CHAPTER 9

INTRODUCTION TO PART IV

Most studies emphasize the potential role of methanol as an alternate fuel for the transportation sector. However, there is increasing technical evidence that methanol may also be an excellent fuel for the generation of electricity, especially in technologies such as gas turbines and to a lesser extent boiler-fired steam turbines that are now designed for oil or natural gas. Limited test burns in these technologies have shown that, with minor equipment modifications, methanol can perform on a par with oil or natural gas in combustion efficiency and power production capabilities. In addition, methanol's environmental performance is considered to be superior to these fuels as well as to coal, now the primary fuel used by utilities. It emits no sulfur dioxide, no particulate matter, and lower levels of nitrogen oxides than these other fuels; aldehyde emissions may, however, prove to be a problem.

Early indications, therefore, are that methanol may prove to be a clean-burning and efficient fuel for utility use, and that its penetration into the utility market depends less on questions about its technical and environmental performance, than on its economic competitiveness with traditional and new utility fuels in the future mix of generating technologies.

The purpose of Part IV is to examine these factors in greater detail. Chapter 10 will look more closely at the physical properties of methanol when used in utility technologies now designed for fossil-fuels. Its technical and environmental performance in boilers, gas turbines, and combined-cycle units (a combination of the two) will be examined.

Chapter 11 will quantify the competitive edge of methanol, if any, over other utility fuel choices during the 1990-2010 forecast period. Chapter 12 will look at the market prospects of methanol.

The remainder of this chapter discusses three background topics: fuels now used in electric utilities; utility technologies suitable for methanol use; and the effect of equipment utilization rates (load factors) on fuel choice.

FUELS NOW USED IN UTILITIES

Electricity now accounts for about 30 percent of all the energy consumed in this country. It is used primarily for lighting, space heating, cooling, and driving small electric motors in residential, commercial and industrial end-use markets. Electricity demand is expected to grow at annualized rates of from two to four percent per year through the year 2000. Electricity is considered a secondary energy form in that other primary energy resources must undergo conversion to produce it. The major fuels used today are fossil-fuels, hydro power and nuclear energy.

In current fossil-fueled utility technology, electrical energy is produced from the conversion of thermal energy obtained from fossil-fuel combustion to the mechanical energy required to drive a turbine and generator. In 1979 about 76 percent of all electricity came from the combustion of either coal, oil or natural gas. Of these, coal was by far the dominant source (46 percent), with oil and natural gas sharing almost equally the remaining 30 percent.

Hydro power is another important source for electricity production. Here the kinetic energy in falling water is converted to the mechanical energy needed to produce the electrical current. Hydroelectric power was once the dominant form of electricity in the early years of the utility industry, but has declined in importance as the number of suitable water sites has not increased. Today, hydro power accounts for about 13 percent of total electricity production.

Electricity from nuclear power is also a large part of today's production mix. Like fossil fuels it produces electricity from the conversion of thermal energy to mechanical energy to drive a turbine and generator. However, the thermal energy is derived from a nuclear reaction rather than from combustion of chemical fuels. Nuclear power accounts for about 11 percent of total electricity production today. Its share is expected to increase through the year 2000, but the magnitude of the increase is highly uncertain given current reevaluation of the safety of nuclear powerplants.

Finally, a small fraction of current electricity production results from the conversion of renewable energy forms. These include geothermal, wind, and biomass fuels.

UTILITY TECHNOLOGIES SUITABLE FOR METHANOL USE

The purpose of this section is to describe briefly the operation of three conventional utility technologies: boiler-fired steam turbines, gas turbines and combined-cycle units for generating electricity. These are considered the most likely units in which methanol could successfully be burned.

Boiler-Fired Steam Turbine

Most conventional steam turbine powerplants are a configuration of four basic components: a boiler, a steam turbine, a generator, and a cooling system.[1/] For environmental reasons, steam plants fired with coal and dirtier oils are increasingly adding a fifth component to the process: stack gas clean-up equipment. Steam powerplants comprise the bulk of capacity now used to generate electricity. (See Figure 9-1.)

In simplified terms, a conventional steam turbine powerplant produces electricity in three stages, each of which utilizes one of the components listed above: first, the chemical energy in a fossil-fuel, such as coal, oil or gas, is converted to thermal energy through combustion in the boiler. This heat energy is then transferred from the boiler to circulating liquid water to produce high pressure, high temperature steam of up to 1000 F. The heat energy in the steam is then converted to mechanical energy in the second stage of the process, when the steam enters the turbine, expands, and thereby turns the turbine blades. In the final stage, the mechanical energy of the spinning turbine drives the generator, where a magnetic field is created and is converted to electrical energy. This electricity is then fed to consumers through a network of transmission and distribution lines.

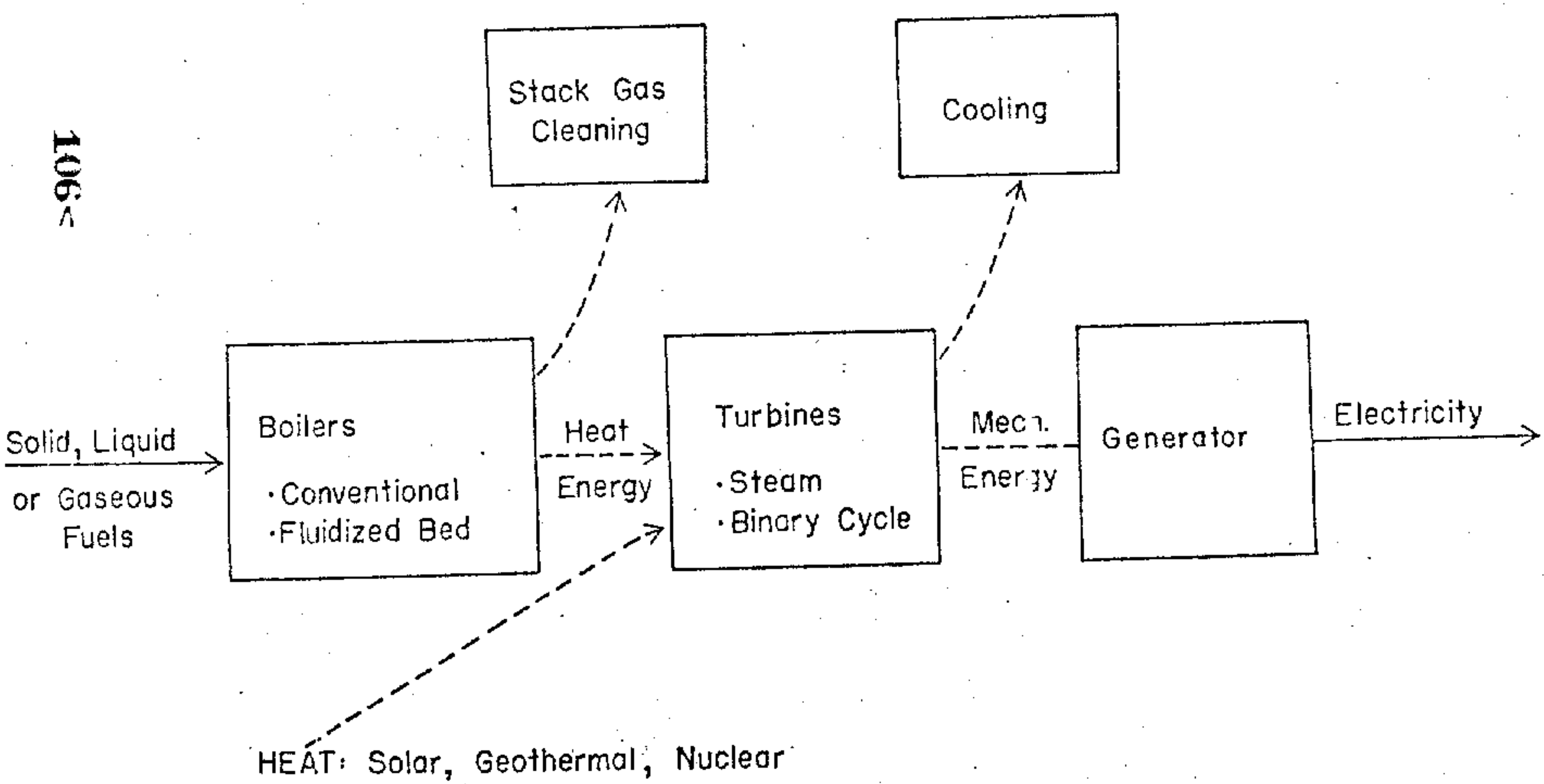
The cooling system in steam turbine technology is used during the second stage of this conversion process, to disperse the waste heat from the spent steam in the energy conversion process. It is not directly involved in creating electricity. After the steam exits the turbine, it is cooled in a condenser and reconverted to water. The water is sent back to the boiler to start the cycle anew. The heat retained in the condenser is then dispersed into the environment, usually through man-made cooling ponds and lakes, cooling towers or natural bodies of water.

Stack gas clean-up equipment is used to remove air pollutants from the combustion gases produced in boilers usually when coal is the primary fuel. The major pollutants from coal combustion are sulfur dioxide and particulate matter, such as soot or ash. Nitrogen oxides are also a major by-product, but these emissions are currently controlled through boiler configuration design, not through stack-gas clean-up.[1/] (Of growing concern to environmental authorities are carbon dioxide emissions, but these are not now controlled in conventional steam turbine plants.) After cleaning to acceptable levels

1/ Nitrogen oxides are also a pollutant from boilers using oil or natural gas. Acceptable emission levels as currently defined are attained through boiler design. Sulfur dioxide is also a major emission from high-sulfur residual oils. However, these have been controlled by switching to lower-sulfur feedstocks.

Figure 9-1

Boiler-Fired Power Plant.



determined by environmental regulation, these gases are released into the atmosphere.

Of the pollutants listed above, stack-gas clean-up equipment is currently designed for removal of the particulates and sulfur dioxide in combustion gases.

Removal of particulates can be accomplished either mechanically or electrostatically. For mechanical removal, the boiler combustion gases are sent through a "cyclone" unit, where centrifugal force separates the particulates from the gas and expels them to a collector for disposal. In electrostatic precipitators, the particulates are passed through an electric field where they are ionized and collected on a series of wires or tubes, then removed for disposal.

Sulfur dioxide emissions are currently reduced to acceptable levels either by burning lower-sulfur fuel in the boiler, or by the use of stack gas desulfurization equipment, commonly called "scrubbers." It should be noted that new coal-fired steam electric plants do not have an option; they must by law install scrubbers for sulfur dioxide control.

Basically, scrubbers reduce sulfur dioxide by passing the combustion gas over a reactant reactive with sulfur. The catalyst is usually lime or limestone, and the reaction produces a solid sulfur-containing compound ("sludge") which is either removed as solid waste, or treated to recapture the sulfur for resale in industrial markets.

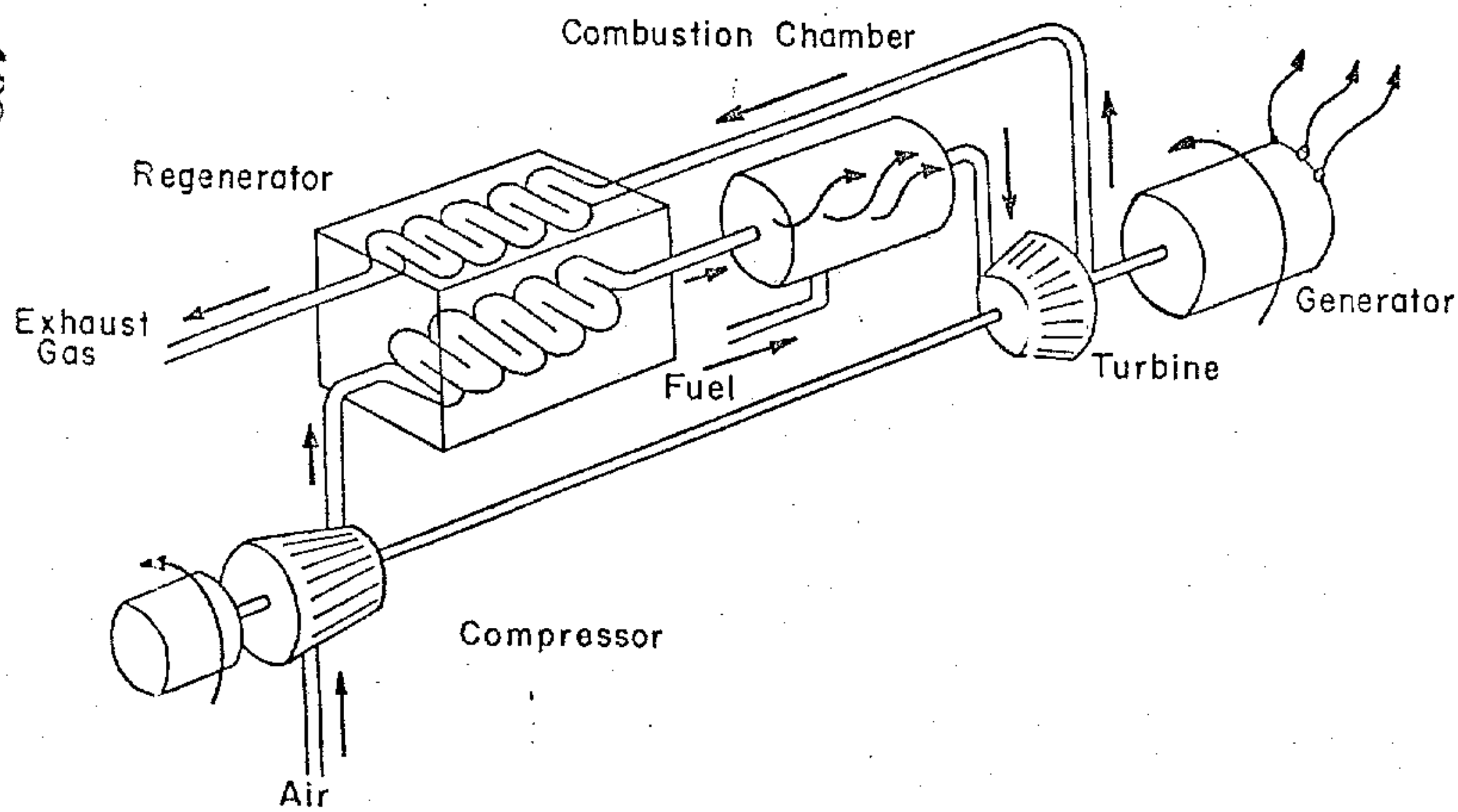
Gas Turbines

Gas turbine technology is similar in principal to the steam turbine technology discussed above. (See Figure 9-2.) Electricity is produced when the mechanical energy of the rotating turbine spins a generator that produces a current. However, the gas turbine does not use steam as the source of the heat energy required to turn its blades. Instead, it is similar to a jet engine in that it uses the combustion gases from the direct combustion of a liquid or gaseous fuel. The "gas" turbine gets its name from the combustion gas that drives its blades, not from the type of fuel it uses.

Since the gas turbine does not need steam, it does not need a boiler, which results in much faster start-up times for a gas turbine than for the conventional steam turbine. The gas turbine is typically ready for power production within minutes, while the steam turbine may not reach full steam temperature and pressure for several hours or more. The quick turn-around capability of the gas turbine makes it useful in peak demand situations of one or two hours duration.

Figure 9-2

GAS TURBINE



Because combustion gases from the primary fuel come in direct contact with the turbine blades of a gas turbine, it is very important that these gases be as clean and free as possible of corrosive components such as metals, particulates or salts. This necessitates the use of very clean fuel, such as distillate oil or natural gas.

The use of these fuels also results in negligible stack gas emissions of SO_2 and particulates. Nitrogen oxides, however, are a problem but are currently controlled through combustion chamber design or the injection of demineralized water into the chamber.

Combined-Cycle Technology

Gas turbine and steam turbine technology can be combined in one powerplant to take advantage of the waste heat in the hot gases exhausted from the gas turbine cycle. In the combined cycle plant, these hot exhaust gases are used to heat water to steam, which is then used to drive a conventional steam turbine. (See Figure 9-3.)

Because the combined-cycle plant converts more of the heat of fuel combustion into electricity, the thermal efficiency of the combined-cycle plant approaches 40 percent compared to about 24 percent for a simple gas turbine and 34 percent for a boiler-steam turbine.

Effect of Load Factor on Fuel Choice

A utility's choice of technology in making electricity heavily depends on the demand patterns of its customers. In general, the industry recognizes three levels of demand which influence plant design: baseload, intermediate load, and peak load demand.

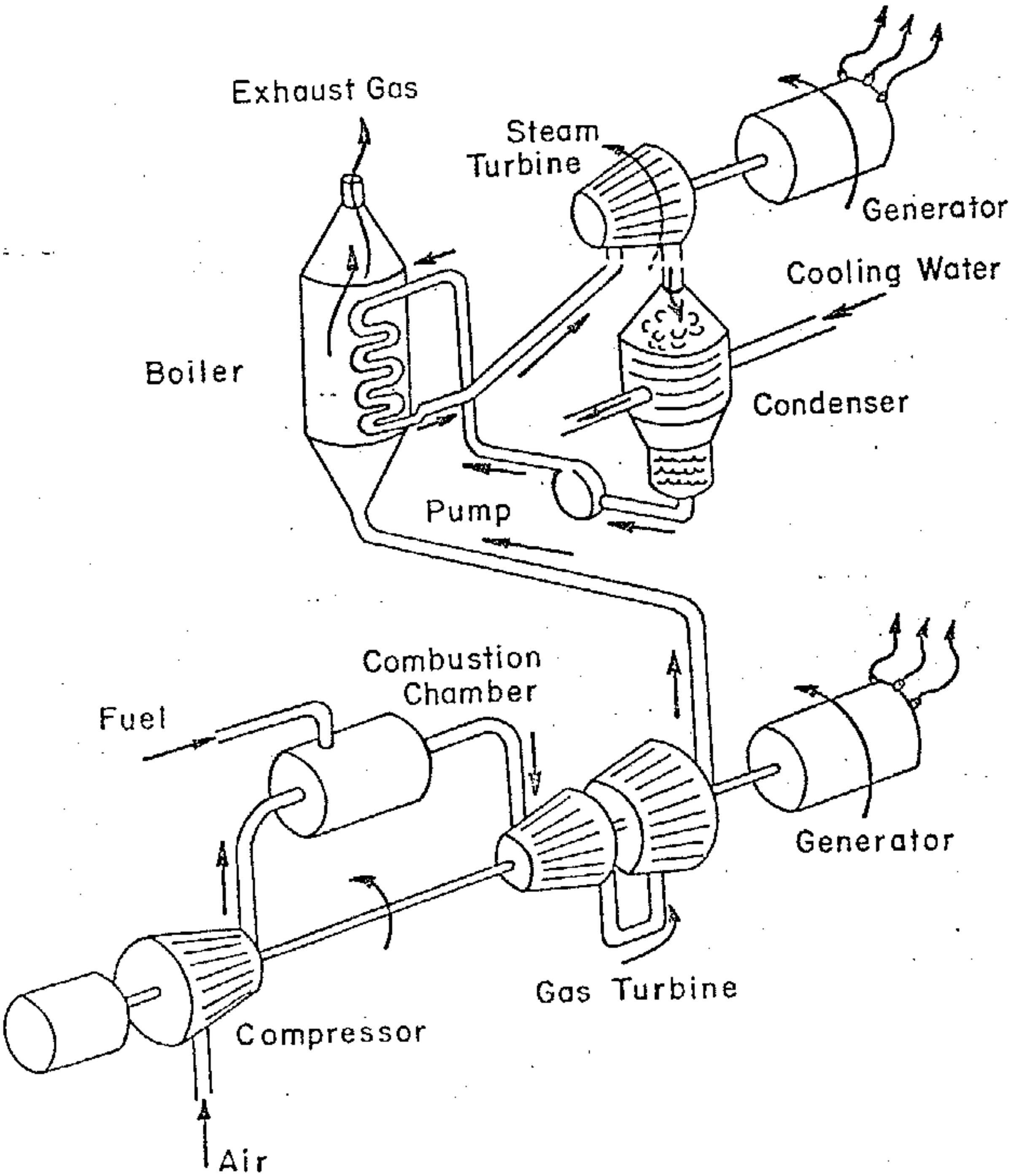
Baseload is the most constant portion of customer demand. Utilities generally construct large, relatively efficient and reliable units that operate continuously (from 60 to 80 percent of the time) to satisfy this demand. Boiler-fired steam turbines are commonly used as baseload technologies, and, depending on geographic location, can be fueled by coal, oil or natural gas.[1/] Nuclear plants and conventional hydroelectric plants are also generally designed for baseload operation.

Intermediate load is that portion of demand which varies on a daily or seasonal basis. Typically, intermediate load units are used to satisfy additional daily demands between 7 a.m. and midnight, or additional seasonal demands such as air conditioning use. Their utilization rate ranges nationwide from 20 to 60 percent of capacity, although "seasonal peak" utilization if often only 10 to 20 percent. They are usually smaller in

1/ Most baseload steam electric plants are fired with coal, except Gulf States, New England, and Southern California, where oil/gas in baseload predominates. In the Pacific Northwest, hydroelectric power is prominent.

Figure 9-3

COMBINED-CYCLE GAS TURBINE



size than baseload units, and generally are less efficient, hence more costly to operate. (Although their capital costs can be less than that of baseload.) However, their ability for faster start-up and shutdown than large baseload units makes their use practical. Today, intermediate load is most often served by smaller and older fossil-fuel steam turbine units. However, in the future, new coal-fired plants and combined-cycle units may become increasingly more important for intermediate loads. Seasonal peak is best served by oil and gas-fired steam turbines.

Peak load demand occurs on a daily basis, usually only for one to two hours at a time. It is the period when systemwide electricity demand is at its maximum, and is served by capacity that is small in size and can start-up or shutdown within minutes. Their utilization rate on an annual basis is quite low, ranging from 5 to 10 percent of availability. The gas turbine unit and the pumped-storage hydroelectric unit are the most suitable conventional technologies for peakload demands. As will be seen peak load service offers the best market for methanol.

CHAPTER 10

TECHNICAL AND ENVIRONMENTAL PERFORMANCE OF METHANOL IN ELECTRIC UTILITY EQUIPMENT

The purpose of this chapter is to describe the technical and environmental performance of methanol in boiler-steam turbine and gas turbine technologies.[1/] The discussion focuses on three criteria:

- thermal properties during combustion
- the impact of extended use on plant equipment
- uncontrolled emissions into the environment.

Each of these criteria will first be discussed below for use of methanol in boilers and then in a second section for use in gas turbines.

PERFORMANCE OF METHANOL IN BOILERS

Thermal Properties of Methanol

As discussed in Chapter 11, the purpose of the boiler in conventional utility technology is to provide sufficient heat to convert water into steam. The expansion of this steam against the blades of a turbine is the driving force which ultimately spins the generator and produces an electric current. The higher the steam pressure and temperature when it leaves the boiler, the greater the mechanical force exerted against the turbine blades. Thus, an important property of the fuel used in a utility boiler is its heat-producing capabilities. In physical chemistry, heat properties are generally evaluated in terms of the heat of combustion, flame luminosity and temperature, and heat of vaporization.

1/ Methanol use in a combined-cycle unit would affect only the gas turbine component on the unit; thus, the technical and environmental issues of methanol in a gas turbine generally indicate its performance in combined-cycle units.

Heat of Combustion

The heat of combustion is the most important factor in determining the heating ability of a fuel. It is commonly measured as the number of British Thermal Units (Btu's) released per pound of fuel burned. Residual grade oil, for example - the fuel used in most liquid-fired utility boilers - contains approximately 18,800 Btu's per pound of liquid. Methanol, however, contains about half of the heating value in residual oil (9,078 Btu/lb.). Thus, to be effective as a boiler fuel, about twice as much methanol per pound of steam must reach the combustion zone of the boiler to produce the same amount of electricity.

Current indications are that this can be accomplished in existing boilers with minimal technical difficulty. The major modification applies to the fuel storage and delivery system, to take account of the doubling in fuel flow (as well as some corrosive problems, discussed in the next section). Larger fuel pumps, valves, and nozzles may be required, for example.

Flame Luminosity and Temperature

The flame produced by methanol combustion is almost invisible. This is due to the chemical composition of the methanol molecule, which in pure form contains no carbon-carbon bonds and therefore does not produce unoxidized carbon particles (or soot) during combustion. These carbon particles are the source of luminosity in a flame. Generally, high flame luminosity is desirable for a boiler fuel because the luminosity represents radiant heat energy, which is readily transferred from the fuel combustion zone in the boiler to the outer regions where water circulates to receive the heat. This is a drawback of methanol fuel and can lead to a loss of thermal efficiency in the boiler. In one boiler test, for example, boiler efficiency was reduced three percent compared to natural gas at equal loads.[1/] Part of this was attributed to the lower luminosity of the flame and part to the lower temperature of the flame, another characteristic of methanol combustion.[2/]

Some analysts suggest, however, that the non-sooting characteristics of the methanol flame can offset the loss of radiant heat from low luminosity, particularly over sustained operating periods. This is because the lack of soot build-up on boiler walls results in a gain in conductive heat transfer through the boiler shell. (In fact, in a 1972 test at the A.B. Patterson powerplant in Louisiana, methanol removed the soot from the boiler walls from earlier oil burns.)

1/ R.W. Duhl and J.W. Boylan, "Use of Methanol as a Boiler Fuel." IVA-Symposium, Swedish Academy of Engineering Sciences, Stockholm, March 23, 1976.

2/ The flame temperature of methanol combusted in air has been estimated at 2194° Kelvin (3490° Fahrenheit). This is about 250° Kelvin (450° Fahrenheit) less than isooctane, a petroleum hydrocarbon.

Heat of Vaporization

Higher heat of vaporization is another characteristic of methanol fuel. This means that methanol requires more heat than other liquid fuels to reach the gaseous state prior to combustion. For boiler use, this may translate to more difficult and longer start-up periods compared to oil, and perhaps require the assistance of another fuel, such as natural gas, until the temperature in the boiler reaches sufficient levels to sustain combustion of the methanol liquid. However, the few tests to date give no indication that this is a significant problem. Furthermore, since boilers other than those used for peak load are generally operated continuously or for long durations once start-up has occurred, the effect of additional start-up time and costs on overall efficiency may be negligible. Sustained operational tests of methanol should help to resolve this question.

In summary then, the limited evidence now available on the use of methanol in boilers suggests that its heating properties are adequate for the boiler's steam production function. The major concern -- its lower heating value -- can be overcome by doubling the fuel delivery system. Other aspects -- heat transfer capabilities and start-up conditions -- are largely untested but probably will not pose significant problems. The impact of these should become better understood as long-term tests are con- ducted.

Impact on Equipment: Corrosivity and Lubricity

Because methanol is a potent solvent, its long-term use may swell or soften many of the plastic or rubber components used in conventional liquid fuel delivery systems. Gaskets or seals in fuel pumps are particularly vulnerable. Hence, use of methanol by utilities would probably require redesign or replacement of many existing plastics or rubbers to ensure their resistance to methanol corrosion.

Although such resistant components exist, their impact on operation and maintenance costs under long-term utility operations is not now known.

Methanol is also highly corrosive to many common metals or alloys; however, this has not been cited as a possible problem for utility boiler operations. However, corrosivity may impact upon fuel storage costs, especially in lead-plated tanks or those with aluminum, magnesium, copper, lead, zinc, or aluminum parts. Regular steel tanks are acceptable for methanol storage, so long as care is taken to remove water and salts from the tanks and fuel.

A final potential problem for the use of methanol is its poor lubricity compared to petroleum fuels. This impedes the operation of conventional utility fuel pumps, which receive lubrication from the fuel itself. Possible technical solutions include the use of a centrifugal pump instead of the standard positive displacement pump, since the centrifugal pump allows the addition of external lubricants to the fuel.

Emissions

The use of methanol in boilers may substantially reduce the levels of sulfur dioxide (SO_2), total suspended particulate matter (TSP), and nitrogen oxides (NO_x) emitted by conventional oil and gas steam turbine plants. In the limited boiler tests of methanol done to date, engineers found no SO_2 or TSP emissions in the methanol exhaust gases, and NO_x emissions were seventy-five to ninety percent less than that of gas or oil, respectively.1/

The lack of SO_2 emissions, of course, occurs because methanol fuel contains no sulfur; as noted all sulfur is removed in methanol production because the catalyst used in methanol synthesis will not tolerate sulfur impurities. Residual oil, the most commonly used petroleum fuel in boilers, does contain sulfur in varying levels depending on the crude oil source and extent of subsequent refining.

As discussed earlier, TSP (or soot) does not form during methanol combustion because the fuel contains no carbon-carbon bonds which could lead to particulate matter in the form of unburnt fuel.

Finally, NO_x emissions are reduced because the methanol flame temperature is lower than that of oil or gas. Researchers believe that NO_x is formed in the immediate vicinity of fuel combustion, particularly near the fuel nozzle. Since NO_x formation increases as temperature increases, the lower flame temperature of methanol compared to oil or gas is thought to explain the lower emission result.

The Environmental Protection Agency does not currently regulate steam-turbine emissions of carbon monoxide (CO) or aldehydes (C_2O), but these are also produced in the combustion gas of methanol in boilers. However, in the largest boiler demonstration test to date, the carbon monoxide emissions were less than those formed with oil or gas at equal loads, and the aldehydes were considered insignificant at levels of 1 to 10 parts per million.

Additional testing and research is probably required, however, before definitive answers about the emissions of methanol in large-sized boilers under sustained operation can be known.

1/ For a discussion of methanol emission test results in boilers (and gas turbines), see "Methanol as a Fuel: A Review with Bibliography," David L. Hagen, Paper 77092 presented at the Passenger Car Meeting, Detroit, Michigan, September 1977.

PERFORMANCE OF METHANOL IN GAS TURBINES

A distinction should be made between methanol use in existing turbines and in new turbines. The problems to be discussed here are problems to be "coped with" in existing units and "designed for" in new systems. A new turbine can probably be designed for any fuel, but if methanol is confined to new units its penetration as a utility fuel will obviously be slowed.

Thermal Properties

A gas turbine is driven directly by the hot gases produced by combustion and not by steam as in the boiler technology described previously.

Thus, the temperature of the gas from combustion is a critical factor in the successful production of electricity in a gas turbine. As with boilers, this translates to a need for Btu's per kilowatt.1/ Because methanol use means doubling the fuel flow rate, the gas turbine systems would include the same fuel storage and delivery problems mentioned in the boiler section above. However, researchers indicate that in the limited gas turbine tests to date, equipment modifications due to increased fuel flow are considered minimal.

An additional consideration for methanol combustion in gas turbines is its tendency to explode. Sustained operational tests may prove that explosion proofing of combustion chambers is warranted. The impact of this on design, construction or modification costs to conventional gas turbine models has not been estimated.

Impact on Equipment: Corrosivity and Lubricity

Methanol use in gas turbines is likely to present some of the same fuel delivery system corrosion and lubricity problems as discussed earlier for boiler systems (i.e. corrosion of fuel tanks, swelling of plastics or rubbers in fuel pumps, etc.). However, the clean-burning characteristics of methanol make it an ideal fuel for gas turbine use. This is because the blades in the turbine are highly sensitive to hot corrosion from sulfur, metals or particulates in the fuel exhaust gases; since methanol exhaust possesses virtually no sulfur, metallic content or particulates, corrosion of turbine blades may be reduced with its use. A problem with salt corrosion may be

1/ However, a gas turbine is less efficient than a steam turbine, because more of the heat of combustion is wasted as exhaust heat from the turbine. The gas turbine therefore requires about 12,000 Btu per kilowatt-hours of electricity production (compared to about 9,600 Btu per kilowatt-hour for steam systems). Combined-cycle units - a gas turbine and a steam turbine in tandem - are intended to improve this performance by using this exhaust to produce steam in a waste-heat boiler for use in an attached steam turbine.

encountered if water is present in the methanol; methanol, unlike petroleum, is able to completely mix with water. However, this could be avoided by taking care in the storage and distribution system to keep the fuel dry and free of sodium.

Emissions

Similar results occur for emissions of SO_2, TSP, and NO_x in gas turbine use as was found in boilers: methanol combustion gases are virtually free of the first two, and significantly lower in the latter when compared to oil or natural gas.

Carbon monoxide emissions may be more of a problem in gas turbines than in boilers, however, because of the combustion chamber design. It is thought that higher CO emissions are formed from burning methanol primarily because the desired CO to CO_2 reaction in the combustion chamber is quenched too quickly, thereby resulting in more CO than for other fuels. Researchers suggest that redesign of the combustion chamber, such as moving the air-dilution ("quenching") ports further downstream, may solve this problem. The costs of such modifications are unknown, however.

Finally, aldehydes are also emitted during gas turbine use, but these may not be a significant problem. A recent EPRI test of methanol in a gas turbine found, for example, that the aldehyde emissions were no greater than those emitted from the burning of natural gas. It is believed that aldehyde control technology would probably not be required.

CHAPTER 11

COST COMPARISONS OF SYNFUELS FOR ELECTRIC UTILITIES

Chapter 10 reported that methanol may well become an acceptable utility fuel on the basis of technical and environmental performance. The purpose of this chapter is to determine whether or not methanol could also be an economical fuel choice for utilities.

Because a utility's choice of fuel depends not only on interfuel competition within a given technology, but also on the competitiveness of that technology against the array of others available for electricity generation, the analysis of the economic use of methanol in the utility sector can be split into two questions.

- First, does methanol ever prove cost competitive with other liquid or gaseous fuels to be used in gas turbines, combined-cycle units, and existing oil/gas-fired boilers. That is, does it prove cost competitive in technologies that must use liquid or gaseous fuels?

- Second, do these "liquid and gas" technologies represent a better economic choice for a utility than an alternative generating method, such as a coal plant or a hydro plant, in base, intermediate or peak load service?

The first section in this chapter addresses the first question raised above while the second section tackles the second question.

METHANOL VERSUS OTHER LIQUID AND GASEOUS FUELS

It's assumed for the purposes of this analysis that methanol as well as the residual and distillate from direct liquefaction can be used without significant equipment modifications in gas turbines, combined cycle facilities, and in conventional oil and gas-fired boilers. With this assumption a cost comparison among competing fuels is reduced to a simple comparison of delivered fuel prices; that is, equipment, operation and maintenance costs will not vary by fuel type.

This issue of the need for modification is most important for existing turbines. That equipment could have been designed for very specific technical standards not met by one or all of these synthetics. New turbines can probably be designed and optimized for any of these fuels although there is some question as to which type of turbine would cost more to buy and to operate. As noted before, if methanol use is confined to new units its penetration as a utility fuel will be slowed.

As with the auto cost comparisons, one can explore variations due to the extent or scale of methanol use, the location of consumption, and the date of use.

Extent of Methanol Use

The move toward large scale methanol use does not appear to be as important here as it was to the auto cost comparisons. Only the method of transport changes--for small scale, railroads are used for all synfuels, but for the large scale situation methanol and distillate can enjoy the lower rates of pipeline transportation. Residual is presumed to always use rail transport because it is too viscus to pipe.

Table 11-1 presents the comparisons assuming rail transport and Table 11-2 shows the same comparisons assuming pipeline transport for methanol and distillate. All the comparisons are summarized in Table 11-3. The figures in the summary table are differences in the delivered price of the fuels; that difference is measured in terms of $1980 per MMBtu.

Of the twelve rail cases, methanol is shown to have a cost advantage in only one. Methanol's cost disadvantage ranges from $.39 to $1.99 per MMBtu. With the pipeline transport, methanol's cost disadvantage is cut substantially, but in only two of the twelve cases is methanol shown to be cheaper; in the other ten cases the disadvantage ranges from $.39 to $1.57 per MMBtu.

These comparisons reveal the importance of the assumed relationship among the prices for the products of direct liquefaction. It is assumed here that low sulfur residual oil would be sold at a price which is 77 percent of the gasoline price. A change could be made in the assumption concerning that price relationship so that resid prices are higher and methanol compares more favorably as a utility fuel. A higher resid price here, however, necessarily means a lower gasoline price back in Chapter 7, and perhaps, a cut in methanol's cost advantage as an auto fuel. The price relationship for direct liquefaction is important because it dictates the cost allocation among products. If producers are assumed to get a higher price for residual oil, less of the production cost must be recouped with gasoline sales so the gasoline price can be lowered.

Mention should also be made of the assumption concerning equipment modifications. That is, the assumption that no equipment modifications are

TABLE 11-1

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATES IN 1990 TO CHICAGO USING RAIL FOR TRANSPORTING ALL FUELS
($1980 per MMBtu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	8.94	7.02	7.10	6.16	7.04	6.60	5.94	6.32
Long Haul Transport	.57	.57	.57	.57	.24	.24	.24	.26
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	10.38	8.46	8.54	7.60	7.65	7.21	6.55	6.98

TABLE 11-2

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE IN 1990 TO CHICAGO USING PIPELINE FOR TRANSPORTING METHANOL AND DISTILLATE AND RAIL FOR TRANSPORTING RESIDUAL OIL
($1980 per MMBtu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	8.94	7.02	7.10	6.16	7.04	6.60	5.94	6.32
Long Haul Transport	.15	.15	.15	.15	.24	.24	.24	.07
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	9.96	8.04	8.12	7.18	7.65	7.21	6.55	6.79

TABLE 11-3

SUMMARY OF UTILITY COST COMPARISONS BETWEEN METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE TO CHICAGO IN 1990[a/]
(Differences in Delivered Fuel Prices)

	SRC II Residual		EDS Residual		H-Coal Residual		H-Coal Distillate	
	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline
Badger	(.81)	(.39)	(1.25)	(.83)	(1.91)	(1.49)	(1.48)	(1.25)
Texaco	(.89)	(.47)	(1.33)	(.91)	(1.99)	(1.57)	(1.56)	(1.33)
BGC/LURGI	.05	.47	(.34)	.03	(1.05)	(.63)	(.62)	(.39)

a/ Differences equal the cost of methanol minus the cost of the synthetic resid or distillate. A bracketed number means methanol is more expensive. This table summarizes the results of the two previous tables.

necessary for gas turbines using any synfuel. Clearly methanol will be a much cleaner fuel than the residual fuels--methanol will not, for example, generate any sulfur dioxide or particulates. On the other hand, methanol use may, as explained in Chapter 10, require changes to the fuel delivery system in terms of size and materials and the design of explosion-proof chambers.

There was not sufficient time to resolve this issue of relative cost of equipment modification and that's unfortunate. Less than $1.00 per million Btu typically separates methanol and residual from EDS and SRC-II. Although the synthetic resid shown here is very low in sulfur and other impurities, it is not inconceivable that the gap could be closed if that residual oil had to be refined further for use in turbines. In addition, that gap could be closed if, as will be explained in Chapter 12, methanol was given credit through environmental regulations for being a cleaner fuel.

Location

As in the auto cost comparisons, the effect of increasing transportation distances is illustrated by showing comparisons for synfuels produced in Illinois and shipped to New York. Table 11-4 displays cost comparisons assuming rail transport for all synfuels and 11-5 does the same assuming pipeline transport for methanol and distillate. A summary of the cost comparisons is shown in Table 11-5.

In the small scale or railroad situations, the longer distance to New York only increases methanol's cost disadvantage. That disadvantage ranges from $1.04 to $3.09 per MMBtu. With pipeline transport, however, methanol's cost competitiveness is actually increased with longer distances because resid is forced to continue its use of the railroads. Still methanol is at a cost disadvantage in ten of twelve cases and that disadvantage ranges from $.09 to $1.60 per MMBtu.

Timing

In the auto comparisons, methanol's cost advantage grew over time. As noted, this should be expected since just about equal percentage cost increases are assumed for methanol and the synthetic gasoline so methanol's initial production cost advantage will also grow by that same percentage. Methanol does not have that initial production cost advantage when compared to residual so methanol cannot be expected to do better over time in these utility cost comparisons.

Table 11-7 and 11-8 show the small and large scale situations for fuels shipped to Chicago in 2000. Those comparisons are summarized in Table 11-9. Although methanol's cost disadvantage is cut to some extent, it is cheaper in only one small scale and two large scale situations. With the small scale distribution, the disadvantage ranges from $.36 to $1.97 per MMBtu. With large scale distribution the disadvantage narrows to $.04 to $1.55.

TABLE 11-4

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE IN 1990 TO NEW YORK USING RAIL FOR TRANSPORTING ALL FUELS
($1980 per MMBtu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	8.94	7.02	7.10	6.16	7.04	6.60	5.94	6.32
Long Haul Transport	2.47	2.47	2.47	2.47	1.04	1.04	1.04	1.12
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	12.28	10.36	10.44	9.50	8.45	8.01	7.35	7.84

TABLE 11-5

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE IN 1990 TO NEW YORK USING PIPELINE FOR TRANSPORTING METHANOL AND DISTILLATE AND RAIL FOR TRANSPORTING RESIDUAL OIL
($1980 per MMBTu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	8.94	7.02	7.10	6.16	7.04	6.60	5.94	6.32
Long Haul Transport	.65	.65	.65	.65	1.04	1.04	1.04	.30
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	10.46	8.54	8.62	7.68	8.45	8.01	7.35	7.02

TABLE 11-6

SUMMARY OF UTILITY COST COMPARISONS BETWEEN METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE TO NEW YORK IN 1990[a/]
(Differences in Delivered Fuel Prices)

	SRC II Residual		EDS Residual		H-Coal Residual		H-Coal Distillate	
	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline
Badger	(1.90)	(.09)	(2.35)	(.53)	(3.01)	(1.19)	(2.52)	(1.52)
Texaco	(1.98)	(.17)	(2.43)	(.61)	(3.09)	(1.27)	(2.60)	(1.60)
BGE/LURGI	(1.04)	.77	(1.49)	.33	(2.15)	(.33)	(1.66)	(.66)

a/ Differences equal the cost of methanol minus the cost of the synthetic resid or distillate. A bracketed number means methanol is more expensive. This table summarizes the results of the two previous tables.

TABLE 11-7

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE IN 2000 TO CHICAGO USING RAIL FOR TRANSPORTING ALL FUELS
($1980 per MMBtu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	10.36	8.09	8.19	7.10	8.56	7.90	7.05	7.51
Long Haul Transport	.57	.57	.57	.57	.24	.24	.24	.26
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	11.80	9.53	9.63	8.54	9.17	8.51	7.66	8.17

TABLE 11-8

UTILITY COST COMPARISON: METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE IN 2000 TO CHICAGO USING PIPELINE FOR TRANSPORTING METHANOL AND DISTILLATE AND RAIL FOR TRANSPORTING RESIDUAL OIL
($1980 per MMBTu)

	Koppers-Totzek Methanol	Badger Methanol	Texaco Methanol	BGC/Lurgi Methanol	SRCII Residual	EDS Residual	H-Coal Residual	H-Coal Distillate
Plant Gate Cost	10.36	8.09	8.19	7.10	8.56	7.90	7.05	7.51
Long Haul Transport	.15	.15	.15	.15	.24	.24	.24	.07
Local Distribution	.87	.87	.87	.87	.37	.37	.37	.40
Total Delivered Price	11.38	9.11	9.21	8.12	9.17	8.51	7.66	7.98

TABLE 11-9

SUMMARY OF UTILITY COST COMPARISONS BETWEEN METHANOL AND SYNTHETIC RESIDUAL OR DISTILLATE TO CHICAGO IN 2000[a/]
(Differences in Delivered Fuel Prices)

	SRC II Residual		EDS Residual		H-Coal Residual		H-Coal Distillate	
	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline	Rail	Pipeline
Badger	(.36)	.06	(1.02)	(.60)	(1.87)	(1.45)	(1.36)	(1.13)
Texaco	(.46)	(.04)	(1.12)	(.70)	(1.97)	(1.55)	(1.46)	(1.24)
BGC/LURGI	.63	1.05	(.03)	.39	(.88)	(.46)	(.37)	(.18)

a/ Differences equal the cost of methanol minus the cost of the synthetic resid or distillate. A bracketed number means methanol is more expensive. This table summarizes the results of the two previous tables.

LIQUID AND GAS TECHNOLOGIES VERSUS COAL

It's possible that methanol may become competitive with conventional distillate or residual fuels and yet not find a place in electric utilities because no liquid fuel technology can beat conventional coal systems. The purpose of this section is to compare the cost of coal and liquid technologies. That is, to compare liquid-fired boilers and combined-cycle units to conventional coal boilers.

Two points must be discussed before the cost comparisons can be understood. First, the comparisons are for either new or existing equipment and the distinction is quite important. The cost for a new system includes both equipment and operating cost while for an existing system only operating costs are shown because capital expense is considered unaffected by the fuel choice.

A second point is that all liquids - methanol as well as conventional and synthetic oil products - are sold at an assumed world oil price of $32 per barrel of average crude in 1980 rising at 2 percent per year in real terms. Although the cost comparisons may have shown methanol or another synthetic to be cheaper to produce and deliver, it is unlikely that its selling price would actually be lower; OPEC is likely to set the price for liquid fuels for the foreseeable future.

With these two points in mind, four cost comparisons can be studied.

New Liquid and Coal-Fired Boilers

Table 11-10 compares the cost of producing electricity with either a new liquids-fired or a new coal-fired boiler/steam turbine. The costs per kilowatt-hour are shown at four load factors - base, intermediate, seasonal peak, and daily peak. Note that the comparison for peak is for reference only; even if the cost comparison showed a coal-fired unit to be the least cost system it's unlikely that it would be used because its start-up time may be too long for peak service.

Except for the peak service, a coal-fired system is always less expensive than the liquids unit. To show just how much cheaper, a breakeven liquids price annuity is shown at the bottom of the page. For example, for the baseload plant, liquid fuels would have to sell for $3.25 per MMBtu in order to produce electricity at the same cost as the coal-fired system; this would amount to more than a 60 percent cut below the assumed liquids price annuity. In all three cases, the breakeven price annuity for liquids is well below that assumed for this report.

Existing Liquids-Fired and New Coal-Fired Boilers/Steam Turbine

Table 11-11 compares the cost of keeping an existing liquids system to the cost of scrapping that system and replacing it with a brand new coal-fired unit. The table shows that in both base and intermediate-load, electricity

TABLE 11-10

COST COMPARISON OF NEW LIQUIDS AND NEW COAL-FIRED BOILERS/STEAM TURBINE

On Line Date: 1990	Baseload (70% Utilization)		Intermediate (50% Utilization)		Seasonal Peak (25% Utilization)		Peak (5% Utilization)	
	Liquids	Coal	Liquids	Coal	Liquids	Coal	Liquids	Coal
CAPITAL COSTS								
Capital ($/kw)	600	1,000	600	1,000	600	1,000	600	1,000
Real Capital Charge Rate	.10	.10	.10	.10	.10	.10	.10	.10
Annual Capital Cost ($/kw/yr)	60	100	60	100	60	100	60	100
Capacity Factor	.70	.70	.50	.50	.25	.25	.05	.05
Hrs/yr of generation	6,132	6,132	4,380	4,380	2,190	2,190	438	438
Annualized Capital Costs (mills/kwh)	9.8	16.3	13.7	22.8	27.4	45.6	136.9	228.3
FUEL COSTS								
Annualized Fuel Cost ($/MMBtu) a/	8.40	2.00	8.40	2.00	8.40	2.00	8.40	2.00
Heat Rate (Btu/kwh)	9,300	9,700	9,600	10,000	10,300	10,700	11,000	15,000 b/
Fuel Cost (mills/kwh)	78.1	19.4	80.6	20.0	86.5	21.4	92.4	30.0
Operation & Maintenance (mills/kwh)	0.5	4.8	0.8	5.5	1.5	7.7	7.5	25.8
Total Annualized Cost (1980 mills per kwh)	88.4	40.5	95.1	48.3	115.4	74.7	236.8	284.1
Breakeven Liquids Annuity ($/MMBtu) c/	3.25		3.51		4.45			

a/ Assumes residual fuel prices for liquids and high sulfur coal prices.

b/ This reflects technical problems associated with running a coal plant at such low utilization rates.

c/ This represents the price at which liquids would have to sell for the liquids and coal systems to be equal in costs.

TABLE 11-11

COST COMPARISON OF EXISTING LIQUIDS-FIRED AND NEW COAL-FIRED BOILER/STEAM TURBINES

	On Line Date: 1990							
	Baseload (70% Utilization)		Intermediate (50% Utilization)		Seasonal Peak (25% Utilization)		Peak (5% Utilization)	
	Liquids	Coal	Liquids	Coal	Liquids	Coal	Liquids	Coal
CAPITAL COSTS								
Capital ($/kw)	0	1,000	0	1,000	0	1,000	0	1,000
Real Capital Charge Rate	0	.10	0	.10	0	.10	0	.10
Annual Capital Cost ($/kw/yr)	0	100	0	100	0	100	0	100
Capacity Factor	.70	.70	.50	.50	.25	.25	.05	.05
Hrs/yr of generation	6,132	6,132	4,380	4,380	2,190	2,190	438	438
Annualized Capital Costs (mills/kwh)	0	16.3	0	22.8	0	45.6	0	228.3
FUEL COSTS								
First-yr Fuel Cost ($/MMBtu)a/	6.66	2.00	6.66	2.00	6.66	2.00	6.66	2.00
Heat Rate (Btu/kwh)	9,300	9,700	9,600	10,000	10,300	10,700	11,000	15,000b/
Fuel Cost (mills/kwh)	61.9	19.4	63.9	20.0	68.6	21.4	73.3	30.0
Operation & Maintenance (mills/kwh)	0.5	4.8	0.8	5.5	1.5	7.7	7.5	25.8
Total Annualized Cost (1980 mills per kwh)	62.4	40.5	64.7	48.3	70.1	74.7	80.8	284.1
Breakeven First-yr Price ($/MMBtu)c/	4.30		4.95					

a/ Assumes 1990 price of residual fuel (in 1980$).

b/ This reflects technical problems associated with running a coal plant at such low utilization rate.

c/ This represents the price at which liquids would have to sell for the liquids and coal systems to be equal in cost.

could be produced more cheaply if the liquids system was replaced. Only with the seasonal and peak load factors would the existing liquids system produce electricity at a lower cost than the coal-fired unit. The breakeven liquids prices shown at the bottom of the table indicate that about a thirty percent drop would be necessary for liquids to compete with the coal system in base and intermediate-load.

New Liquids-Fired Combined Cycle Versus New Coal-Fired Boiler/Steam Turbine

Liquids may fare better in a comparison with coal if those liquids are used in combined-cycle units. Oil can compete with such technology for two reasons; equipment costs are lower and fuel efficiency is higher.

Table 11-12 compares the cost of producing electricity with a new liquids-fired combined cycle unit to that with a new coal-fired boiler/steam turbine. The coal-fired system wins the competition in all but the peak-load service.

Liquids Versus Coal-In Existing Coal Capable Units

Many powerplants in the eastern United States once burned coal but in the 1960's turned to oil and gas. Such units are termed coal-capable and they have been a target for federal regulation since 1974. In that year, the federal government was given the authority to prohibit conventional oil and gas use in coal-capable powerplants. These units, faced with a prohibition order, could switch to coal or to synthetic fuels such as methanol.

Table 11-13 displays a comparison of the cost for producing electricity in a coal-capable boiler with liquids or with coal. Note that the liquids could be used without equipment modification while some modification expense is assumed to be incurred with coal.[1/] Once again, the coal-fired system is bound to be lower cost.

1/ In reality, a cost would be associated with installing fuel delivery system modification to existing oil plants to use fuels like methanol. However, no costs are available on this expense. Since engineers believe it to be minimal, we have assumed a zero cost for this comparison.

TABLE 11-12

COST COMPARISON OF A NEW LIQUIDS-FIRED COMBINED CYCLE UNIT VERSUS A NEW COAL-FIRED BOILER/STEAM TURBINE

	On Line Date: 1990							
	Baseload (70% Utilization)		Intermediate (50% Utilization)		Seasonal Peak (25% Utilization)		Peak (5% Utilization)	
	Liquids	Coal	Liquids	Coal	Liquids	Coal	Liquids	Coal
CAPITAL COSTS								
Capital ($/kw)	378	1,000	378	1,000	378	1,000	378	1,000
Real Capital Charge Rate	.1	.1	.1	.1	.1	.1	.1	.1
Annual Capital Cost ($/kw/yr)	37.8	100	37.8	100	37.8	100	37.8	100
Capacity Factor	.70	.70	.50	.50	.25	.25	.05	.05
Hrs/yr of generation	6,132	6,132	4,380	4,380	2,190	2,190	438	438
Annualized Capital Costs (mills/kwh)	6.2	16.3	8.6	22.8	17.3	45.6	86.3	228.3
FUEL COSTS								
Annualized Fuel Cost ($/MMBtu)a/	8.91	2.00	8.91	2.00	8.91	2.00	8.91	2.00
Heat Rate (Btu/kwh)	8,200	9,700	8,600	10,000	10,000	10,700	15,000	15,000b/
Fuel Cost (mills/kwh)	73.1	19.4	76.6	20.0	89.1	21.4	133.4	30.0
Operation & Maintenance (mills/kwh)	1.3	4.8	1.9	5.5	3.7	7.7	18.6	25.8
Total Annualized Cost (1980 mills per kwh)	80.6	40.5	87.1	48.3	110.1	74.7	238.3	284.1
Breakeven Price Annuityc/	4.02		4.40		5.37			

a/ Assumes distillate fuel prices for liquids and high sulfur coal prices.

b/ This reflects technical problems associated with running a coal plant at such low utilization rates.

c/ This represents the pice at which liquids would have to sell for the liquids and coal systems to be equal in costs.

TABLE 11-13

COST COMPARISON OF LIQUIDS AND COAL IN AN EXISTING COAL-CAPABLE BOILER/STEAM TURBINE

On Line Date: 1990

	Baseload (70% Utilization)		Intermediate (50% Utilization)		Seasonal Peak (25% Utilization)		Peak (5% Utilization)	
	Liquids	Coal	Liquids	Coal	Liquids	Coal	Liquids	Coal
CAPITAL COSTS								
Capital ($/kw)	0	505	0	505	0	505	0	505
Real Capital Charge Rate	0	.15	0	.15	0	.15	0	.15
Annual Capital Cost ($/kw/yr)	0	75.8	0	75.8	0	75.8	0	75.8
Capacity Factor	.70	.70	.50	.50	.25	.25	.05	.05
Hrs/yr of generation	6,132	6,132	4,380	4,380	2,190	2,190	438	438
Annualized Capital Costs (mills/kwh)	0	12.4	0	17.3	0	34.6	0	173.1
FUEL COSTS								
First-yr Fuel Cost ($/MMBtu)a/	6.66	2.00	6.66	2.00	6.66	2.00	6.66	2.00
Heat Rate (Btu/kwh)	9,300	10,000	9,600	10,300	10,300	11,000	11,000	15,300b/
Fuel Cost (mills/kwh)	61.9	20.0	63.9	20.6	68.6	22.0	73.3	30.6
Operation & Maintenance (mills/kwh)	0.5	4.8	0.8	5.5	1.5	7.7	7.5	25.8
Total Annualized Cost (1980 mills per kwh)	62.4	37.2	64.7	43.4	70.1	64.3	80.8	229.5
Breakeven First-yr Price ($/MMBtu)c/	3.95		4.44		6.10			

a/ Assumes 1990 price of residual oil (in 1980 $) for liquids and high sulfur coal prices.

b/ This reflects technical problems associated with running a coal plant at such low utilization rates.

c/ This represents the price at which liquids would have to sell for the liquids and coal systems to be equal in costs.

CHAPTER 12

MARKET PROJECTIONS FOR ELECTRIC UTILITIES

If utility fuel choice was determined by simple cost comparisons, the examples in the previous chapter would lead one to believe that the market for methanol or any liquid or gaseous fuel would be in daily peak-load facilities and for existing oil and gas-fired boilers/steam turbines used to serve seasonal peak demand.

High cost is not the only impetus for a move away from oil and gas use by electric utilities. Government energy regulations also push in this direction. More specifically, the Powerplant and Industrial Fuel Use Act contains the following provision:

- Prohibits the construction of new plants for conventional oil and gas, except for peak load.

- Forbids gas use by any powerplant after 1990; once again peak serving units are not included.

- Grants authority to DOE to order coal-capable plants now burning oil and gas to switch to coal or another alternate fuel.

Despite the fact utilities are encouraged to abandon oil and gas use by both economics and edict, a market for liquids and gases is expected to remain. It is the purpose of this chapter to give some indication of the size of this market. The basis for this discussion is the latest run of ICF's Coal and Electric Utilities Model; that model run is the topic for the first section of the report. A brief discussion of environmental regulations and methanol demand serves as the second section of this chapter.

CEUM PROJECTIONS

Recent computer runs of the ICF Coal and Electric Utilities Model (CEUM) indicate that given certain assumptions about future oil and gas prices, government regulations, and utility attitudes toward coal investments, oil and gas use by utilities is expected to decline steadily.

Table 12-1, for example, shows the projected capacity mix of generating technologies from 1985 through 1995 by fuel type. Between 1985 and 1995, total generating capacity is expected to increase from 592 GW to 789 GW, yet the amount of oil/gas capacity that will be needed to generate electricity will decline by 27 GW. Most of this decline can be traced to the oil/gas steam turbine market.

TABLE 12-1

PROJECTED UTILITY GENERATING CAPACITY
(Gigawatts)

	1985	1990	1995
Coal Plant Capacity	275	325	419
Oil/Gas Plant Capacity			
• Steam Turbine	125	115	98
• Gas Turbine	35	33	38
• Combined Cycle	6	4	3
	166	152	139
Nuclear	72	116	140
Hydro/Other	79	85	91
Total Generating Capacity	592	678	789

Table 12-2 shows the amount of fossil-fuels that would be used by this generating capacity.

TABLE 12-2

PROJECTED UTILITY FOSSIL-FUEL CONSUMPTION
(10^{15} Btu)

	1985	1990	1995
Oil/Gas			
• Gas	3.2	2.7	1.8
• Residual Oil	1.7	1.2	.8
• Distillate Oil	.4	.1	.1
	5.3	4.0	2.7
Coal	15.3	18.1	23.1
Total Fossil-Fuels	20.6	22.1	25.8

Although this result is dependent upon the interplay of all the assumptions on electricity demand, load patterns, capital and operating costs, etc., a few assumptions on oil and gas prices and availability explain much of the apparent decline in oil/gas utility use. These assumptions are as follows:

- Oil Prices: Crude oil prices are $32/BBL delivered to Texas in 1980, and rise at the rate of 2 percent per year in real terms. Higher prices or higher rates of increase could depress the oil/gas demand further.

- Natural Gas Prices: Natural gas prices are assumed to be deregulated in 1985. The price is expected to be comparable to that of residual oil. It is also assumed that utilities now using gas would not be forced to switch to other fuels by DOE in 1990. However, they can burn only as much gas as they did in the highest consumption year between 1970 and 1980.

- Oil Replacement Program: To take account of the effects of PIFUA, it is assumed that some existing oil/gas capacity will switch to other fuels. For example, about 15 GW of "coal-capable" oil plants (i.e. those that formerly burned coal before converting to oil/gas) are assumed to go back to coal by 1985. Furthermore, some "accelerated replacement" of oil plants is assumed to occur by 1990, meaning that those plants will be retired in favor of building an entirely new coal plant.

- Oil/Gas Consumption Limited: Because it is recognized that utility oil/gas use is based partly on economics, partly on government policy, and partly on utility attitudes, and that much of this cannot be precisely determined, an assumption is made about total oil/gas consumption by 1985 and thereafter. The assumption is that a maximum of 5.3 quads of oil/gas (approximately 2.5 million bbl/day oil equivalent) will be consumed in 1985. This will decline to 2.7 quads of oil/gas (1.3 million bbl/day oil equivalent) by 1995. The key factors slowing the move to coal are the large investment required and the practical limits to the number of plants that can be built over the next decade.

Although Chapter 11 illustrated that there are very few situations where liquid fuels are likely to be more economical than coal (including even oil plants already built), the CEUM computer results show that when other factors besides economics are accounted for, utility consumption of oil and gas will continue through 1995, but in decreasing amounts. Thus, if methanol is competitive with oil prices during this time it is conceivable that methanol could garner a share of this oil/gas market. For example, as shown in Table 12-3, total peak load demand for oil and gas is about .34 quadrillion Btu (quads) in 1990 and .41 quads in 1995. This is the prime target for methanol or any liquid/gas fuel and it may be expected to grow. If peak-load oil and

TABLE 12-3

UTILITY OIL AND GAS CAPACITY AND FUEL USE
IN 1990 AND 1995[a/]

	Peak (.05)		Seasonal Peak (.25)		Intermediate (.50)		Baseload (.70)	
	(10^{15}) Btu	GW	(10^{15}) Btu	GW	(10^{15}) Btu	GW	(10^{15}) Btu	GW
1990								
Gas Turbine	0.197	32.2	0.019	0.6	0	0	0	0
Combined-Cycle	0.003	0.4	0.018	0.8	0	0	0.156	3.1
Oil/Gas Steam Turbine	0.141	21.5	0.857	38.0	1.72	40.9	0.821	14.4
Total Oil/Gas	0.341Q	54.1 GW	0.894Q	39.4 GW	1.72Q	40.9 GW	0.977	17.5 GW
1995								
Gas Turbine	0.224	36.6	0.032	1.0	0	0	0	0
Combined-Cycle	0.007	1.6	0	0	0.04	1.1	0	0
Oil/Gas Steam Turbine	0.175	26.7	0.932	41.3	1.27	30.3	0	0
Total Oil/Gas	0.406Q	64.9 GW	0.964Q	42.3 GW	1.31Q	31.4 GW	0	0

a/ Assumes:

Avg. Heat Rates	Peak (.05)	Seasonal Peak (.25)	Intermediate (.50)	Baseload (.70)
Gas Turbine	14,000	14,716	12,500	–
Combined-Cycle	15,000	10,000	8,600	8,200
Oil/Gas Steam	15,000	10,300	9,600	9,300

Source: ICF Coal and Electric Utility Model gas demand grew at the same pace over the 1995-2010 period as it did in the 1990-95 period, this liquid/gas market would be .49 quads in 2000 and .71 quads in 2010. This growth may, however, be overstated because load management should cut peak demand and considerable increases in the use of pumped storage could be realized.

The examples in Chapter 11 also showed liquids had some chance to capture a share of the seasonal peak demand served by existing oil and gas plants. In Table 12-3, the total seasonal peak market amounts to .894 quads in 1990 and .964 quads in 1995. Even if oil prices continue to rise, this market should remain strong, since it is technically difficult for coal plants to run at utilization rates below 20%. If seasonal peak demand grew at the same pace in the 1995-2010 period, it would be 1.039 quads in 2000 and 1.206 quads in 2010.

The baseload and intermediate-load markets for oil/gas steam turbine plants shown in Table 12-3 might best be viewed as temporary. Indeed, by 1995 the computer results show no baseload oil/gas plants at all. If economics prevails in later years, this market will continue to decline. It is unlikely that methanol facilities would be built to serve such an uncertain demand.

ENVIRONMENTAL REGULATIONS AND METHANOL

As discussed in Chapter 10, methanol may have some advantages over coal and other conventional fuels in terms of environmental performance. For this reason, methanol use may actually be encouraged by tighter environmental regulations. Three examples are as follows:

- Acid Rain Control: Methanol's zero emissions of SO_2 and low emission of NO_x may make it the preferred utility fuel for control of acid rain if a strong regulatory program is adopted by Congress. This is particularly true in the Northeast and Middle Atlantic areas.

- New Facilities in "Non-Attainment" Areas: Utilities wishing to expand facilities in an area which has not attained the national standards for SO_2, TSP, or NO_x may turn to methanol to avoid the need for costly "offsets" (i.e., emissions reductions in existing facilities). California and New York would be particularly good markets for methanol if this situation prevailed.

- Tighter New Source Performance Standards: If the EPA were to declare tighter emission standards for SO_2 or NO_x, methanol could become the prime fossil-fuel for new powerplants. This potentially represents the largest utility market for methanol, and could conceivably relace coal if the standards were set low enough. There is little likelihood in the short-run that such regulations would be proposed especially since coal plants can be made very clean (emissions can be cut to 2 lbs of SO_2 per MMBtu).