies Corp., *Cogeneration Technology Alternative Study (CTAS)— Volumes /-V/* (Cleveland, Ohio: National Aeronautics and Space Administration, Lewis Research Center, and Washington, D. C.: U.S. Department of Energy, DOE/NASA/OOW-8011 -6, January 1960).

E/S ratio (see table 23). Similarly, use of a regenerator with a closed cycle will increase electricity output but reduce the temperature of the recovered heat. Unlike open-cycle systems, however, part-load operation of a closed-cycle gas turbine cogenerator does not reduce electric generating efficiency, and may actually increase it when a regenerator is used. In this case a closed-cycle system is much like a steam turbine in that the working fluid and the combustion gases are separate. This allows more control, which in turn makes possible more constant part-load operation. The effect of part-load operation on overall fuel efficiency will depend on the part-load efficiency of the heat source (e.g., fluidized bed, hot gas furnace). Finally, overall efficiency will tend to increase slightly with system size up to about 25 MVV.

Detailed installed cost information for closed-cycle combustion turbine cogenerators is limited due to the lack of experience with these systems in the United States. Figure 23 presents estimates for various size systems showing a range for total installed costs (exclusive of heat source) from $450 to $900/kW. Economies of scale are significant for larger systems (approximately 25 MW and above), primarily as a result of the low incremental cost of fuel handling equipment with increasing capacity.

Figure 23.—Closed-Cycle Gas Turbine Cogenerator Installed Cost (exclusive of heat source)



SOURCE: Off Ice of Technology Assessment

The lack of U.S. operating experience with closed-cycle combustion turbine cogenerators precludes any definitive estimate of O&M costs. A representative estimate for fixed plus variable O&M costs in the literature surveyed is 5 percent of installed cost per year of operation.

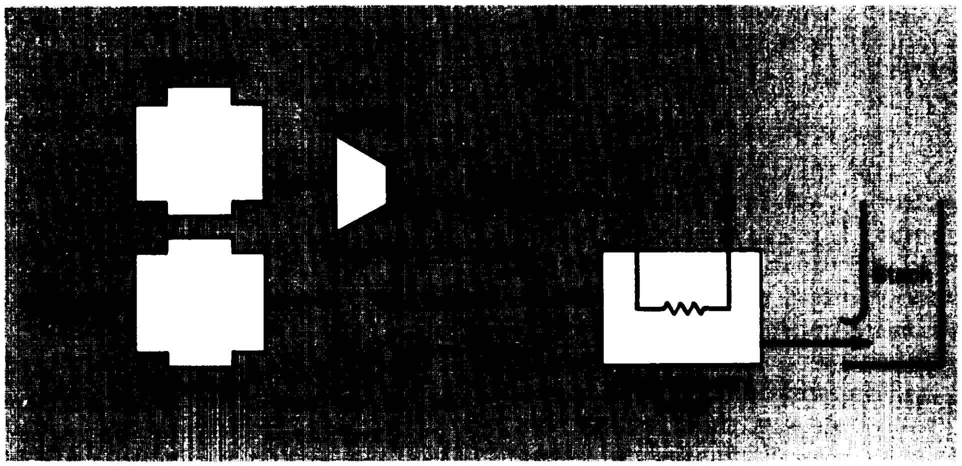
Combined Cycles

The term “combined cycle” is applied to systems with two interconnected cycles operating at different temperatures. The higher temperature (topping) cycle rejects heat that is recovered and used in the lower temperature (bottoming) cycle to produce additional power and improve overall conversion efficiency. Currently available combined-cycle cogenerators use a combustion turbine topping cycle in combination with a steam-bottoming cycle.

A schematic of such a combined-cycle plant is shown in figure 24. The major components of the system are the combustion turbine generator, the heat recovery boiler, and the steam turbine. Note that this system is like the combustion turbine cogeneration systems discussed previously except that steam from the heat recovery boiler is used first to generate electricity and then exhausted for process heat and ultimately waste heat. In most combined-cycle systems, extra fuel is burned in the heat recovery boiler to supplement the heat in the combustion turbine exhaust, The high percentage of oxygen (17 percent) in the combustion turbine’s exhaust guarantees efficient supplemental combustion under the heat recovery boiler. Supplemental firing generally improves thermal efficiency at part-load operation, but makes combined-cycle plant operation control more complex and thus increases maintenance costs.

Combined-cycle cogenerators typically are available in sizes ranging from 22 to about 400 MW. However, smaller units have been installed, and at least one company currently is developing small, prepackaged combined-cycle units in the 4-to 11 -MW size range (50). Installation time from the date the equipment is ordered ranges

Figure 24.—Schematic of a Combined-Cycle Cogenerator



SOURCE: United Technologies Corp., *Cogeneratlon Technology Alternat/ve Study (CTAS)– Volume I-Vl* (Cleveland, Ohio: National Aeronautics and Space Administration, Lewis Research Center, and Washington, D. C.: US. Department of Energy, DOE/NASA/0030-'60H -6, January 1980).

from 2 to 3 years. It is generally possible to have a two-stage installation in which the combustion turbine system can be operable within 12 to 18 months. The steam turbine can then be installed while the combustion turbines are in operation.

Combined-cycle systems require less floor space than separate combustion or steam turbines producing comparable amounts of electric power. Advanced combined-cycle systems (which will consist of advanced combustion turbines and current technology steam turbines) will be even smaller. Reduced space requirements should increase the potential cogeneration applications for combined-cycle systems.

Fuels employed by available combined-cycle cogenerators are the same as those used by commercial combustion turbines—natural gas, light distillate oil, and other fuels that are free from contaminants. Heavy fuels, such as residual oil, heavy distillates, and coal-derived fuels that are contaminated with trace metals can be used but must be cleaned first. Advanced combined-cycle systems will be able to incorporate fluidized bed combustors that can burn coal (or almost any other fuel). Systems utilizing indirect firing and heat exchangers (i.e., closed cycles) also will be able to run on a wider variety of fuels, because the combustion turbine blades will be isolated from the corrosive influence of fuel combustion.

The maintenance requirements for a combined-cycle system are similar to those for the separate turbines, and average annual availability is lower than for either technology alone (77 to 85 percent). Reliability is around 80 to 85 percent. Economic service life is between 15 and 25 years. However, as with open-cycle combustion turbines, poor maintenance, lower quality fuels, and intermittent operation will decrease the availability, reliability, and service life.

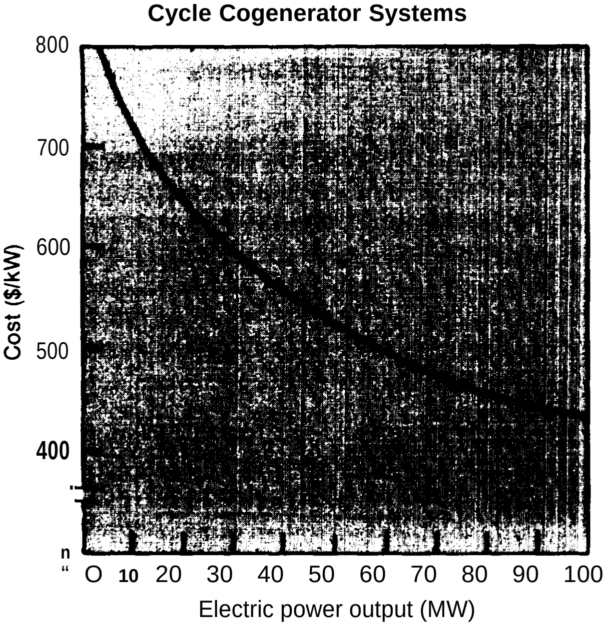
The electric generating efficiency of combined-cycle cogenerators is greater than for simple combustion turbine systems because of the additional electricity generated by the steam turbine. Current combined-cycle systems achieve electric generating efficiencies of between 34 and 40 percent, with 37 percent being typical. This increased efficiency, however, is achieved at the expense of total fuel use (additional fuel is used for supplemental heating of the heat recovery boiler). While available combustion turbines equipped with waste heat boilers typically have a fuel use efficiency of approximately 80 percent, overall fuel efficiency for combined-cycle systems usually is below 60 percent. The electric conversion efficiency of combined cycles increases with capacity up to around 80 MW and remains constant above that size.

As with open-cycle combustion turbines, part-load operation reduces the efficiency of combined cycles. As the gas turbine's generating efficiency drops, more waste heat is supplied to the steam turbine and its percentage of electric load increases. However, the overall efficiency declines because of the increasing amount of waste heat from part-load operation that cannot be recovered.

Typical E/S ratios for combined cycles are 175 to 320 kWh/MMBtu—significantly higher than those for steam turbine topping cycles, and comparable to or slightly higher than open-cycle combustion turbines. However, as mentioned above, as E/S ratio in a combined-cycle system increases the overall fuel efficiency decreases.

Figure 25 presents estimates of total system installed costs for combined cycles. These costs range from approximately $800/kW for a 4-MW unit down to approximately $430/kW for 100-MW units, Combustion turbines represent a larger percentage of the prime mover installed costs than do the steam turbines in these systems.

Figure 25.—Total Installed Costs for Combined-Cycle Cogenerator Systems



SOURCE: Office of Technology Assessment.

Maintenance costs for the combined-cycle system are directly related to the type of fuel used. The lowest maintenance costs are associated with natural gas use, while using residual oil in the combustion turbine will result in the highest maintenance costs, primarily because of the necessity to clean the fuel. Variable O&M cost estimates for combined-cycle systems range from 3.0 to 5.1 mills/kWh while annual fixed O&M costs are from $5.0 to $5.5/kW installed capacity.

Diesels

The diesel engine is a reciprocating internal combustion engine and is a fully developed and mature technology. Cogeneration systems using diesel engines are topping systems and are classified according to whether the diesel engine operates at high, medium, or low speed. Table 24 summarizes the engine speeds for each type of diesel, its capacity range, and its usual applications. All three types have been used in electric power generation—medium- and low-speed diesels by electric utilities for intermediate and peak-load use, and high-speed diesels in the "total energy systems" of the past.

A typical diesel engine topping cogenerator is shown in figure 26. The major system components include an engine, generator, heat recovery unit, fuel handling equipment, and environmental controls. The engine is cooled with water and the heated water used for process steam, heat, or hot water applications. Exhaust gases can be used in a similar manner.

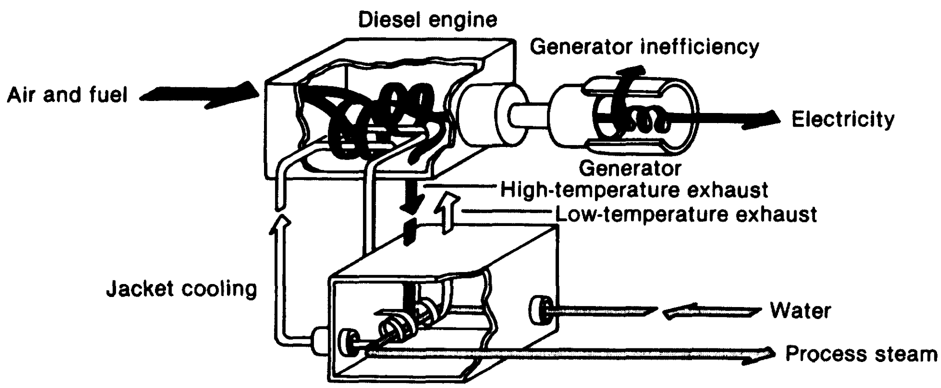
Diesels usually burn natural gas, distillate oil, or treated residual oil, and often have dual fuel

Table 24.-Diesel Engine Characteristics

Type	RPM	Capacity (MW)	Uses
High speed	1,200-3,600	0.075-1.5	Smaller vehicles
Medium speed. .	500-1,200	0.5-10	Marine, rail
Low speed	120-160	2-30	Marine propulsion and industrial use

SOURCES: Office of Technology Assessment from Peter G. Bos and James H Williams, "Cogeneration's Future in the Chemical Process Industries (CPI)," *Chemical Engineering,* Feb. 26, 1979, pp. 104-110; "Electric Power Generation," *McGraw-Hill Yearbook of Science and Technology* (New York: McGraw-Hill Book Co., 1980); Joel Fagenbaum, "Cogeneration: An Energy Saver," *IEEE Spectrum,* August 1980, pp 30-34; and Alan J. Streb, "Cogeneration—What's Ahead?" *Energy Engineering,* April/May 1980, pp. 11.23.

Figure 26.—Diesel Engine Cogenerator



SOURCE: Resource Planning Associates, *Cogeneration: Technical Concepts, Trends, Prospects* (Washington, D. C.: U.S. Department of Energy, DOE-FFU-1703, September 1978).

capability. Two-stroke low-speed diesels also can burn untreated low grade residual oil (58). Research is underway on the use of coal-based fuels in large (low-speed) diesels, including processed solid or liquid coal-derived fuels, or direct coal firing with either a coal/oil or coal/water slurry medium or a dry powdered coal. Slurry-fired diesels may become operational in 5 to 6 years and commercially available in 8 to 10 years. However, additional equipment may be required to control the increased particulate and sulfur dioxide emissions resulting from burning coal or coal-derived fuels. Whether coal burning diesels will be economically competitive is yet unknown.

R&D on diesels also is directed toward increasing the temperature of the cooling water so that steam can be generated, and toward higher supercharge capability and higher charge air cooling. Such advances could result in a 50-percent increase in power output per cylinder (23). Advanced diesels will be ready for wide-scale cogeneration application between 1985 or 1990. “Adiabatic” (or very low heat loss) diesels, which use ceramic parts, also are under development. The principal advantage of the adiabatic diesel would be that all the waste heat would be in the exhaust stream and would be available at high temperature (as with combustion turbines). This technology could significantly improve the versatility of the diesel as well as lead to greater overall fuel use efficiency (61), but is not expected to be commercially available until after 1990.

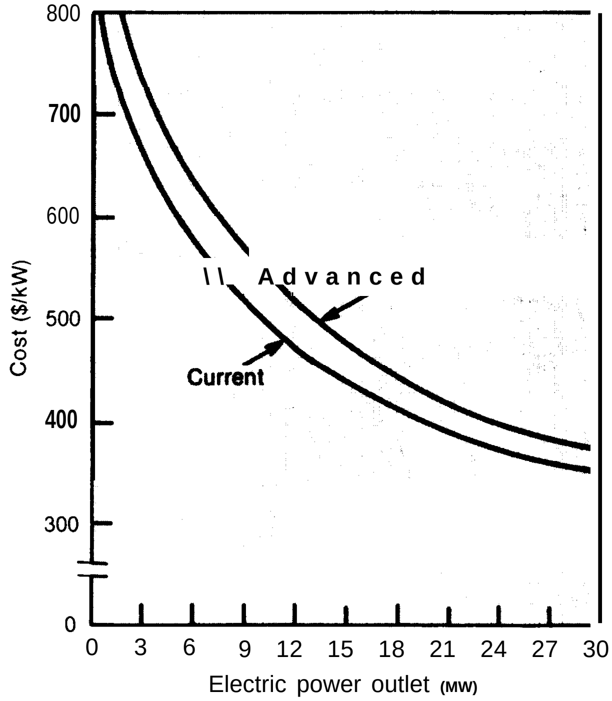
Installation leadtimes for presently available diesel cogenerators range from 9 months for smaller high-speed systems to 2.5 years for larger low-speed units. Maintenance is performed on typical low- and medium-speed diesels every 1,500 hours, and more frequently on high-speed diesels. Average annual availability ranges from 80 to 90 percent. Expected service lifetimes vary from 15 to 25 years depending on unit size, fuel burned, and quality of maintenance.

E/S ratios for diesels are high–from 350 to 700 kWh/MMBtu. Low-speed diesels typically are designed for peak efficiency at 75 percent of full load. Part-load performance for current and advanced technology high-speed diesels is excellent. Medium-speed diesels, whose rated capacities overlap high-speed diesels at the small scale and low-speed diesels at the large scale (see table 24) follow the same trends.

Total installed costs for current and advanced diesel prime movers are given in figure 27. Costs range from $350 to $800/kW for current units, with large advanced systems being slightly higher and smaller ones significantly higher.

Estimates for O&M costs for current and advanced diesels vary significantly depending on

Figure 27.— Diesel Cogenerator Total Installed Costs for Current and 'Advanced Prime Movers



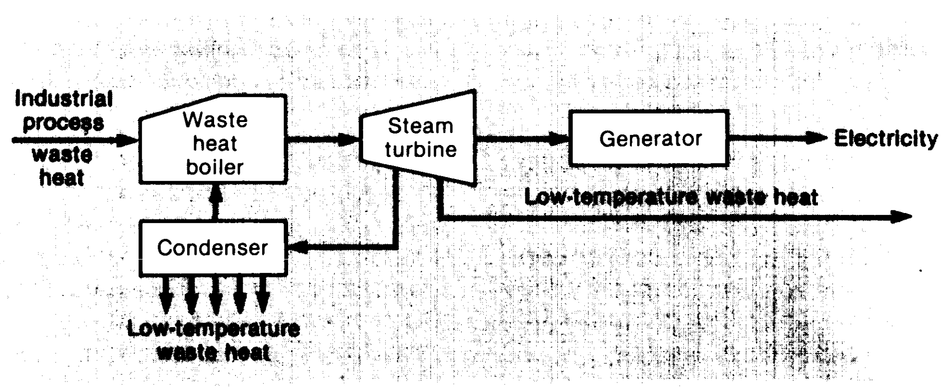
SOURCE: Office of Technology Assessment.

the fuel, the unit's size, and the level of emission control. Fixed O&M costs vary from $6.0 to $8.0/kW annually. Estimates for variable O&M costs range from 1.5 mills/kWh for large low-speed units to 16 mills/kWh for small high-speed units, with 5.0 to 10.0 mills/kWh being a common range.

Rankine Cycle Bottoming

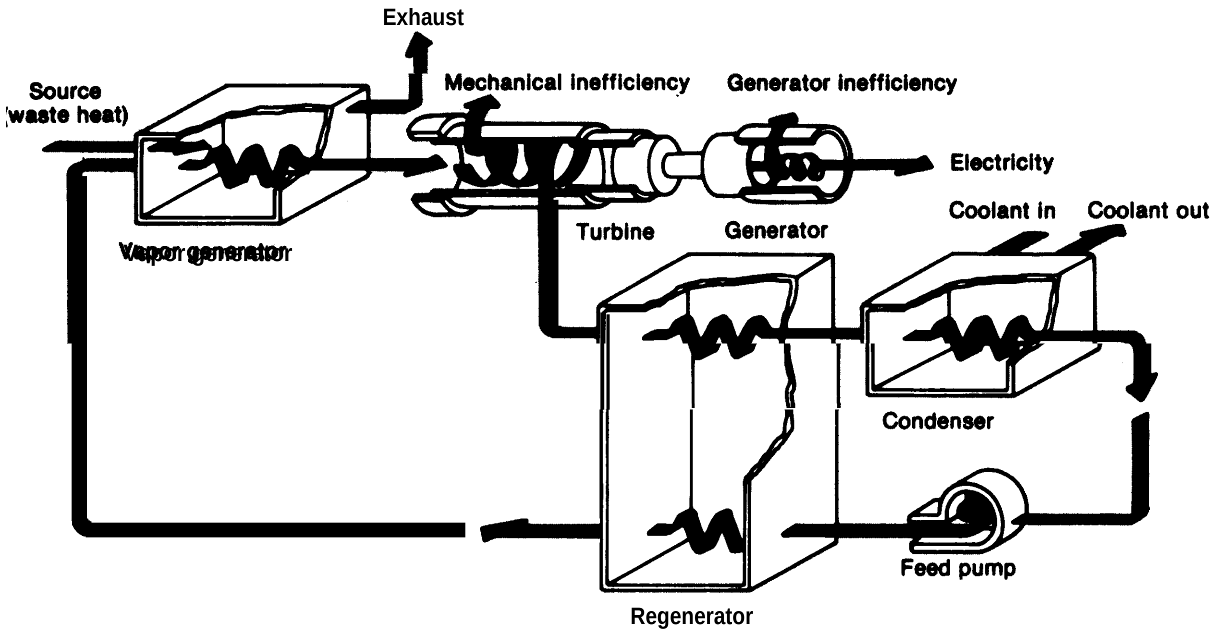
All bottoming cogeneration systems are based on the conventional Rankine cycle (which is the same cycle used in steam turbine topping systems), and are classified according to whether they use steam or organic working fluids. The steam cycle (see fig. 28) uses steam produced in a heat recovery boiler to drive a steam turbine that generates electricity and high- and low-temperature waste heat. This, of course, is just the low-temperature end of the combined-cycle systems discussed before. The high-temperature heat is condensed and either used in process applications or fed back into the boiler through a closed loop. Low-temperature waste heat is lost to the surrounding environment. An organic Rankine cycle (see fig. 29) converts heat energy into mechanical energy by alternately evaporating an organic working fluid (such as toluene) at high pressure and using this vapor to produce shaft power by expanding it through a turbine. The vapor is then recondensed for either process use or reinfection into the heat recovery boiler. Organic working fluids are used when only lower temperature heat sources (200° to 600° F) are available because these fluids vaporize at very low temperatures.

Figure 28.—Steam Rankine Bottoming Cycle



SOURCE: Thermo Electron Corp., *Venture Analysis* Case *Study—Steam Rankine Recovery Cycle Producing Electric Power From Waste Heat* (Waltham, Mass.: Thermo Electron Crop,, TE4231-1 17-78, December 1978).

Figure 29.-Organic Rankine Bottoming Cycle



SOURCE: Reeource Planning Aesociates, *Cogeneration: Technical Concepts Trends, Prospects* (Waehlngton, D. C.: U.S. Department of Energy, DOE-FFU-1703, September 1978).

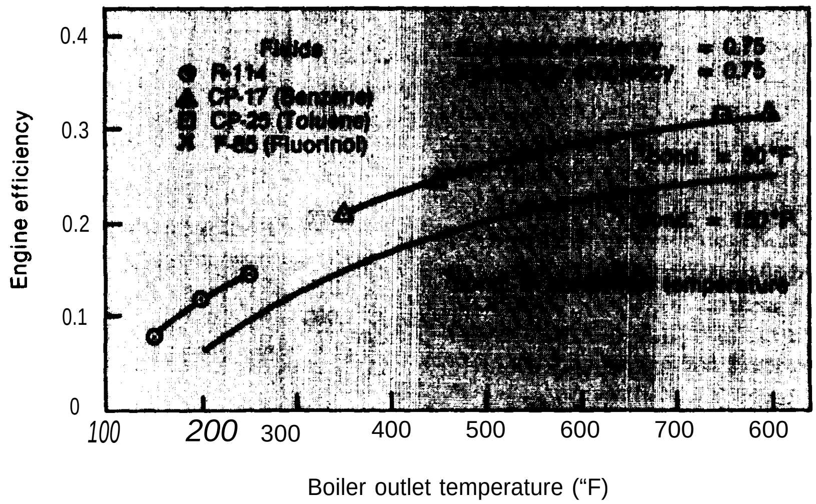
Rankine cycle engines have several characteristics that make them particularly appealing to dispersed electricity generating systems. They are one of the few engines that can effectively utilize heat at temperatures in the 200° to 600° F range. This allows the engines to use a variety of heat sources including solar energy, industrial waste heat streams, geothermal energy, and hot engine exhausts. Rankine engines also can be designed for use over a wide range of capacity levels, from as low as 2 kW for onsite solar applications up to 10 MW for waste heat applications.

The installation time required for organic and steam bottoming cycles generally depends on the size of the plant. For steam Rankine engines, installation times will be similar to those for comparably sized steam turbine topping cycles. Very small organic Rankine units (less than 50 kW), particularly those in commercial applications, will require minimal installation time (4 to 8 months) (2), while larger units are expected to take 1 to 2 years.

Maintenance requirements and reliability for the steam Rankine bottoming cycle also should be comparable to those of steam turbine topping systems (i.e., average annual availability of about 90 percent). Organic Rankine bottoming cycles are a relatively new technology, and information on maintenance schedules and system reliability is not readily available for these systems, but developers of this technology expect availability to be from 80 to 90 percent. Expected service lifetime for both types of bottoming cycles is around 20 years.

Figure 30 shows organic Rankine cycle efficiency as a function of boiler outlet temperature. Note that operation for inlet temperatures below 150° F (about 75°C) is possible. Depending on these parameters, cycle efficiency will range from 5 to 30 percent, with 10 to 20 percent being representative of actual operating conditions. However, because these organic Rankine cycle systems are bottoming systems that operate on the waste heat these efficiencies are not significant

Figure 30.—Organic Rankine Bottoming Cycle Efficiency—Variation With Peak Cycle Temperature

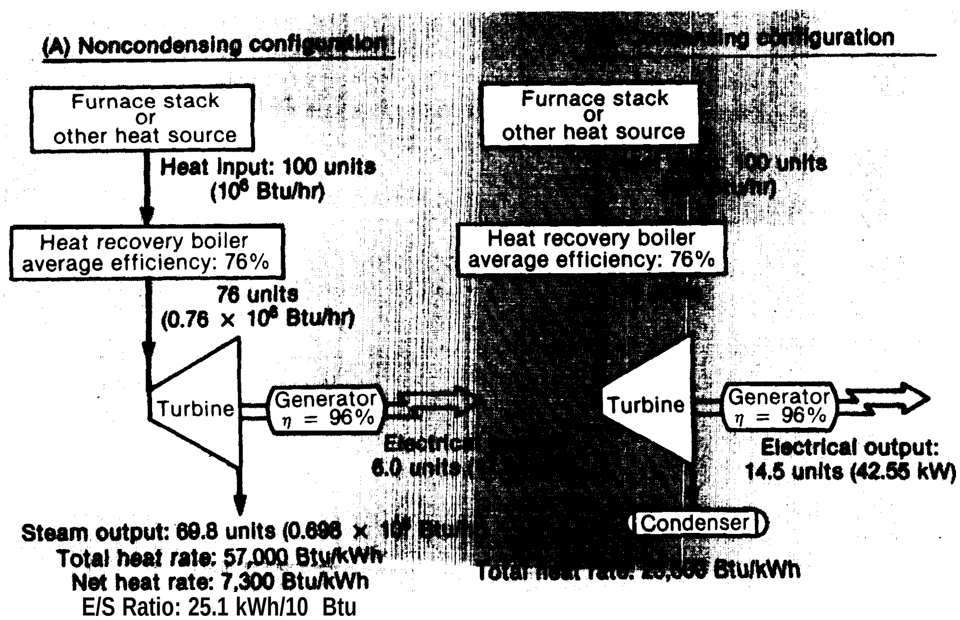


SOURCE: Resource Planning Associates, *Cogeneratlorr: Technical Concepts, Trends, Prospects* (Washington, D. C.: U.S. Department of Energy, DOE/FFU-1703, September 1978).

as far as total fuel use is concerned, because the addition of an organic Rankine bottoming cycle will increase the power output of the system without any increase in fuel consumption.

An analogous situation holds true for steam Rankine bottoming cycles. Figure 31 indicates typical energy balances for both condensing and noncondensing steam Rankine systems. Although

Figure 31 .—Typical Energy Balances for Steam Rankine Bottoming Systems

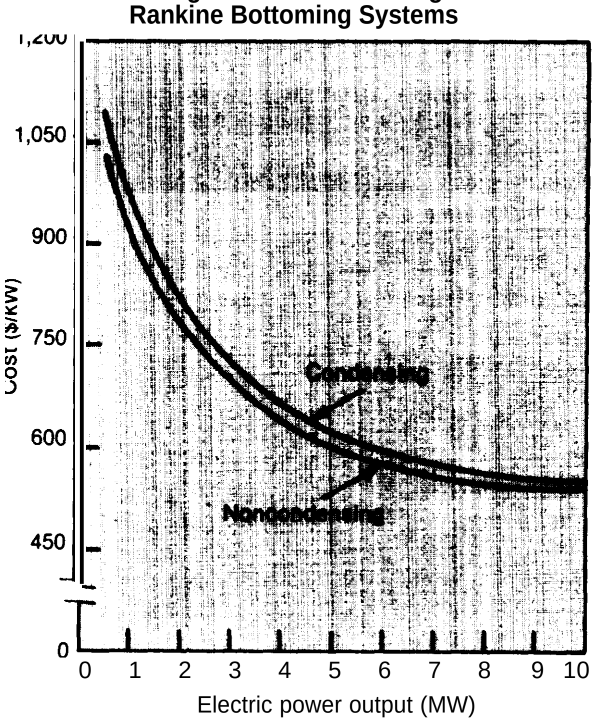


SOURCE: Thermo Electron Corp., Venture *Analysis Case Study—Steam Rankine Recovery Cycle Producing Electric Power From Waste Heat* (Waltham, Maas.: Thermo Electron Corp., TE4231-117-78, December 1978).

figure 31 shows an electric generating efficiency of only 6 percent for the condensing configuration and 14. s percent for the noncondensing, it must be remembered that additional electricity is being generated from heat that normally would have been wasted. Therefore, both configurations will result in substantial fuel savings. Because the noncondensing system produces steam as well as electricity, and hence has a higher overall fuel utilization efficiency, it saves about 150 percent more fuel than the condensing system. The noncondensing system would be used, therefore, when heat requirements and fuel saving considerations override the need for increased electricity production.

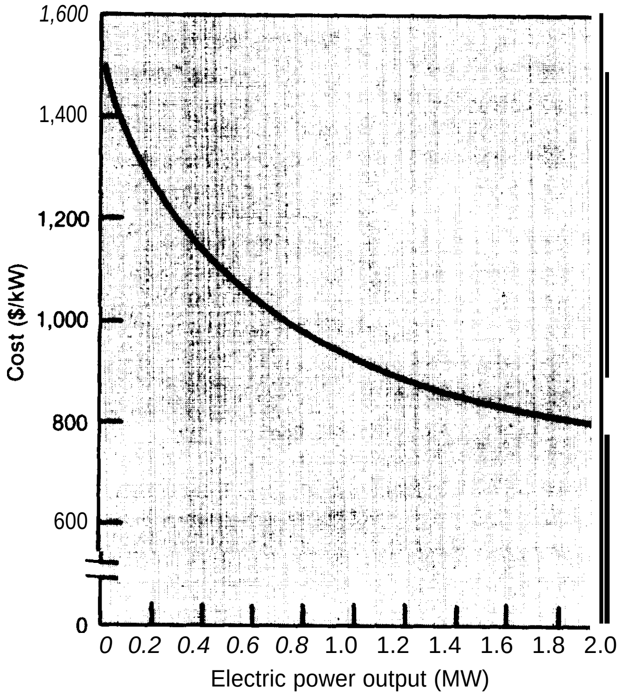
Figures 32 and 33 present estimated installed costs for condensing and noncondensing steam Rankine bottoming systems and for organic systems. The costs of the steam systems are roughly comparable to steam topping cycle cogenerators because most of the components are the same for both types of systems. Installed costs for organic Rankine cycles are more uncertain because mass production of the units has not yet begun. However, available estimates suggest that the organic Rankine cycles will have a higher installed cost than steam cycles, primarily due to the special materials (e.g., stainless steel) needed to prevent corrosion of system components and the precautions that must be taken against leaks of the organic working fluid.

Figure 32.—Estimated installed Costs for Condensing and Noncondensing Steam Rankine Bottoming Systems



SOURCE: Office of Technology Assessment.

Figure 33.—Estimated Installed Costs for Oraganic Rankine Bottoming System



SOURCE: Office of Technology Assessment.

Estimates of variable O&M costs for condensing and noncondensing steam bottoming systems up to 3 MW are presented in table 25. For larger units, variable O&M costs are estimated to be be-

Table 25.-Estimates of Steam Bottoming Cycle Operation and Maintenance Costs

Condensing		Noncondensing	
MW	Mills/kWh	MW	Mills/kWh
0.5	6.86	0.5	6.17
1.0	4.57	1.0	5.03
1.5	4.17	1.5	4.17
2.0	3.87	2.0	3.71
3.0	3.71	3.0	3.71

SOURCE: Thermo Electron Corp., *Venture Analysis Case Study—Steam Rankine Recovery Cycle Producing Electric Power From Waste Heat* (Waltham, Mass.: Thermo Electron Corp., TE4231-117-78, December 1978).

tween 3 and 5 percent of the installed cost. Annual fixed O&M costs are approximately $1 .60/ kw of installed capacity.

Fuel Cells

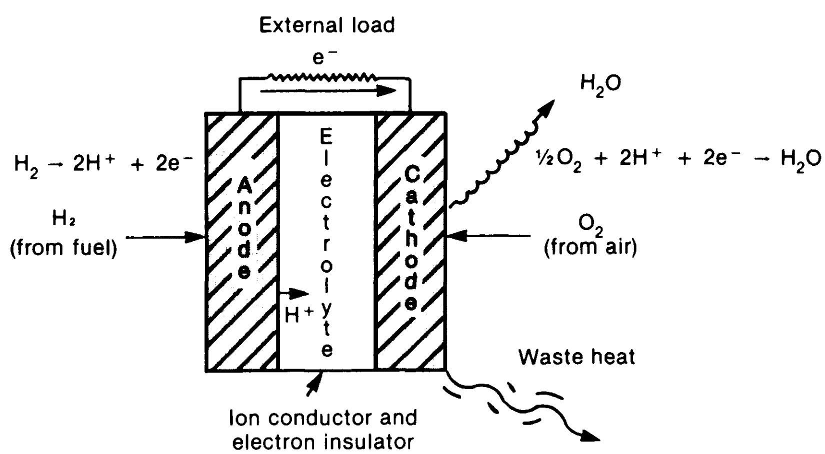
A fuel cell is an electrochemical device that converts the chemical energy of a fuel into electricity with no intermediate combustion cycle (see fig. 34). Hydrogen and oxygen react to produce water in the presence of an electrolyte and, in doing so, generate an electrochemical potential that drives a current through an external circuit. In addition, the reaction produces waste heat. The hydrogen required for the ceil is obtained from fossil fuels, usually methane, CH_4. Because methane occurs naturally only in natural gas, fuel conversion is necessary if coal or biomass are the ultimate sources of the hydrogen. Fuel cells may be attractive for industrial and commercial cogeneration or for utility peaking applications because of their modular construction, good electric load following capabilities without a loss in efficiency, automatic startup and shutdown, low pollutant emissions, and quiet operation. An individual fuel cell has an electric potential of slightly less than 1 volt (determined by the electrochemical potential of the hydrogen and oxygen reaction), but single cells can be assembled in series to generate practically any desired voltage, and these assemblies, in turn, can be connected in parallel to provide a variety of power levels (e.g., 40 kW to 25 MW). A fuel cell powerplant (see fig. 35) includes the cell stack, an inverter (to convert direct current to alternating current), and a fuel processor (to remove impurities from the hydrocarbon fuel and convert it to pure hydrogen). The recovered thermal energy in a fuel cell cogenerator can be either all hot water, or part steam and part hot water depending on the pressure.

The only fuel cell technology currently operating commercially is based on a phosphoric acid electrolyte operating at 350° F. In general, acid systems are favored because they do not react with carbon dioxide and may thus use air as the source of oxygen. Phosphoric acid cells are preferred because water removal is relatively easy to control in these systems. However, phosphoric acid fuel cells depend on platinum catalysts. The present demonstration fuel cell powerplants require a platinum catalyst loading of approximately 6.2 grams per kilowatt of electric power output (27), which, at today's prices, adds $65 to $75/kW to the cost of the fuel cell. A production level of 750 to 1,000 MW of phosphoric acid fuel cells per year (the level one developer suggests will be achieved in the next 10 to 15 years) would

Figure 34.—Schematic Diagram of a Fuel Cell

The elemental fuel cell model

$H_2 + ½O_2 \rightarrow H_2O$



SOURCE: Mathtech, Inc., *An Analysis of the Application of Fuel Cells in Dual Energy Use Systems, Volumes I and II* (Palo Alto, Calif.: Electric Power Research Institute, EM-981 and EM-981-SY, February 1979).

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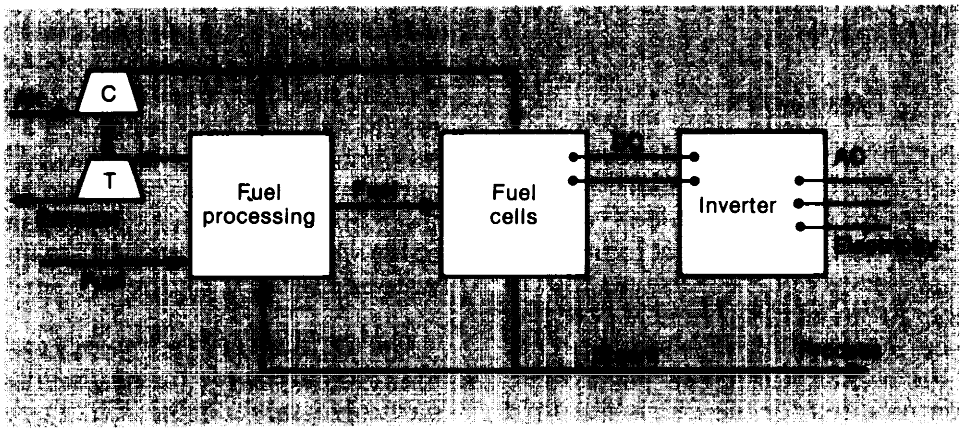
Figure 35.—Schematic of a Fuel Cell Powerplant



SOURCE: United Technologies Corp., *Cogeneratlon Technology Alternatlve Study (CTAS) – Volume VI* (Cleveland, Ohio: National Aeronautics and Space Administration, Lewis Research Center, and Washlngton, D. C.: U.S. Department of Energy, DOE/NASA/OO~OH-6, January 1980).

correspond to approximately 4.7 to 9.3 tonnes of platinum annually, or around 35 to 70 percent of domestic platinum production (including recycling) in 1979, and 3.5 to 7.5 percent of total U.S. consumption in 1979 (9). Because of the small amount of domestic platinum reserves, and limited U.S. refinery and recycling capacity, it is likely that a significant increase in platinum demand for fuel cells would be supplied from foreign sources—primarily South Africa and the U.S.S.R. —and could lead to increases in the price of platinum. R&D efforts are underway to reduce the platinum loading needed for fuel cells (developers estimate future requirements to be about 1.9 grams per kilowatt), to synthesize catalysts that do not depend on platinum, and to develop advanced cells based on molten salt electrolytes (9).

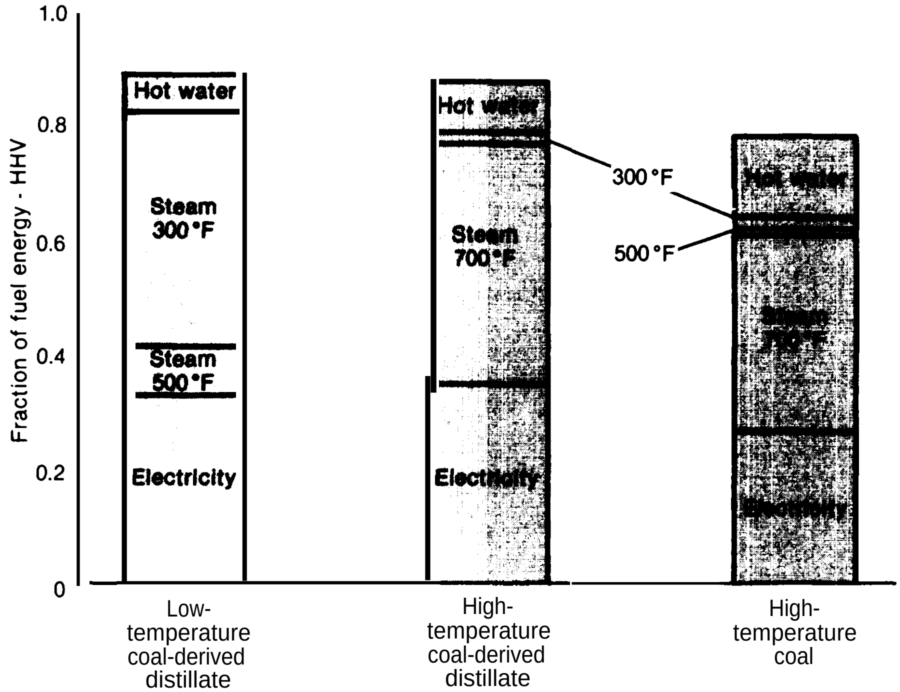
A second limitation of phosphoric acid fuel cells is that hydrogen is the only fuel that can be oxidized at acceptable power levels in the cell, and a clean fuel (e.g., methane or naphtha—a light petroleum distillate) is required to generate the hydrogen. Advanced phosphoric acid cells may be able to use desulfurized No. 2 fuel oil as the source of hydrogen. Second generation molten carbonate electrolyte fuel cells, using advanced fuel conversion technology, would make less stringent demands for a clean fuel, and possibly could be integrated with coal gasifiers.

Developers of fuel cells estimate an installation leadtime of 1 to 2 years for cogenerators based on either the phosphoric acid or molten carbonate cells (assuming mass production). useful service lives are projected to be 10 to 15 years. Maintenance requirements are uncertain due to the limited experience with demonstration plants, but average annual availability is expected to be around 90 percent.

The overall chemical reaction in a fuel cell defines the maximum electric energy that it can produce. Because no thermomechanical work is involved, the energy conversion efficiency is not limited by the Carnot cycle. However, voltage losses are associated with internal resistance, mass transport limitations, and the kinetics of the electrode reactions. Electric generating efficiency ranges from 30 to 40 percent, depending on operating temperature and fuel quality (see fig. 36). At half-load operation, electric generating efficiency equals or even exceeds the efficiency at full load. Thus, fuel cells could be installed for load following duty without a loss in efficiency in order to enable other types of generators to operate at their most efficient rates. E/S ratios for fuel cells are relatively high–from 240 to 300 kWh/MMBtu.

The installed costs for fuel cell powerplants are currently too high to compete with other elec-

Figure 36.-Representative Performance of Fuel Cell Powerplants



SOURCE: United Technologies Corp., *Cogeneration Technology Alternative Study (CTAS)— Volumes I-VI* (Cleveland, Ohio: National Aeronautics and Space Administration, Lewis Research Center, and Washington, D. C.: U.S. Department of Energy, DOE/NASA/0030-80/1-6, January 1930).

tric power generating systems (e.g., a 4.8-MW demonstration plant, being built in New York City, will cost $60 million, or an equivalent of $12,500/kW)." Fuel cell developers project that total installed costs should range from $520 to $840/kW of electrical capacity once the technology is being produced on a large scale (see fig. 37). It is likely that between 500 and 1,500 MW of fuel cells will have to be produced before the "learning curve" price reaches a target level of $350/kW for the fuel cell prime mover alone. As shown in figure 37, the cost of a fuel cell prime mover is not affected significantly by the capacity rating. However, substantial economies of scale are observed with the balance-of-plant costs per kilowatt, including fuel handling costs and electric and control system costs.

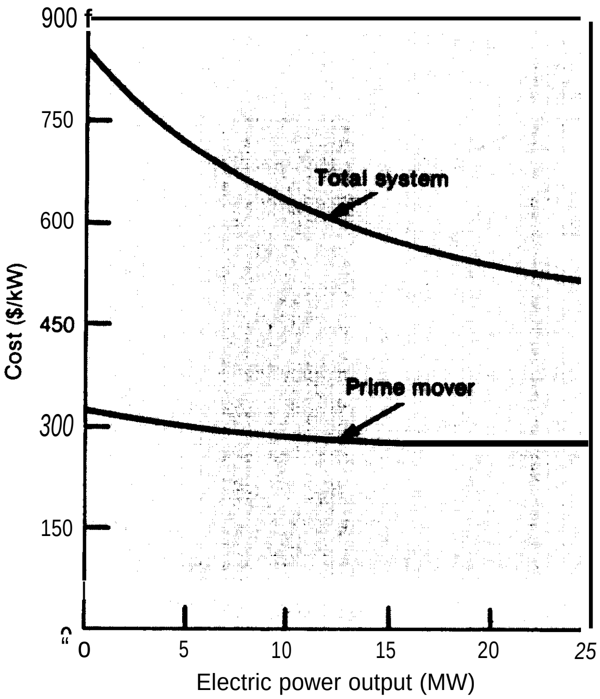
Estimates of variable O&M costs for both types of fuel cells fall within the range of 1.0 to 3.0 mills/kWh. Fixed annual O&M expenses may range from $0.26 to $3.3/kW installed capacity,

Stirling Engines

Stirling engines are a potentially advantageous alternative to diesel, combustion turbine, and steam turbine cogenerators due to their potentially higher thermal efficiency, greater fuel flexibility, good part-load characteristics, low emissions, and low noise and vibrations. Figure 38 shows a schematic of a Stirling cycle engine. Gas (e.g., hydrogen, helium) entrapped by a piston alternately is compressed and expanded to turn a crankshaft. Because the pressure during the hot expansion step is significantly greater than during the cool compression step, there is a net work output from the engine.

Historically, Stirling engines have been investigated for their potential use in automobiles, so developmental work has been directed toward smaller engines, which currently are available in a size range of 3 to 100 kw. A 350-kW Stirling engine is under design, and developers expect

Figure 37.– Future Estimates of Total Installed Costs for Fuel Cell Powerplant Systems

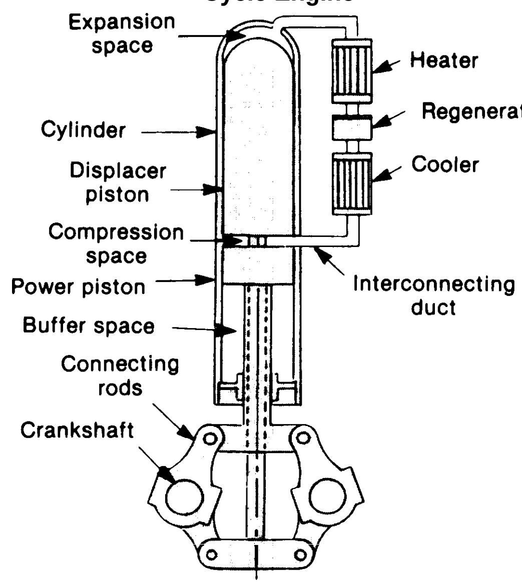


SOURCE: Office of Technology Assessment.

capacities up to 1 to 1.5 MW, with service lifetimes of 20 years to be available by 1990. Although installation leadtimes are hard to predict at present, they could range from 2 to 5 years if and when Stirling cycle cogeneration systems become commercial.

Because Stirling engines are still in the development stage, information about their maintenance and reliability is not readily available, but developers project maintenance requirements (and thus average annual availability) to be comparable to diesels and combustion turbines. Due to the external combustion, closed-cycle configuration of Stirling engines, its moving parts are not exposed to the products of combustion, and the wear and tear on the engine should be minimal. However, Stirling engines do require a complex system of piston rod seals and surface barriers to contain the high-pressure hydrogen and prevent oil from leaking into the working gas space. The durability of the piston seals, which are exposed to a pressure differential of several thousand pounds per square inch, is a recognized reliability

Figure 38.-Schematic of a Stirling Cycle Engine



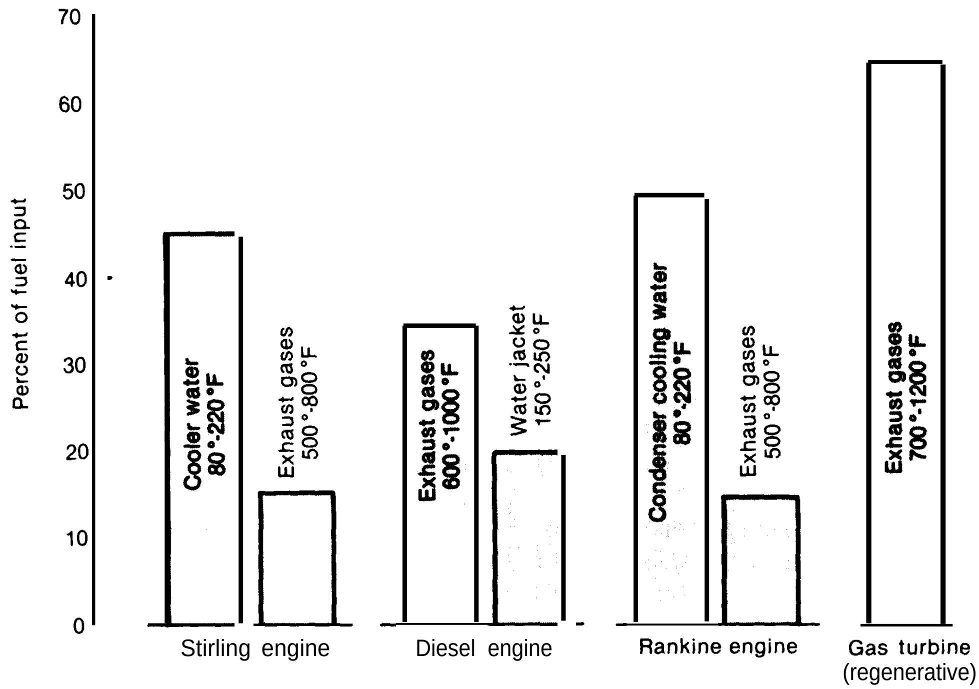
SOURCE: *Application of Solar Technology to Today's Energy Needs, Volurnes / and//* (Washington, D. C.: U.S. Congress, Office of Technology Assessment, 1978).

issue, and the seal systems must be improved before Stirling engines can be used widely.

A major advantage of the Stirling engine is that its external combustion system enables it to use a wide variety of fuels, including coal, coal-derived gases and liquids, municipal solid wastes, and possibly biomass-derived fuels such as wood chips and biogas. In addition, Stirling engines can change fuels without adjustment to the engine, interruption of its operation, or loss of either power or efficiency. This flexibility will allow Stirling engines to be used as components of solar energy systems, as adjuncts to fluidized bed combustors and nuclear reactor systems, etc.

A second advantage of Stirling engines, relative to available cogenerators, is their greater efficiency. The Stirling cycle is much closer to the Carnot cycle than are the Rankine or combustion turbine cycles, and Stirling engines have one of the lowest percentages of waste heat, and thus one of the highest overall fuel use fractions of any heat engine. Figure 39 shows how waste heat available from Stirling engines compares with waste heat from other engine types. The overall efficiency of Stirling engines is relatively independent of system size; electric generating efficiency and

Figure 39.—Waste Heat Availability From Different Engines

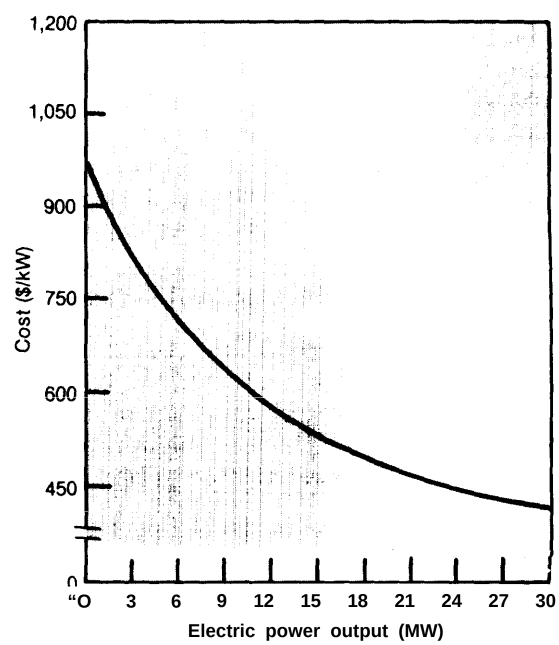


SOURCE: T. J. Marciniak, et al., An Assessment of *Stirling Engine Potential in Total and Integrated Energy Systems* (Argonne, Ill.: Argonne National Laboratory, ANL/EN-76, February 1979).

energy losses remain constant—all that changes is the composition of the waste heat (hot water and steam percentages) (55). Present full-load electric generating efficiency is similar to that of diesel cogenerators (35 to 40 percent). However, as development efforts increase the heat input temperature of Stirling cycles (e.g., through improved metals or ceramic coatings in the heater heads), efficiencies approaching so percent may be obtained over a wide output range (a few kilowatts to several megawatts). Part-load performance of current Stirling engines is equivalent to full-load efficiency, and thus is superior to that of available prime movers. E/S ratios also are very high–from 340 to 500 kWh/MMBtu.

It is difficult to give precise cost estimates for Stirling engines because they are not yet available commercially. Current installed cost estimates for large industrial Stirling engines are approximately 20 percent higher in cost than comparably sized diesel engines (from $420 to $960/kW; see fig. 40). As with fuel cells, successful development work and mass production would be required to

Figure 40.-Future Installed Costs for Stirling Engine Cogenerator Powerplants (extrapolated to 30-MW scale)



SOURCE: Office of Technology Assessment.

realize these costs. Thus, Stirling cycles could be competitive with other cogenerators if their engine efficiency reaches the target of 40 to 45 percent. Otherwise, installed costs would have to be reduced even further before Stirlings could be considered competitive.

Due to the limited operating experience with Stirling engines, no O&M cost data are available. A preliminary estimate of variable O&M costs is 8.0 mills/kWh (higher than for most prime movers) (2), while annual fixed O&M costs are estimated to be $5.O/kW.

USE OF ALTERNATIVE FUELS IN COGENERATION

Cogeneration's ability to reduce the use of premium fuels (oil and natural gas) depends on its fuel use flexibility. If cogenerators use nonpremium fuels (e.g., coal, synthesis gas, biomass, industrial or municipal waste) at the outset, or have the capability to switch readily to such fuels, their viability obviously will be enhanced. However, of the available cogeneration technologies described in this chapter, only steam turbines can burn nonpremium fuels directly. Although R&D efforts are underway to improve the fuel flexibility of other available cogenerators (e.g., advanced combustion turbines and diesels), these improvements may not become commercial until the late 1980's or early 1990's. Similarly, advanced prime movers (such as Stirling engines) that can use alternative fuels are not likely to be widely available for 5 to 10 years. As a result, many potential cogenerators are looking to alternative fuel combustion or conversion systems that can be used in conjunction with current cogeneration technologies to increase fuel flexibility. Two types of such systems—fluidized bed combustors and gasifiers–are discussed below. The use of these systems in industrial, commercial, and rural cogeneration applications is discussed in chapter 5.

Fluidized Bed Combustion Systems*

In fluidized bed combustion, coarse particles of fuel (about 1/4 inch in diameter) are burned in a bed of limestone or dolomite at temperatures of 1,500° to 1,750° F. The fuel and limestone (or other material) are injected into the bed through pipes that are arranged to distribute the fuel evenly throughout the bed area. Feeding is continuous to ensure steady combustion conditions. The fuel particles are kept in suspension and in turbulent motion by the upward flow of air, which is injected from the bed bottom and passed through a grid plate designed to distribute the air uniformly across the bed. During combustion, the system resembles a violently burning liquid and the bed of particles is considered to be "fluidized. " This fluidized state of the burning fuel produces extremely good heat transfer characteristics both among the agitated particles and in the heat transfer surfaces immersed in the bed. Residual materials are drained from the bed continually to allow for steady operating levels.

There are two major types of fluidized bed combustors. In atmospheric fluidized beds (AFBs), fuel combustion occurs at atmospheric pressures. In pressurized fluidized bed (PFB) systems, a pressurizing gas turbine elevates pressures in the combustion chamber to 10 to 15 atmospheres. The pressurized system allows a more compact boiler design and should produce fewer emissions than AFBs. However, development of the PFB is behind that of the AFB, and its availability will follow AFBs by several years.

AFBs are commercially available in sizes that produce from 50,000 to 550,000 lb of steam per hour, which corresponds to 5- to 55-MW electricity generating capacity (7). A 200-MW demonstration plant currently is under construction by the Tennessee Valley Authority (TVA), and is expected to come on-line by 1987. TVA estimates that a 800-to 1,000-MW plant could be built and

*Unless otherwise noted, the material in this section is from ICF, Inc. (26).

in operation by 1991. Because of the lack of construction and operating experience with fluidized beds beyond a 10-MW capacity, however, potential users currently are reluctant to install larger systems.

Only 10 PFB systems are either planned or in operation around the world, the largest being a 30-MW unit currently operating in Great Britain. No commercial vendor of pressurized systems has been identified, and, as mentioned previously, the availability of pressurized systems is expected to be several years behind that of atmospheric systems (7).

The space requirements for atmospheric and pressurized fluidized beds are drastically different. The pressurized combustion process allows for a more compact boiler design, which significantly reduces its space requirements. The area required for a PFB system is approximately one-fifth that of an AFB of equal thermal output capacity (23, 55). The smaller area occupied by PFBs will be particularly important for applications where space is limited or very expensive (e.g., in cities).

Fluidized beds can burn coal, wood, lignite, municipal solid waste, or biomass. The primary fuel used to generate electricity with fluidized beds is coal, and all fluidized bed plants currently in operation use coal as their fuel source. Large (800-Mw) fluidized bed plants are now being designed to use Illinois No. 6 coal, which has a relatively high sulfur content (around 4 percent). Fluidized bed boilers can burn such high sulfur coal without flue gas desulfurization because a large percentage of the sulfur (up to 90 percent) is trapped by the limestone particles within the fluidized bed. Flue gas from the fluidized beds flows through cyclone separators that remove 95 percent of the solid matter in the gas streams. Electrostatic precipitators remove the remaining ash to the level required by emission standards.

The ability to burn high sulfur coal economically represents an important advantage of fluidized bed boilers over the conventional coal combustion systems. However, fuel handling requirements for fluidized beds are more complex than they are for conventional coal boilers. Both the coal (or other fuel) and the limestone with which it burns must be pulverized to a size that can be fluidized easily. Moreover, present fluidized beds designed for a particular fuel will require substantial modification of the fuel handling and injection equipment to convert to another fuel. Advanced fluidized bed boilers may be designed so that they can accommodate different fuel types more easily.

Due to the lack of experience in the operation of fluidized bed boilers, information on their maintenance and reliability is limited. Developers expect the reliability of both fluidized bed types to be similar to that of a coal-fired boiler. However, as experience with fluidized bed technology increases, its maintenance requirements may become less stringent than those for current technologies.

R&D for fluidized bed boilers is directed towards overcoming the basic market barriers to their use. Current R&D focuses on: 1) installing larger demonstration plants; 2) determining the reliability, economic, and environmental characteristics of fluidized bed technology; and 3) demonstrating satisfactory erosion and corrosion behavior in the bed.

Gasification

Gasifiers convert solid fuels into a fuel gas, commonly known as synthesis gas, whose fuel components are principally carbon dioxide and hydrogen, with smaller quantities of various other substances. * The gasification process consists of heating or partially burning the solid fuel and, in some cases, reacting the gas or solid with steam. The resultant gas is a low- or medium-energy gas that contains less than about 500 Btu per standard cubic foot (SCF). This gas is not suitable for blending with natural gas (1,000 Btu/SCF), but it can be transported economically over relatively short distances (usually less than 100 miles) in regional pipelines and used for most of the applications for which natural gas is used (e.g., as a boiler fuel, for process heat, for cooking, for space and hot water heating, or as a combustion turbine fuel).

*The gas from air-blown gasifiers also contains considerable amounts of nitrogen from the air used in the process.

This section analyzes the gasification of three solid fuels—coal, wood, and municipal solid waste—to produce a fuel for open-cycle combustion turbine and reciprocating internal combustion engine cogenerators. These solid fuels are analyzed because they are relatively abundant and are suitable for gasification. Combustion turbines and internal combustion engines are discussed because, of the commercially available cogeneration technologies, these currently have the least fuel flexibility, and because they require a relatively small investment for equipment (an important consideration for small, dispersed cogenerators). However, gasifiers also could be used in conjunction with larger systems such as steam turbines or combined cycles (see discussion of industrial cogeneration applications in ch. 5). Differences in the gases from each solid fuel are described first, followed by a consideration of the implications of these differences for combustion turbine and internal combustion engine cogeneration systems.

Coal

Coal can be partially burned with air to produce a low-energy gas (50 to 150 Btu/SCF) or with oxygen and steam to produce higher energy synthesis gas (300 to 400 Btu/SCF). As described below, the low-energy fuel gas is considerably less efficient as a gas turbine fuel than the synthesis gas, and it may be unsuitable as a fuel for internal combustion engines. However, a coal gasifier that produces synthesis gas requires an oxygen generator, which increases the system cost. Furthermore, both low- and medium-Btu gas from coal contains sulfur (hydrogen sulfide), ash, and other impurities that may have to be cleaned from the gas before it is used. Commercially available low-temperature gasifiers also produce a gas that contains some aromatic compounds and other relatively large compounds that can result in particulate when the gas is burned. High-temperature gasifiers are being demonstrated, and the technological obstacles to their production do not appear to be severe.

Wood

Wood has a relatively high oxygen content and can be gasified completely to synthesis gas (300 to 400 Btu/SCF) by heating it (pyrolysis) without the need for an oxygen plant. Pyrolysis usually requires a longer residence time in the gasifier than air-blown gasification, which increases pyrolysis equipment costs, but probably not enough to offset the savings from eliminating the oxygen plant. More rapid pyrolysis gasification is possible, but can result in the formation of considerable quantities of relatively large organic compounds in the gas that would tend to form particulate when burned. Wood gasification also can be accomplished with air being used to partially burn the wood. If properly controlled and designed, air-blown wood gasification can produce a fuel gas containing over 200 Btu/SCF.

Because wood contains sodium and potassium salts, the resultant fuel gas often contains these elements as impurities, which can damage or reduce the life of certain turbine blades. Thus, as with coal gas, wood gas may have to be cleaned before it is used.

Municipal Solid Waste

Municipai solid waste (MSW) contains large amounts of paper, plastic, metals, and other materials. The heavier materials can be separated economically from the paper in MSW, but most plastics cannot. Thus, for practical fuel purposes, MSW is a mixture of paper and plastic.

Like wood, MSW can be pyrolyzed to synthesis gas or partially burned to a lower energy gas in an air-blown gasifier. However, because much of the plastic in MSW contains chlorine (e.g., polychlorinated biphenyl plastics) the resultant fuel gas will contain hydrogen chloride (in aqueous form, muriatic or hydrochloric acid), which is extremely corrosive. Consequently, gasifiers and other equipment in contact with the gas must be constructed of expensive, acid resistant steel. Ceramic-coated metals that can be used in MSW gasifiers are under development. As a result of the problems introduced by plastics, MSW fuel gas currently is not economical. Furthermore, because paper is the only part of MSW that serves as a good gasifier feedstock, MSW gasification only partially solves waste disposal problems.

Combustion Turbines

As discussed in the previous section, reliable and efficient operation of open-cycle combustion turbines requires a high quality fuel that is relatively free of particulate and metallic impurities. None of the fuel gases described above fully satisfies these criteria. Coal gas contains sulfur and some heavy metal impurities, and low-temperature gasification of coal can produce a gas that is high in particulate when burned. Wood gas contains sodium and potassium and, in some cases, may produce particulate when burned. MSW has a much lower sodium and potassium content, but contains corrosive hydrogen chloride. If untreated, all of these fuels can damage commercially available turbines and reduce their useful life. Consequently, extra equipment is needed to purify these gases. The technical problems of turbine lifetime probably can be solved if ceramic coatings for turbine blades are successfully developed. However, environmental controls still would be required to prevent the release of heavy metals (from coal) and particulate (from all fuel types).

The energy content of the gas also can pose problems for combustion turbines. Low-energy gas (perhaps less than 150 to 200 Btu/SCF) can lower the efficiency of combustion turbines. Thus, wood and MSW gasifiers must be properly designed and operated to ensure that the energy content of the gas is greater than 200 Btu/SCF, while coal gasifiers will require oxygen plants to achieve a satisfactory energy content. Combustor design for medium-Btu gas (250 to 500 Btu/SCF) is well developed and use of this gas with gas turbines presents no efficiency problems (47,48).

Although fuel quality must be high in order to prevent damage to turbine blades in open-cycle combustion turbine operation, the use of solid fuels is not necessarily precluded. It is unlikely that coal will be able to be used in this way but recent developments indicate that pulverized wood can be made acceptable. The Aerospace Research Corp. in Roanoke, Va., is designing and building a 3-MW combined-cycle system using an open-cycle gas turbine fueled by pulverized wood (62). The wood is dried to a 25-percent moisture content, and the combustion gases are cleaned using hot gas cleanup technology developed in the British pressurized fluidized bed combustion program. Using these steps, it appears that unacceptable damage to the turbine blades can be avoided. A 17-MW system (also designed by Aerospace Research Corp.) operates at an inlet temperature of 980° C and an exhaust temperature of 510“ C.

While this system shows promise, its acceptance will depend on demonstrated reliability over an extended period. If it is necessary to remove the blades and repair or replace them more often than currently anticipated, the O&M costs could negate the potential economic benefits of using wood directly. Reliability also will depend on durable operation of the hot gas cleanup technology and the burner assembly, which requires a screen to filter out the larger wood particles. These issues should be resolved by the demonstration unit under construction in Virginia.

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engines suffer from some of the same problems regarding fuel gas quality as combustion turbines, but metallic contamination and particulate are more a pollution problem than a technical problem in operating these engines. As mentioned above, hydrogen chloride from MSW plastics can pose a corrosion problem if it is not removed from the fuel gas.

For proper operation of an internal combustion engine, the fuel gas must be cooled to avoid detonation of the fuel. This reduces the energy content of the fuel and thereby increases costs. For wood and MSW, the loss is about 50 percent, but may be lower for medium-energy gas from coal and higher for low-energy gas from coal. !f the waste heat from cooling the gas can be used onsite, this reduction in energy content does not reduce the engine's overall fuel efficiency, but will reduce the electric generating efficiency.

Fuel gas that contains heavy organic compounds can produce gums that increase the maintenance requirements for reciprocating internal combustion engines. The formation of such gums is the most common operating problem with using fuel gas from relatively primitive wood gasifiers in these engines, and the second most common problem with MSW gas (after hydrogen chloride formation). With wood gas, internal combustion engines that operate continuously may require overhauling every 6 to 12 weeks (1,000 to 2,000 hours of operation). Engines that burn gas from moderate- to high-temperature coal gasifiers are more likely to have maintenance requirements similar to those of engines that burn premium fuels (discussed in the previous section).

INTERCONNECTION

The analysis in this report assumes that the cogeneration technologies just described are interconnected with the centralized electric grid, so that the cogenerator may supply power to the grid and use backup power from the grid. However, interconnection with the grid may create problems for the utility system's operations or for the cogeneration equipment itself. As discussed in chapter 3, many State public utility commissions already have jurisdiction over utility connections with customers. In most States, this includes regulation of voltage levels and safety standards. However, in the past the utilities and State commissions have had to be concerned only with regulating power flow in one direction—from utility equipment to the customer. Because interconnected cogeneration will involve power flows in both directions, utilities' and regulatory commissions' tasks in these areas will be more complicated.

If cogenerated power is of a different quality from that distributed on the grid, it may affect the utility's ability to regulate power supply and may result in damage to both the utility's and its customers' equipment. Moreover, large numbers of utility-dispatched dispersed generators could make central load dispatching more difficult. Utilities also are concerned about properly metering the power consumption and production characteristics of grid-connected cogeneration systems, and about the effects of such systems on the safety of utility workers. Finally, all of the above concerns raise questions about liability for employee accidents or equipment damage that may result from improper interconnection.

The Public Utility Regulatory Policies Act of 1978 (PURPA) authorizes the Federal Energy Regulatory Commission (FERC) to issue orders under the Federal Power Act requiring the physical connection of a qualifying cogenerator (or other small power producer) with electric utility transmission facilities and any action necessary to make that connection effective (e.g., increasing the existing transmission capacity or improving maintenance and reliability) (see ch. 3). Under the FERC rules implementing PURPA, utility rates for purchases of power from and sales of power to cogenerators must take into account the net increased costs of interconnection (i.e., compared to those costs the electric utility would have incurred had it generated the power itself or purchased it from the grid), including the reasonable costs of connection, switching, metering, transmission, distribution, and safety provisions, as well as administrative costs incurred by the utility. Each qualifying cogenerator must reimburse the utility for these interconnection costs. The State regulatory commissions are responsible for ensuring that interconnection costs and requirements are reasonable and nondiscriminatory, and for approving reimbursement plans (e.g., amortizing the costs over several years versus requiring one lump-sum payment).

This section discusses the nature of potential interconnection problems for cogeneration, describes some of the technologies that can be used to resolve them, and reviews estimates of the cost of meeting interconnection requirements. Where data specific to cogeneration are not available, analogies are drawn from the relevant literature on wind or photovoltaic systems.

Power Quality

Utility customers expect electric power to meet certain tolerances so that appliances, lights, and motors will function efficiently and not be damaged under normal operating conditions. Power supplied to the grid by an interconnected cogenerator also is expected to be within certain tolerances, so that the overall power quality of the utility system remains satisfactory. Electric utilities are concerned about three types of power quality: correcting the power factor to keep the voltage and current in phase, maintaining strict voltage levels, and minimizing harmonic distortion.

Power Factor Correction

Current and voltage are said to be "in phase" if they have the same frequency and if their wave forms coincide in time. The capacitive and inductive properties of electrical circuits can cause the voltage and current to be out of phase at particular places and particular times. Phase shifts are expressed as the cosine of the fraction (in degrees) of the full 360° cycle of the difference between the voltage and current maximums, called power factor. A power factor of 1.00 means that the current and voltage signals are in phase. A power factor different from 1.00 means that the voltage and current are out of phase, and can be either "leading" if the voltage maximum occurs before the current maximum, or "lagging" if it occurs after. Because the most useful power is delivered when voltage and current are in phase, it is important that the power factor be as close to 1.00 as possible.

Phase shifts are one consideration in setting the demand component of rate structures (see ch. 3). Thus, utilities typically will have one rate for power with a power factor of 1.00 sold to other utilities, another rate for power sold to industrial customers which may have power factors much less than 1.00 and that require the utility to install special monitoring devices, and another rate for power sold to residential customers, where power factor is not measured individually (l).

Utilities (and cogenerators) supply power with two basic types of alternating current (AC) generators—induction generators and synchronous generators (64). An AC generator produces electric power by the action of a rotating magnetic field that induces a voltage in the windings of the stationary part of the generator. The rotation is caused by mechanical means (steam or combustion turbine, diesel engine, etc.) and the magnetic field is created by a current flowing in windings on the rotor. For an induction generator, this current is supplied by an external AC source, such as the electric power grid. For a synchronous generator the rotor current comes from a separate direct current source on the generator itself. As a result, a synchronous generator can operate independently of the electric grid or any other AC power source whereas induction generators cannot. When a cogenerator feeds into a power grid, induction generators can be advantageous because they are less expensive than synchronous generators (22). There are other characteristics of the two types of generators, however, which can negate this cost advantage.

First, synchronous generators have power factors of approximately 1.00 but can be adjusted to slightly leading or slightly lagging, while induction generators always have lagging power factors because they have more inductive than capacitive elements (15,35,64). Second, synchronous generators are more efficient than induction generators. These two points can cause synchronous generators to be preferred for units above a certain power level (about 500 kW), although the precise value depends on the situation (22). Third, care must be taken if there are several cogeneration units on a circuit, as would almost certainly be the case for a utility buying cogenerated power. When a synchronous generator is connected to other generators (either synchronous or induction), separate equipment is needed to synchronize each additional generator with the others. Such equipment is standard but does add to the total system cost.

Most cogenerators that have been installed to date have been larger synchronous machines because they can be used if the grid is disconnected and they offer redundant capacity for those (usually higher demand) customers who need secure power sources, such as hospitals and computer centers (15). However, PURPA provides incentives for all sizes of cogenerators, and thus those customers that can use smaller generators and do not need redundant capacity will have an economic incentive to use an induction generator. As the penetration of these induction cogenerators increases, more inductive elements are added to a particular distribution substation's circuits, resulting in a more lagging power factor. Unless the utility has a leading power factor, this creates three potential problems for the utility:

the capacity of both transformers and switching equipment in the transmission and distribution system may have to be increased to handle the out-of-phase signals; the efficiency of the transmission network may decrease;* and equipment and appliances may overheat and need more frequent overhaul (20).

Utilities normally improve lagging power factors by using capacitors, which may be sited either at the distribution substation or near the customer's load or generator, depending on the cause of the poor power factor and its magnitude (22). If the poor power factors are caused by smaller customers' equipment, utilities usually pay for the correcting capacitors, while larger customers often are required to pay for their own power factor correction. Most utilities have guidelines that state the minimum power factor allowed, usually 0.85 lagging (46). If a customer fails to maintain this minimum, utilities may ask the customer to install and pay for the necessary corrective capacitors. ** Traditionally, few utilities have leading power factors, because most utility circuits (and most appliances and motors) have more inductive elements than capacitive elements.

Similar policies will apply to cogenerators. Thus, many utilities are supplying capacitors (out of the overall transmission and distribution system) for smaller cogenerators, while requiring larger ones to pay for their own capacitors under the theory that there will be fewer substations with a significant cogeneration penetration. Thus, the avoided substation capacity becomes part of the utilities' avoided cost under PURPA and is credited to the cogenerator (see ch. 3).

*Other sources have indicated that the increase in utility transmission and distribution efficiency compensates for the decrease in power factor from induction generators (40). Efficiency is increased because more power is produced onsite and therefore less power is transmitted and less power is lost due to inefficiencies in the transmission and distribution system.

**Salt River Project has monitored an interconnected photovoltaic array for an entire year and calculates that its average lagging power factor is about 0.50 (10). However, the array produces direct current (DC) power and uses an inverter to convert the DC power into AC. Since cogenerators produce AC power, no inverter is necessary. Inverters have a poorer power factor than most induction generators.

Southern California Edison's guidelines are typical of those utilities that have set guidelines:

> Installations over 200 [kW] capacity will likely require capacitors to be installed to limit the adverse effects of reactive power flow on Edison's system voltage regulation. Such capacitors will be at the expense of the [co]generating facility (49).

This expense can be important for smaller cogeneration systems: for example, the cost of capacitors to increase the power factor of a 300-kW generator from 0.70 to 1.00 can range from 1 to 4 percent of the capital cost of the cogenerator. *

However, just the installation of capacitors may not be sufficient. If the capacitors are located near induction generators, the generators may "self excite;" in other words, they may continue to operate even when they are disconnected from the utility power source. This could be a problem for utility lineworkers because the cogenerator could start supplying power and endanger the workers. This is discussed in more detail in the section on safety, below.

Voltage Regulation

In addition to potential problems with maintaining appropriate power factors, utilities also are concerned with regulating voltage. Utilities have many concerns about variations in voltage cycle from the standard cycle, both over long and short time intervals. While some customers can tolerate voltage levels outside of a specified range for very brief intervals (less than a second), any longer term variation will cause motors to overheat and will increase maintenance costs. ** Voltage cycle

*This range assumes that capacitors may cost anywhere from $9 to $40/kVAR (kilovolt-am peres-reactive, a measure of current and voltage handling capability), with the low end of the range representing the cost for capacitors used in the large bulk transmission systems, such as those maintained by American Electric Power; and the high end of the range representing the cost for capacitors used in smaller distribution system applications, such as single-family residence interconnections (29,43). The amount of capacitance needed to correct a power factor of 0.70 to 1.00 is 1.02 kVAR/kW (63). Capital costs are assumed to be $1 ,000/kW for a 300 kW generator (6,61). Thus, the range of costs are 40 X 1,02 = $41/kW to 9 x 1.02 = $9/kW, or approximately between 1 and 4 percent of the capital cost.

**The American Public Power Association's guidelines cite a table from the Estimator's Guide that give recommended voltage ranges over a given day, hour, minute, and second (l).

variations are minimized through the proper design and operation of generators. However, generators do not always function perfectly, and protective "over/under voltage" relays generally are necessary to disconnect the generator if its voltage falls outside of a certain range. These relays usually cost under $1,000, including installation (15,22).

The State regulatory commissions normally require a steady supply of 120 (or 240) volts (+/-5 percent) for residential customers (1). Large commercial and industrial customers often receive their voltage directly from substations or distribution lines, with much higher voltages and different tolerances (see the discussion of transmission and distribution in ch. 3).

Two major analyses are available of potential voltage regulation problems caused by improperly interconnected dispersed generators. One study considers a sample utility with sO percent of its customers generating power with wind machines (14). This study might be considered a "worst case" analogy for cogeneration because the output from the wind machines will change more often than the output of typical (either induction or synchronous) cogenerators. Even with this 50 percent penetration, the study indicates that substation voltage levels would remain within 5 percent of standard levels because:

> . . . [the] addition of small wind systems to a [distribution] feeder will not occur suddenly; rather wind-turbine generators will be installed in small capacities throughout the utility's system and if, by chance, many are added to a particular feeder, the voltage profile will change gradually. [Also] utilities adjust voltage regulation equipment for normal load growth and wind-turbine generators added to a feeder will influence this normal adjustment procedure only slightly (13).

In the second study, the Salt River Project (SRP) installed a transformer on its 37.5-kVA distribution circuits and connected it to two residences (both unoccupied), one of which uses a photovoltaic array, in order to test the effect of the photovoltaic system on other residences connected to the same distribution transformer (12). That study also concluded that voltages would remain within 5 percent of standard (10).

Both of these studies indicate that cogeneration should not present any longer term (i.e., lasting longer than 1 minute) voltage regulation problems for utilities. However, sudden and more brief changes in power system voltages can also occur in utility systems—especially when large power consuming equipment is turned on and off (such as the cycling of air-conditioner compressors and refrigerators). These changes are caused by the large amount of current that is needed to startup these motors, thereby removing some power normally used for the remaining load on the circuit. Because these large surges of power can temporarily dim lights, these changes are called "voltage flicker."

Utilities usually confine voltage flicker problems to the customer's own system by requiring some large commercial and industrial customers to use a "dedicated" distribution transformer that connects the customer's load directly to a higher voltage distribution line, substation, or, in some cases, the higher voltage transmission network.* Because of this policy, voltage flicker and regulation effects of cogenerators are extremely site- and circuit-specific and it is difficult to make any general statements except that most of the commercial and industrial facilities that are potential cogenerators probably already have a dedicated transformer (15). Therefore there would be no additional cost for voltage regulation if these customers were to install cogenerators. One way for cogenerators to get around this problem is to install synchronous generators, which already include voltage regulators.

However, if a potential cogeneration facility does not have a dedicated transformer and uses an induction generator (e.g., smaller commercial and residential customers), the cost involved in installing a transformer could be equal to all other interconnection equipment costs combined, and therefore could be a major disincentive to cogeneration. In general, however:

> dedicated transformers are not a valid issue for any but the smallest cogenerators or small

*The connection depends on the size of the customer's load (usually, the larger the customer, the higher the voltage connection), the density of the surrounding area (transformers would be needed in rural areas with spotty concentrations of loads, and in very high density urban areas), and on other site- and distribution-circuit-specific conditions.

power producers (less than about 20 kw) and, of those, only the ones installed in high density areas where non-dedicated transformers are the usual method of service. where a dedicated transformer is needed, the issue usually is] settled through negotiations between the utility and the customer with the requirement for a dedicated transformer being waived if it would be impractical (15).

Even though dedicated transformers may not bean issue for many cogenerators, most utilities protect themselves by including a clause in their interconnection agreement that says:

[f high or low voltage complaints or flicker complaints result from operation of the customer's [co]generation, such generating equipment shall be disconnected until the problem is resolved (49).

The interim guidelines published by the Rural Electrification Administration state that "no induction generators larger than 10 kW should be permitted on single phase secondary services . . . due to possible phase unbalances and voltage flicker" without the electric cooperative first studying the situation to ensure that adequate and reliable service to all members will be maintained (52).

Harmonic Distortion

A third utility concern related to power quality is harmonic distortion. Occasionally, other frequencies besides the standard 60 cycles per second are transmitted over the power system, usually due to the use of an inverter that converts DC power into AC power. The distortions are called harmonics because they have frequencies that are multiples of 60. These distortions may be made up of several harmonic frequencies or a single strong frequency. A 60 cycle-per-second power signal accompanied with many other harmonic signals may cause several problems for the utility:

Excessive harmonic voltages [and currents] may cause increased heating in motors, transformer relays, switchgear*/fuses, and circuit breaker ratings, with an accompanying reduction in service life, or distortion and jitter in TV pictures, or telephone interferences. Also, excess harmonics may produce malfunction in systems using digital and communications equipment (20).

Other possible problems caused by excessive harmonics are the overloading of capacitors, malfunctioning of computers, and errors in measuring power at the customer's kilowatthour meter (12,25).

What constitutes "excessive" harmonics is not well defined. There is no agreement on the exact ratio of distorted signals to the standard signal, and a great deal of research is underway to determine this ratio precisely. SRP has collected data on the operation of an interconnected photovoltaic array for over a year:

But, SRP feels further study is needed on the level of harmonics that occurs naturally on a utility system, the limits that must be placed on harmonics required to prevent adverse effects on equipment and appliances, and on whether certain harmonic frequencies are more harmful [to the utility system] than others (4 l).

While further research is underway, both the Electric Power Research Institute (EPRI) and the American Public Power Association (APPA) have recommended maximum percentage limits for total systemwide harmonic distortions for both current and voltage signals (as well as limits for any one single source and single voltage or current frequency). EPRI (20) suggests 5 percent for current harmonics, and 2 percent for voltage, while APPA (1) suggests 10 percent for current and 2 percent for voltage. *

In the past, most of the major problems of harmonics have occurred with the normal operation of inverters, rather than any malfunctioning of conventional induction or synchronous generators (15). Since inverters have a high capital cost, they rarely are used and their present impact on utility systems is small in most cases. Because cogenerators produce AC power at the standard power system frequencies and, therefore, do not use inverters, and because these generators are not normally a significant harmonic source, most

*Switchgear (used in this citation and throughout this report) refers to all of the necessary relays, wiring, and switches that are used in interconnection equipment.

*Several municipal utilities already have adopted APPA's recommendations for harmonics, such as the Salt River Project in Phoenix.

utility engineers feel that harmonic distortions will not increase when cogenerators are interconnected to utility systems (43).

Summary of Power Regulation Problems

Smaller cogenerators (under 20 kW) may not be able to afford the necessary power regulation equipment in connecting to the centralized grid, including capacitors to correct power factor (if required) and dedicated transformers to regulate voltage (if not already in use). However, these smaller units may have little or no adverse effect on overall system power quality, according to one study looking at wind machine penetration. Thus, a utility, when considering each particular case of a smaller cogenerator, may be able to exempt the cogenerator from the requirements for expensive interconnection equipment. Larger grid-connected cogenerators might need to install capacitors to correct for power factor—if they use induction generators— but probably will have a dedicated transformer already.

Even though all of the power quality effects of interconnected cogeneration are very site-specific, most of the evidence gathered so far indicates that neither excessive harmonic distortion nor objectionable voltage flicker will be caused by adding any size of cogenerator to the centralized system.

Metering

Three types of metering configurations can be used to measure the amount of energy consumed and produced by dispersed generators. The first uses the simple watthour meter that is commonly found outside of most homes today and that costs approximately $30* (1,29). When a cogenerator is producing power that is sold back to the utility, the watthour meter simply runs backward (even though the meter running backwards can be off as much as 2 percent in measuring power) (l). As a result, the meter will measure only net power use, thus assuming that there is no difference between the utility's rates for purchasing cogenerated power and its retail rates. If these rates are different (as they are likely to be with most utility systems) then two watthour meters can be used, one that runs in the reverse direction of the other, with the first meter to measure power produced by the cogenerator and the second (equipped with a simple detente or rachet that prevents the reverse rotation of its induction disk) to measure the customer's power consumption. This configuration is recommended by the National Rural Electric Cooperative Association interim guidelines, unless the individual electric cooperative prefers a different metering system (52).

The third configuration uses more advanced meters to measure a combination of parameters, including power factor correction, energy, and time-of-use. * Some utilities are asking customers to install these advanced meters in order to understand the relationship between the cogenerator and the central power system better, and to collect the best data possible to help determine future interconnection requirements (such as **information on power factor requirements and peak demands) and to decide how to price buyback and backup** power. These more sophisticated meters can cost $300 or more each (29). In some cases, such as with Georgia Power, the utility is supplying the advanced meters and paying for the collection and analysis of data (30). In others, such as with SRP (46) and Southern California Edison, ** the customer may be asked to pay for the meters (either as a one-time charge or in several types of monthly installment plans).

Controlling Utility System Operations

Most utility systems have a control center to coordinate the supply of power with changes in demands. Such coordination involves both day-

*More complicated (and more expensive) three-phase watthour meters may be used where three-phase power, which consists of three (current and voltage) single-phase signals, each out of phase with the others by 120°, is supplied to larger commercial and industrial customers.

*Theordore Barry & Associates (52) provides many examples of these more advanced configurations, and includes the cost (excluding instrument transformers) for different combinations of single-phase meters.

* *southern California Edison already bi lls its larger customers (either those installations with greater than 200 kW of generation or those with less than 200 kW generation with greater than 500 kW of load) using time-of-day meters. Customers that become cogenerators who do not have time-of-day meters already will not be required to install them by Edison (15).

to-day operations, including dispatching generators and monitoring load frequency and power flows over the transmission and distribution network, and longer term tasks needed to schedule unit commitments and maintenance (25). If load changes are not anticipated correctly by system controllers, transformers may become overloaded and circuit breakers may open the line, possibly causing power reductions or interruptions for customers that are connected to that transformer. Cogenerators have the potential to affect two types of system operations: generation dispatch and system stability.

Generation Dispatch

Many utilities are concerned that large numbers of cogenerators will overload system dispatch capabilities, including the ability to anticipate transformer overload conditions (43). If the utility feels the cogenerated electricity needs to be dispatched centrally, it could require a connection via telemetry equipment between the cogenerator and the control center, so that the system controllers can turn cogenerators on and off according to the overall needs of the utility system (36). This telemetry equipment is costly, and probably would be used only with very large cogenerators.

One study has looked at potential dispatch and control problems for a large penetration of wind generators and has concluded that with approximately half of the load using grid-connected wind turbines, the dispatch and control errors of the system controllers would not increase significantly (14). Because wind machines would have greater fluctuations of power output than cogenerators, large numbers of cogenerators should pose even fewer control problems.

For smaller cogenerators, it is unlikely that the utility would require any dispatch control. Rather, these smaller units can be treated as "negative loads," in which case the controller would subtract the power produced by the dispersed sources from his overall demand and dispatch the utility's central station generation to meet the reduced demand. Negative load treatment probably will be more advantageous to the utility system than dispatch telemetry because the overall impact of smaller cogenerators on system loading and voltage conditions may be quite limited (44).

Negative load scheduling works well for those utilities that already have a few cogenerators online, and some utility transmission planners believe that even much larger numbers would not cause problems for the utility. That is, as more cogenerators are added to a particular distribution substation, the utility would continue to use negative load scheduling. (The utility would need to increase the capacity of the transmission and distribution lines–equivalent to upgrading the capacity of its lines as a developer adds more homes to a subdivision.) Because conditions are so site-specific, it is difficult to generalize and put forth guidelines, and each utility's situation must be considered individually to determine the appropriate requirements (44).

System Stability

Stability refers to the ability of all generators supplying power to stay synchronized after any disturbance (such as after a fault on part of the power system) (25). At its most extreme, a disturbance may cause a loss of synchronization for the entire power system (resulting in a possible systemwide blackout), or may alter the flow of power within the system and cause selected blackouts.

Not much is known about the effects of a significant number of cogenerators on a system's stability. Utilities are concerned that large penetrations of small, dispersed sources of power could contribute to unstable conditions. Some analysts (25) cite a 5 to 10 percent penetration of the service area (with photovoltaic systems) as the definition of "large penetration," while others cite much higher figures. One study by Michigan State University (cited in 25) shows that wind turbines cause fewer stability problems for the overall utility system than variations in weather (such as the movement of storm fronts). Further research on the effects of cogenerators on system stability is needed before any conclusions can be made, however.

Safety

A **major concern with interconnection of dispersed generators is the safety of utility employees working on transmission and distribution lines. During routine maintenance or repairs to faulty lines, lineworkers must disconnect the generation** source from **the service area, and establish a visibly open circuit. Also, before starting any repairs, they must ground the line and test it to ensure that there is** no power flowing in the line. The Occupational Safety and Health Administration publishes a series of guidelines for utilities on these procedures (OSHA subpt. V, sees. 1926.50 through 1926.60),

Disconnecting and grounding the lines is relatively simple when the generation system is centralized and there are few sources of supply. However, with numerous sources of power supply (as with grid-connected cogenerators) the disconnect procedure becomes more complicated and extra precautions may be needed: the utility must keep careful accounts of what dispersed equipment is connected to the system, where that equipment is located, what transmission lines and distribution substations it uses, and where the disconnecting switches are located. To simplify these procedures, many utilities have asked cogenerators to locate their disconnect switches in a certain place, such as at the top of the pole for the distribution line going into the customer's building (30).

Disconnecting and reconnecting a cogenerator is not so simple as just turning the switch off and on, because the cogenerator must be synchronized and brought up to the standard frequency before coming back on-line with the centralized system. Without this synchronization, both the cogenerator and the customers' appliances could be damaged.

However, the normal operation of circuit breakers that have disconnected a line to clear a fault is to reclose automatically after a fraction of a cycle. * If a problem on the line is still present, a cogenerator also will need to be concerned about this reconnection. Most utilities require protective equipment that can disconnect the cogenerator from the line before any reclosing can occur (49).

Another problem with disconnecting cogeneration equipment is self-excitation of the generators. When an induction generator is isolated from the rest of the grid (because of a downed line or a breaker opening the line), the absence of the grid-produced power signal usually will shut down the generators. However, if there is sufficient capacitance in the nearby circuits to which the generator is connected (e.g., power factor correcting capacitors), the induction generator may continue to operate independently of any power supplied to the grid. * The power signal produced by the isolated self-excited induction generator will not be regulated by the grid's power signal and the customer's electricity-using equipment may be damaged. More importantly, an isolated induction or synchronous cogenerator that reenergize on the customer's side of a downed transmission or distribution line, could endanger utility workers. Self-excitation is less of a problem with synchronous generators (which will continue to operate independently of the grid).

There are two ways to prevent self-excitation problems. First, the utility can put the corrective capacitors in a central location, in which case disconnecting a cogenerator also will disconnect the capacitors and reduce the possibility of self-excitation. Southern California Edison recommends this method for smaller (less than 200 kW) cogenerators (49). Alternatively, voltage and frequency relays and automatic disconnect circuit breakers can be used to protect both the customer's equipment and utility workers.

In summary, while extra precautions must be taken to ensure the safety of utility crews, none of these precautions is difficult to implement and,

***One consultant cites the following example:**

An oil circuit recloser (OCR) responds to a fault, such as a tree limb against a conductor, by deenergizlng the line for approximately one-quarter to one second, and then recloses to restore service In the event the fault was temporary. This operation may be repeated up to three times, depending on the recloser setting, before the OCR [leaves] the line deenergized (52).

Such alternate connecting and disconnecting can damage the cogenerator.

***One consultant calculated that this self-excitation is possible with wind turbines (1 4). A 100-kW machine capable of supplying half of the customer's load, connected to the capacitors needed to correct a 0.75 power factor to 1.00, will self-excite and supply 30 volts to that load—25 percent of the standard 120 volts.**

when properly carried out, will minimize the potential for danger to utility personnel.

Liability

Despite the protective relays and automatic disconnect switchgear that may be installed, this equipment may not always function properly and the cogenerator could damage the utility's equipment or other customers' appliances. Under PURPA, the net increased interconnection costs may include the cost of insurance against liability for such damage, or liability may be assigned to the cogenerator in the purchase power contract. Liability issues also have been raised regarding wheeling, but in that case no special insurance policy is needed, and all the ratepayers share any liability for damage due to wheeled power (6).

At the present time, few guidelines exist for utilities concerning the liability of the cogenerator. A set of guidelines being prepared by EPRI recommends that the cogenerator be responsible for damages caused by the cogeneration system, up to and including the connection to the customer's side of the meter (20). A second approach has been adopted by Southern California Edison, whose interconnection contract provides that:

> Customer is solely responsible for providing protection for customer's facilities operating in parallel with Edison's system and shall release Edison from any liability for damages or injury to customer's facilities arising out of such parallel operation, unless caused solely by Edison's negligence . . . Customers shall be required to maintain an in-force liability insurance in an amount sufficient to satisfy reasonably forseeable indemnity obligations and shall name Edison as an additional insured under said insurance policy (49).

A precise definition of "reasonably foreseeable indemnity obligations" is not yet clear. Few utilities will put an exact figure in writing and leave each case to be determined on an individual basis. Many have argued against some of these liability requirements that place an excessive cost burden on owners of cogenerators and small power producers. A staff report to the California Public Utilities Commission (CPUC) recommended that utilities be allowed to include only standard "boilerplate" liability and indemnity provisions, and not to require a cogenerator "to assume a greater responsibility for losses resulting from its acts or equipment failure than it would have under common law principles" (8). The staff also has tried to eliminate the dual cost burden of insurance and dedicated transformers, and has recommended that cogenerators and small power producers with capacity under 20 kW that have installed dedicated transformers be excused from providing proof of liability insurance. In another case, the New York Public Service Commission ruled that the utility could not require a cogenerator to assume the utility's broadly sweeping liability clauses, but rather the utility could require a cogenerator to be responsible only for negligent installation and operation of his equipment (3).

Summary of Requirements

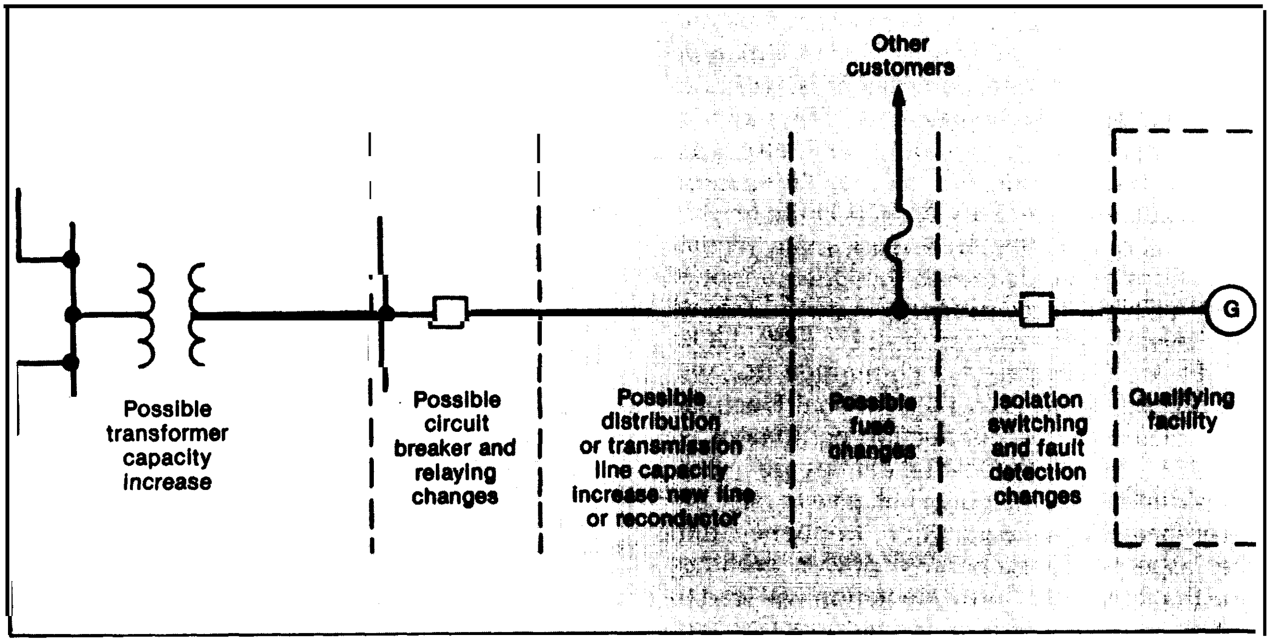
Cogenerators may need several types of equipment for proper interconnection with centralized utility grids: corrective capacitors to meet power factor requirements, relays and filters to protect the circuits of other customers, special meters to measure cogeneration energy profiles, and dedicated transformers and increased transmission and distribution line capacity to ensure reliable service. Moreover, cogenerators may be required to carry special liability insurance to limit the responsibility of the utility or its noncogenerating customers. These requirements are displayed graphically in figure 41.

While utilities and cogenerators agree that interconnection may pose all of the problems discussed above, there is still much to be decided about the frequency and severity of these problems for particular cogeneration systems. Even when utilities and cogenerators agree about the nature of potential interconnection problems, they may disagree about the type or quality of equipment necessary to resolve them.

Quality of Interconnection Equipment

One of the critical questions concerns the quality of the equipment used in the interconnection. There are two basic levels of quality: "industrial"

Figure 41.—Possible Power System Additional Equipment Requirements to Serve Qualifying Facilities



SOURCE: Blair A. Ross, "Cogeneration and Small Power Production Facility Effects on the Electric Power System," paper presented at Federal Energy Regulatory Commission conference on Cogeneration and SmalL Power Production RuLes, June 1980.

and "utility" grades. Utility grade equipment generally is more reliable and responsive, but it also costs more than industrial grade (40). Although requirements have varied in the past, a general consensus is emerging that industrial grade equipment is adequate for smaller (under 300 kW) cogenerators while larger cogenerators should use the more costly utility grade. This distinction is based not only on the safety implications of a system failure but also on the cost of replacing damaged equipment. For smaller cogeneration systems, the maintenance or replacement cost of utility grade equipment could be several times higher than the cogenerator's monthly electricity bill.

However, utility grade equipment may be necessary under certain circumstances. For example, Southern California Edison requires "utility quality" protective relays if a cogenerator is large enough (more than 1 -MW installed capacity) that the opening and closing of utility relays must be synchronized (49). While many utility engineers agree with this distinction, they also may disagree about the size of equipment that requires industrial or utility grade. One source suggests that industrial grade equipment should be used by cogenerators smaller than 200 kW, while others suggest 1 MW as the cutoff point (34).

Guidelines for Interconnection

Utilities differ widely in their general specification of interconnection requirements. Some utilities have adopted guidelines, while others review each interconnection design to ensure that it meets their standards. Although case-by-case review can result in costly delays for a cogenerator, utilities and interconnection experts agree that separate reviews are necessary until industrywide standards have been developed for the interconnection of onsite generating equipment (4). At this time, each cogenerator has virtually custom-designed configurations of interconnection equipment because the circumstances under which connections are made vary widely, and so few cogenerators have been installed by each engineer that it is difficult to generalize and use rules-of-thumb (57).

Research is underway to provide the needed information for future guidelines, and several subcommittees of the Institute of Electrical and Electronics Engineers' (IEEE) Power System Relaying Committee* are working together on a manual of accepted interconnection standards, with specific engineering guidelines for a wide range of equipment types and conditions. EPRI also is assembling its own guidelines, although for a more general audience, and researchers at the Jet Propulsion Laboratory (JPL) have made many recommendations on guidelines to the Department of Energy's (DOE) Electrical Energy Systems Division (25). Several staff members at IEEE, EPRI, DOE, and JPL are delegates to a committee that will recommend changes in the National Electrical Code related to interconnection equipment by late 1983 (24). Finally, several utilities are installing instruments on their own initiative to measure power factor, voltage variation, frequency, and other aspects of cogenerated power, with the hope that this better instrumentation will lead to a better understanding of interconnection performance, costs, and benefits (37).

This research points out the need for performance-based guidelines—allowing cogenerators to meet general functional criteria—rather than technology-specific guidelines that might require particular technologies that could become outmoded or more costly in the future. The CPUC staff (8) recommended that utilities should use performance-based guidelines (that specify such functions as reacting properly to utility system outages, assisting the utility in maintaining system integrity and reliability, protecting the safety of the public and of utility personnel), rather than specifying a list of equipment that could restrict cogeneration unnecessarily (8).

Southern California Edison complied with the CPUC staff recommendation by issuing a complete set of equipment performance specifications as its guidelines. The guidelines provide all requirements for design, installation, and operation of interconnecting equipment in clear, easy-to-read language, and include examples of wiring diagrams and metering configurations that meet its performance specifications for three types of cogenerators: those over 200 kW with the interconnection equipment owned by the customer, those over 200 kW with the equipment owned by the utility, and those under 200 kW (49). Other consultants have also suggested that different policies be used with different sizes of generators, with one policy covering units under 5 kW, another for units between 5 and 40 kW, and a third for units over 40 kW (40).

Southern California Edison requires all interconnection equipment (that eventually will be owned by the utility) for cogenerators larger than 200 kW to have four functions:

(i) A set of utility-owned circuit breakers in addition to any circuit breakers that the customer may have installed,
(ii) synchronizing relays,
(iii) meters for kW and kWh produced and demanded, kVARh demanded, and (for cogenerators larger than 1 MW) telemetry and telephone communication lines, and
(iv) protective relays for short circuits, isolation (to separate the cogenerator from other customers on its line), over/under frequency and voltage, and circuit-breaker closing/reclosing (to prevent the re-energizing of an open line) (49).

For installations over 200 kw with customer-owned interconnections, the Southern California Edison requirements state: "The customer shall provide adequate protective devices to detect and clear . . . short circuits, . . . detect voltage and frequency changes, . . . and prevent reparalleling the customer['s] generation." There are similar, although less stringent, requirements for under 200 kW equipment (49).

Southern California Edison also gives the cogenerators three different options for paying for all required interconnection equipment: (i) the utility supplies and owns the interconnection equipment and the cogenerator pays a standard monthly charge, currently 1.7 percent of the total costs of the facilities; (ii) the cogenerator installs the equipment to utility specifications and transfers ownership to the utility at which time the utility assesses a one-time engineering charge for approving the design, and the utility charges monthly operation and maintenance fees for the equipment (currently 0.75 percent of the total costs of the facilities), or (iii) the utility builds the equipment, with an advance payment from the cogen-

*Hassan and Klein (25) give a good list of the various groups within IEEE, as well as other organizations, that are working on these issues.

erator, and the cogenerator pays the monthly operation and maintenance charge once construction is completed (49). Most utilities just offer the last option, with monthly charges greater than $1,000 for large installations of several megawatts capacity, and much less for smaller facilities **(46).**

Costs for Interconnection

Interconnection costs can vary widely depending on the size of the cogeneration system and on the requirements of the utility or State regulatory commission. Two published studies on cogeneration allow for a detailed comparison of costs for a variety of assumptions. One set of sample costs includes schemes for a variety of generators and is shown in table 26. These schemes have used similar assumptions in assembling the interconnection costs, and so are useful for comparison purposes and relating the economies of scale of interconnection.

As can be seen in table 26, the interconnection requirements for the larger units cost less per kilowatt to construct and maintain; and as the size of the cogenerator decreases, the cost per kilowatt increases rapidly, from $35/kW for the 20-MW generator up to $1,328/kW for the 2-kw generator. Because cogenerators in this range typically cost about $1 ,000/kW, the total costs for interconnection of these smaller generators can exceed the capital costs of the generators.

Some utility personnel feel these costs are higher than their experience would indicate (35,43). Some of these costs may be unnecessary or else might be paid by the utility instead of by the cogenerator (6,8). For instance, dedicated transformers may be installed already, thereby reducing the total interconnection cost substantially—in some cases by more than 30 percent.

These costs also depend heavily on whether existing switchgear is adequate or whether modifications will be necessary to accommodate the cogeneration equipment. For example, two different 900-kW installations might vary in cost between $150,000 (or $167/kW) and $250,000 (or $278/kW)–with the difference resulting from the number of modifications needed in existing distribution cables and switchgear (57).

Based on the published information, OTA has assembled cost information for three different sized systems, using two series of assumptions for interconnection requirements for two of the smaller generators and one set of assumptions for the larger generator (22).

Table 26.—Cogeneration Interconnection Sample Costs[a]

Scheme[b]	Equipment (kW) Generator size	Transformer size	Costs (dollars) Switchgear	Transformer	Relay	Engineering labor	Total	Total cost ($/kW)
Larger generators:								
A	20,000	20,000	$296,000	$314,000	$51,000	$30,000	$691,000	$35
B	5,000	10,000	150,000	160,000	43,000	30,000	339,000	68
C	4,200	10,000	129,000	160,000	18,000	26,000	319,000	76
D	1,000	2,500	56,000	31,000	11,000	12,000	104,000	104
E	200	750	27,000	16,000	7,000	10,000	60,000	300
Smaller generators:								
F	100	111	$4,700	$2,250	$2,065	$1,900	$10,915	$109
G'	50	112	4,340	1,530	2,125	1,550	9,545	191
H	50	112	1,570	1,530	1,325	1,500	5,925	119
I	20	30	2,590	640	360	1,450	5,040	252
J[d e]	5	25	496	130	360	950	1,935	387
K[d]	2	10	1,035	350	320	950	2,655	1,328

aAll costs include new (either shared or dedicated) transformers, but do *not* include: watthour meters, annual maintenance requirements for all interconnection equipment, and site preparation and cabling costs,
b industrial-grade relays are used in all schemes.
cScheme G uses more expensive circuit breakers than the other small generator schemes.
dschemes A *through I use synchronous* generators, all others use induction generators..
escheme J uses a shared transformer, all others use dedicated ones.

SOURCES: Office of Technology Assessment, from James Patton, Survey of *Uti/ity Cogeneraflon hterconnection Practices and Cost—Flna/ Report* (Washington, D. C.: U.S. Department of Energy, DOE/RA/29349-OI, June 1980); James Patton and S. Iqbal, Small *Power Producer Irrterconnectlon Issues and Costs* (Argonne, Ill.: Argonne National Latmratory, February 1981).

Because the range of conditions and the use and cost of interconnection equipment may vary widely with smaller cogenerators, two sets of assumptions were used; a "best case" that assumes that power factor correcting capacitors, a dedicated transformer, and protective relays would not be needed; and a "worst case" that assumes that this equipment (along with more expensive meters and equipment transformers for these meters and relays) would be needed. Both 50-kW systems use induction generators, while both 5oo-kW and 5-MW systems use synchronous generators.

All of the equipment meets industrial grade specifications and operates at 480 volts on a three-phase circuit (these are common conditions for medium-sized equipment). All of the costs cited include installation, except for the protective relays which cost $250 to install (22). Table 27 displays the various cost components of the interconnection for the three generators.

The cost to interconnect the smallest generator (50 kW) varies between $52 and $260/kW, or a range of 5 to 26 percent of the capital cost of the generator (assuming $1 ,000/kW capital cost). The cost for the 500-kW generator varies between $22 and $66/kW, or 2 to 7 percent of the capital cost, while the cost for the largest generator (5 MW) is $12/kW, or 1 percent of the capital cost.

From table 27, two important results are observed: First, most of the variations in cost result from the addition of a dedicated transformer to the interconnection requirements, as well as the use of more expensive relays and other protective devices. Second, the cost per kilowatt of capacity decreases quickly as the size of the generator increases, primarily due to the economies of scale for circuit breakers, transformers, and installation costs, and because most of the cost of the relays is independent of the size of the generator they protect. For example, even though the capacity of the !@O-kW generator is ten times that of the 50 kw, the circuit breaker costs only eight times as much and the dedicated transformer only three times as much.

From these studies, it is concluded that there is a great deal of variation in the cost of interconnection equipment per kilowatt of cogeneration capacity. The costs will depend on the size of the cogenerator and the amount of transmission and distribution equipment already in place. Costs per kilowatt will increase as the size of the generator decreases and as the amount of new transmission and distribution equipment increases.

Summary

Interconnecting cogeneration could create problems for utilities, especially with respect to providing satisfactory power quality, controlling system operation, and minimizing utility liability and safety problems. While many of these problems may require special dedicated facilities or

Table 27.—interconnection Costs for Three Typical Systems

Equipment	50 kW		500 kW		5MW
	Best	Worst	Best	Worst	Average
Capacitors for power factor	—	$1,000		$5,000	– “
Voltage/frequency relays	$1,000	1,000	$1,000	1,000	$1,000
Dedicated transformer	—	3,900	–	12,500	40,000
Meter	80	1,000	80	1,000	1,000
Ground fault overvoltage relay	600	600	600	600	600
Manual disconnect switch	300	300	1,400	1,400	3,000
Circuit breakers	620	620	4,200	4,200	5,000
Automatic synchronizers	—	—	2,600	2,600	2,600
Equipment transformers	600	1,100	600	1,100	1,100
Other protective relays	—	3,500	–	3,500	3,500
Total costs ($)	$2,600	$13,020	$11,080	$32,900	$57,800
Total costs ($/kW)	52	260	22	66	12

NOTE: "-" means an optional piece of Interconnection equipment that was not Included in the requirements and cost calculations.

SOURCE: Off Ice of Technology Assessment calculations based on data derived from Howard S. Geller, The *Interconnection of Cogenerators arrd Small Power Producers to a Utility System* (Washington, D. C.: Office of the People's Counsel, February 1982), operating and administrative techniques, none are insurmountable and most have been resolved in the past (44). One executive remarks that the utility industry has not yet identified any problems with distributed generation which cannot be solved technically (43). The real problem is whether the cost involved will be prohibitive.

However, in order to determine costs, more analysis and better data are needed. Results obtained to date through simulation and analysis must be verified in the field (25). In addition, State commissions need to encourage those utilities that have not yet done so to prepare guidelines for interconnection requirements, and to update those guidelines as the results of new research being conducted by EPRI, DOE, APPA, IEEE, and individual utilities are made available, and as experience is gained.

THERMAL AND ELECTRIC STORAGE

The analysis in chapter 5 shows that the greatest opportunity for cogeneration occurs when onsite thermal demands closely match regional electric demands. To some extent, a cogenerator or a utility could mitigate a mismatch between these two demand curves through the use of devices that store either the thermal or electrical energy for release when it is needed. Thermal and electric storage techniques are described briefly below. *

Thermal Storage

The thermal demand of an industry or building is rarely constant; rather, it varies with the day (e.g., weekday v. weekend day) and time of day as well as with the season. As a result, an industrial or commercial cogenerator may produce more thermal energy than can be used immediately onsite. Similarly, if a cogenerator is supplying electricity to the utility grid, a mismatch between the timing and/or magnitude of the onsite thermal needs and the utility's electric demands could result in temporary excess thermal energy production. In such circumstances, it maybe advantageous to store this excess thermal energy for subsequent use during periods when the cogenerator is producing less than is needed onsite. Thermal energy storage also can be used to reduce peakloads on utility powerplants, to improve the efficiency of heating or cooling devices by reducing cyclic losses, and to make it practical to utilize periodic renewable energy sources (e.g., excess solar energy collected during the day can be stored for heating during the night).

There are three basic approaches for storing thermal energy. In sensible-heat storage, engine or exhaust heat is used to elevate the temperature of a liquid or solid that does not melt or otherwise change state for the temperature range in question. Water is the most widely used material for sensible-heat storage. It is relatively easy and inexpensive to store at temperatures below its boiling point, but can be stored at temperatures up to 300° to 400° F if pressurized tanks are used. At higher temperatures, the pressure required to maintain water in its liquid form would greatly increase the cost and danger of operating the system. Even at lower temperatures, it can be difficult to maintain constant output temperatures when the stored energy is tapped. Rocks also can be used in sensible-heat storage by heating them and keeping them in insulated containers. However, the heat storage capabilities of rocks are poorer than those of water,

Latent-heat storage occurs when a material undergoes a phase change (e.g., melting, vaporizing) when heated. This approach supplies energy at a relatively constant temperature and usually allows for greater amounts of energy to be stored in a given volume or weight of material, as compared to the sensible heat approach. More than 500 phase change materials have been reported as potential thermal energy storage candidates, but three basic categories are used in low-temperature applications: 1) inorganic salt compounds, 2) complex organic chemicals such as paraffins, and 3) solutions of salts and acids. The

*More detailed information on both types of storage maybe found [n reference 38.

disadvantages of latent-heat storage include the high cost of the phase change materials and the difficulty involved with transmitting thermal energy in and out of the storage medium.

Chemical storage techniques use heat to produce a chemical reaction, and then release the heat when the reaction reverses. The most promising materials for the chemical storage of thermal energy are metal hydrides (compounds of the metal and hydrogen) because their reactions can be reversed easily. Moreover, hydrides have relatively high heats of formation, while the reaction products can be stored at ambient temperatures and the heat recovered as needed and stored indefinitely with no need for insulation. Chemical storage techniques may be applied at a wide variety of temperatures, and transporting the chemical energy is convenient. However, chemical storage is likely to be less attractive than other methods because the catalysts required to facilitate the chemical reaction are expensive, as is the storage of gaseous chemicals in pressurized tanks, and the metal hydrides may be highly toxic and pose a dangerous fire risk.

The size of a thermal storage unit will depend on the onsite energy needs (e.g., a single residence, a large building or industrial plant, a utility powerplant). However, most of the experience to date is in the design, construction, and operation of smaller thermal energy storage systems capable of storing heat from electric generating plants with less than 500-kW capacity. Table 28 indicates possible required storage capacity as a function of typical industrial plant sizes.

Reliable data on costs, maintenance, and performance for thermal energy storage systems are not yet available. **Most systems are still in R&D stages.** Thermal energy storage using water in above ground or underground tanks has been studied the most and is closest to being ready for commercial use, although even these systems require more research and design work.

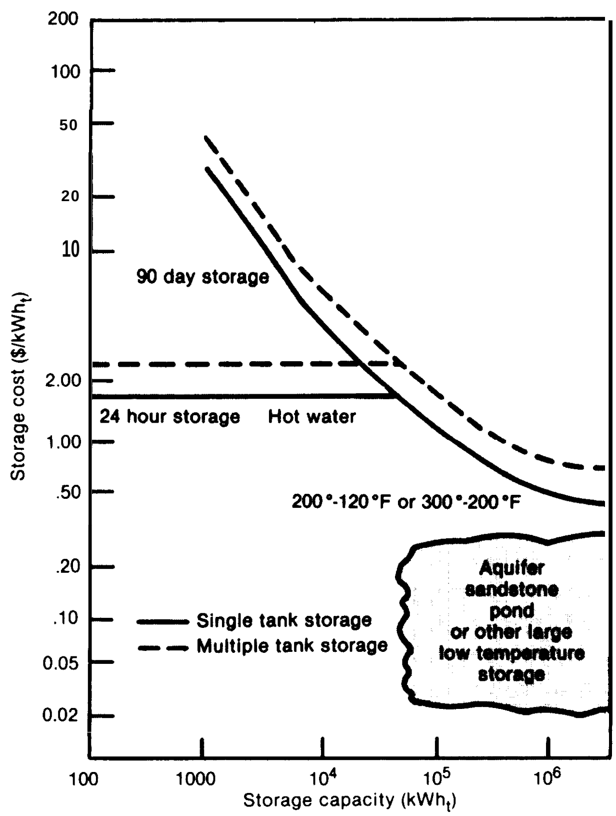
The component costs of a thermal energy storage system will include the cost of the storage medium itself, the containment facility that houses the medium, and the maintenance required to keep the storage system in working order. Other costs that accrue to sensible-heat systems using water include the cost of additives to inhibit corrosion or prevent freezing, which can be significant. Although costs are uncertain, developers have estimated storage costs as a function of storage capacity for several low- and high-temperature thermal storage systems (see figs. 42 and 43).

Table 28.–Thermal Energy Storage (TES) Capacity Range v. Plant Size

Characteristic size (MW)	TES capacity range (10^7 Btu)
2	4 to 6
20	40 to 60
100	200 to 300

SOURCE: Roger L. Cole, et al,, *Oesign and Installation Manual for Thermal Energy Storage* (Argonne, Ill.: Argonne National Laboratory, AN L-79-15, 2d cd., January 1960)

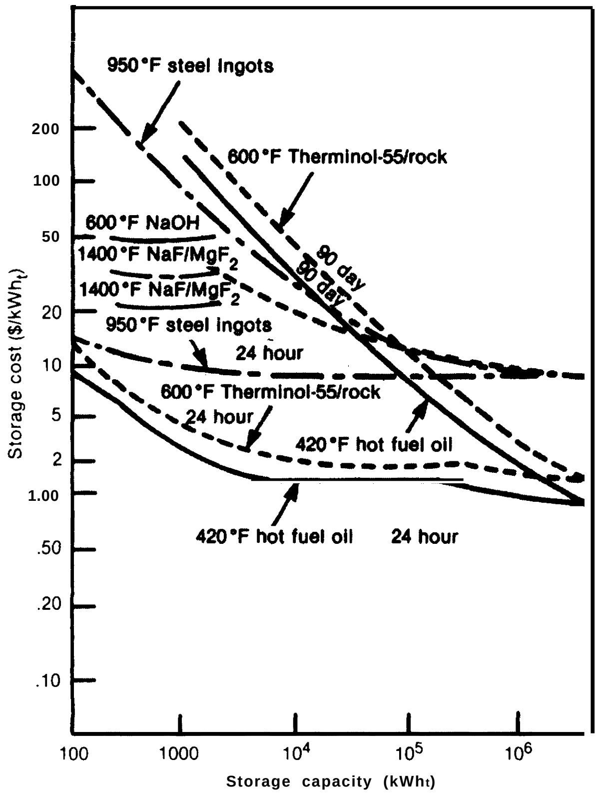
Figure 42.— Low-Temperature Thermal Storage Cost per KWh_t v. Storage Capacity



NOTE: The storage units would lose only about 5 percent of the energy stored in the interval indicated. This cost is based on precast concrete and coated steel, and excludes 25 percent O&P.

SOURCE: *Application of Solar Technology to Today's Energy Needs, Volumes I and II* (Washington, DC.: U.S. Congress, Office of Technology Assessment, 1976).

Figure 43.—High.Temperature Thermal Storage Cost per kWh$_t$ v. Storage Capacity



NOTE The storage units would lose only about 5 percent of the energy stored in the interval indicated

SOURCE. Appl/cat/on of Solar Techrrology to *Today's Energy Needs, Volumes 1 and //* (Washington, D C.: U.S Congress, Office of Technology Assessment, 1978)

Some general factors affecting efficiency, or the **percentage of thermal energy recovered from storage, are the supply temperature range (the ratio of the input temperature to the storage material temperature), the specific heat of the storage medium, and the insulating properties of the storage container. In general, the overall efficiency (energy in/energy out) declines as the input temperature increases.**

Little special maintenance **should be required for thermal storage tanks because they contain no moving parts.** However, it is necessary to check the tanks periodically for corrosion, and the effects of normal weathering may necessitate repainting or repair of the tank,

Electric Storage

Storage of electricity is an alternative means of matching generating capacity output with user demand. **It may** be particularly advantageous in conjunction with intermittent sources of electricity, including wind and solar generators as well as some cogenerators.

The primary methods of storing electric energy are:

- ***pumped storage,*** in which electricity is used to pump water to a higher elevation during periods of low electricity demand, and then the water is released to the lower elevation to drive a turbine during times of peak demand;
- ***compressed air storage,*** in which electricity is used to compress air during low demand periods, and then the air is heated and expanded through a combustion turbine to generate electricity at peak demand;
- ***electrochemical storage,*** which (as with chemical thermal energy storage) uses reversible electrochemical reactions to store electric energy (e.g., in batteries);
- ***mechanical energy storage,*** which uses flywheels brought up to speed by electric motors to store kinetic energy for subsequent controlled release to generate electricity; and
- ***thermal storage,*** in which electricity is converted to heat and stored in hot solid, liquid, or gaseous materials (as described above) for subsequent controlled release to generate elect ricity.

The most common form of electric energy storage for dispersed energy systems (such as cogenerators) would be battery storage. * However, the electric energy must be introduced and withdrawn from batteries as direct current, and thus inverters must be included in any battery system that receives and produces alternating current. Within large bounds, the cost of batteries per unit of storage capacity is independent of the **size of** the system because most batteries consist of a

*Battery storage of electricity is discussed in detail In ***increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports*** (OTA-E-185, September 1982).

large number of individual reacting cells. Larger systems may benefit from some economies of scale because of savings due to more efficient packing, lower building costs, and possibly lower costs of power conditioning (see discussion of interconnection), but a separate analysis on this point must be performed for each type of battery. It is likely that there will bean optimum size for each device.

Lead-acid batteries are the only devices currently mass produced for storing large amounts of electric energy using electrochemical reactions. Systems as large as 5,000 kWh currently are used in diesel submarines. However, contemporary lead-acid battery designs have a relatively low storage capacity per unit weight (due largely to the amount of lead used), and batteries now on the market that can be discharged deeply often enough for onsite or utility storage applications are too expensive for economic use in electricity generation. Extensive work is being done to determine whether it is possible to develop batteries suitable for use in utility systems, including work on advanced lead-acid battery designs and on several types of advanced batteries that may be less expensive than lead-acid batteries in the long term.

Advanced battery types include nickel-iron, nickel-zinc, zinc-chlorine, sodium-sulfur, and lithium-metal sulfides. Operating and cost characteristics as well as expected availability data are given in table 29 for several battery types. A comparison of technical and cost characteristics for several electric storage systems, including thermally based electric storage is given in table 30.

Table 29.-Cost and Performance Characteristics of Advanced Batteries

Battery type	Operating temperature (degrees Celsius)	Energy density (watthours per kilogram)	Power density (watts per kilogram)	Estimated cycle life	Estimated cost (dollars per kilowatthour)	Estimated availability (year) (prototypes or early commercial models)
Lead-acid						
Utility design	Ambient	—	—	2,000	80	1984
Vehicle design (improved).	Ambient	40	70	> 1 ,000”	70	1982
Nickel-iron	Ambient	55	100	>2,000 (?)	100	1983
Nickel-zinc	Ambient	75	120	800 (?)	100	1982
Zinc-chlorine						
Utility design	30-50	—		2,000 (?)	50	1984
Vehicle design	30-50	90	90	> 1,000 (?)	75	1985
Sodium-suifur						
Utility design	300-350	—	—	> 2,000	50	1986
Vehicle design	300-350	90	100	> 1,000		1985
Lithium-iron sulfide. . .	400-450	100	>100	1,000 (?)	80	1985

NOTE: Variety of advanced types of batteries are currently under development for electric-utlllty storage systems and electric vehicles because the lead-acid battery probably cannot be Improved much further. The table lists the properties of batteries that may prove superior. The most important criterion for storage in electric-power systems is long life: the ability to undergo from 2,000 to 3,000 cycles of charge and discharge over a 10- to 15-year period. For electric vehicles the chief criteria are high energy content and high power for a given weight and volume. (The dashes indicate that these criteria do not apply to electric utilities.) Both the utillties and vehicles wIll require batteries that are low in cost (preferably less than $50/kWh of storage capacity), safe, and efficient.

SOURCE: F. R. Kalhammer, “Energy-Storage Systems,” 241 *Scientific American 5665,* December 1979.

Table 30.—Expected Technical and Cost Characteristics of Selected Electrical Energy Storage Systems

Characteristics	Hydro pumped storage	Compressed air	Thermal: Steam	Thermal: Oil	Lead-acid batteries	Advanced batteries
Commercial availability . . .	Present	Present	Before 1985	Before 1985	Before 1985	1985-2000
Economic plant size (MWh or MW)	200-2,000 MW	200-2,000 MW	50-200 MW	50-200 Mw	20-50 MWh	20-50 MWh
Power related costs[a] ($/kW)	90-160	100-210	150-250	152-250	70-80	60-70
Storage related costs[a] ($/kWh)	2-12	4-30	30-70	10-15	65-110	20-60
Expected life (years)	50	20-25	25-30	25-30	5-10	10-20
Efficiency[b] (percent)	70-75	—c	65-75	65-75	60-75	70-80
Construction leadtime (years)	8-12	3-12	5-12[d]	5-12[d]	2-3	2-3

aConstant 1975 dollars, does not include cost of money during construction.
bElectric energy out to electric energy in, In percent
cHeat rate of 4,200 t. 5,5oo Btu/kWh and compressed air pumping requirements from 0.58-0.80 kwh (out)
dLong leadtime includes construction of main PowerPlant.

SOURCE' Decision Focus, Inc., *Integrated Analysis of Load Shapes and Energy Storage* (Palo Alto, Calif.: Electric Power Research Institute, EPRI EA-970, March 1979)

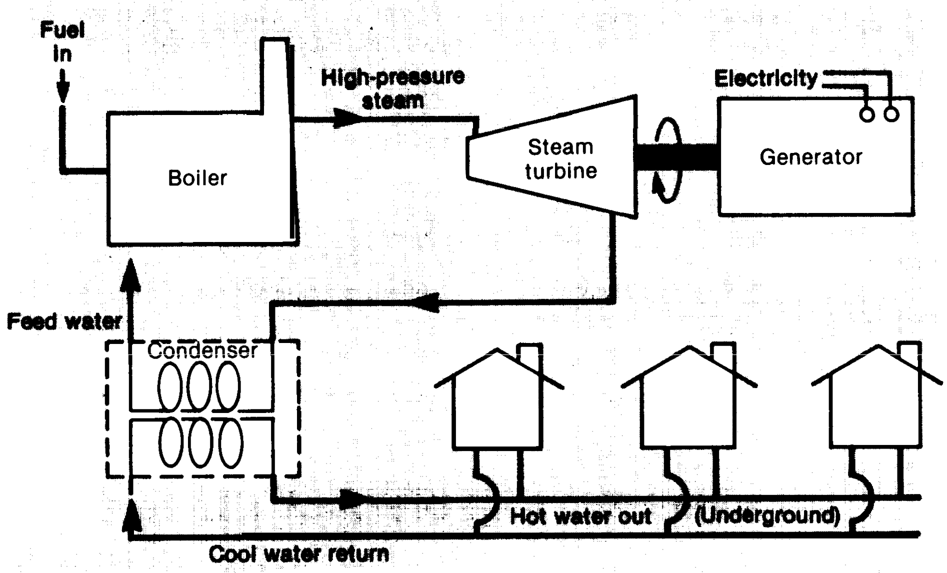
COGENERATION AND DISTRICT HEATING

District heating is the use of one or more centralized sources of heat to supply thermal energy to a group of buildings through a piping network. A district heating system could provide space heating and domestic water heating, and in some cases space cooling, to residential and commercial customers, or it could provide thermal energy for industrial processes. A district heating system is not limited to any particular type of heat source, but could use conventional boilers, cogenerators, industrial or utility waste heat, or municipal incinerators with heat recovery equipment. District heating systems generally are thought of as large citywide systems—and thus, in a sense, centralized power production—but they also can be smaller systems suitable for industrial or commercial parks, college campuses, and military bases. This section will summarize the advantages and disadvantages of district heating based on cogenerators; a more complete discussion of district heating can be found in the OTA assessment, The ***Envgy Efficiency of Buildings in Cities.***

A district heating system comprises three major components, as shown in figure 44: the thermal production plants that provide heat to the system; the underground transmission/distribution system, which conveys thermal energy (in the form of hot water or steam) from the thermal production plants to customers; and the in-building equipment—typically a heat exchanger that forms the connection between the system distribution network and the remainder of each in-building heating and cooling system.

Proponents of district heating systems for the United States cite several potential advantages of such systems, including the improved fuel utilization efficiency of cogeneration compared to conventional steam-electric generating stations (as described above); reduced heating costs (through the use of currently discarded heat and increased equipment efficiency) relative to conventional heating systems; increased certainty of fuel supply, through reduced consumption of oil and

Figure 44.—European Cogeneration District Heating System



SOURCE: Bruce W. Wilkinson and Richard W. Barnes (eds.), Cogeneration *of Electricity and Useful Heat* (Boca Raton, Fla.: CRC Press, Inc., 1980).

natural gas for space heating, and/or a switch to coal or waste fuels; reduced fire hazards in buildings, through the substitution of a heat exchanger for a furnace, a boiler, or electric resistance heaters; reduced land requirements for sanitary landfills if resource recovery facilities, such as heat recovery incinerators, are used in district heating systems; and increased employment and revitalization of urban areas.

However, district heating also may have a number of disadvantages. These include a very high capital cost, due mainly to the transmission/distribution piping. Financing is crucial to the economic viability of district heating systems. If the district heating system burns a high-grade fossil fuel (natural gas or oil), the increase in fuel use efficiency and the cost advantage to the consumer (compared to individual heating units) are diminished by the high capital costs and thermal losses in piping. Thus, a district heating system will have a clear benefit only if it can utilize lower price, relatively abundant fuels such as coal and municipal solid waste that cannot be burned directly in individual heating units. In addition, the installation and maintenance of district heating systems, including the time required for the piping, can be drawn out and disruptive. During construction, commercial establishments may lose business and traffic may have to be rerouted. Furthermore, system maintenance sometimes will require reexcavation of the pipes, but cannot always be performed during periods of low heat demand (summer), since a break in the system during the winter could prevent heat from reaching customers who do not have backup heating systems. Finally, district heating systems have limited applicability, and some very specific conditions must be met for viability, including a high connection rate and careful design and siting. These latter points are discussed more completely in *The Energy Efficiency of Buildings in Cities.*

District heating is not a new idea, but a technically proven concept with no breakthroughs or discoveries needed for implementation. Over 40 utility-run steam district heating systems in the United States go back as many as 80 years, while many smaller steam systems serve university campuses, shopping centers, industrial parks, military bases, or industrial plants located adjacent to power stations. A high proportion of the heat in

Northern Europe is supplied by hot water district heating. However, U.S. city-scale district heating systems owned by utilities have, up until now, enjoyed little success when compared to European systems, primarily because European systems use hot water instead of steam. Steam district heating systems are only justified for small areas with very high thermal load densities, preferably with connections to industrial users. Hot water systems are preferred for commercial/residential space and water heating because thermal extraction from steam turbine cogenerators (the most common type used in district heating systems) should be done at relatively low temperatures to reduce losses in electric generating capacity (see discussion of steam turbine efficiency, above) and heat losses during transmission and distribution.

The potential contribution of cogeneration district heating could be significant, but its actual use will be strongly influenced by a variety of technical, institutional, and economic factors. Its feasibility is extremely site- and region-specific. Such factors as climate, energy density, fuel type, fuel availability, present and future fuel cost, age and type of heating equipment in existing buildings, and type of existing electric generating capacity can influence the viability of district heating. In addition, analyses of district heating systems are extremely sensitive to interest rates, tax provisions, utility rate structures, environmental regulations, local building and electrical codes, and labor regulations. Promotion of district heating may require streamlining of permit procedures, additional tax credits, low cost loans, resolution of conflicts with environmental regulations, and favorable treatment with respect to fuel allocations and curtailments.

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