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COMPARATIVE EVALUATION OF SOLAR, FISSION, FUSION, AND FOSSIL ENERGY RESOURCES

PART IV

ENERGY FROM FOSSIL FUELS

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FOSSIL FUELS: SUPPLY AND DEMAND

Each year the average person consumes about 4.4 million BTU's (MBTU) of energy in the food he eats, which is the amount of energy contained in about 340 pounds of coal. This is the minimum amount of energy required to survive. Energy consumption today in some underdeveloped nations is not much greater than this value. However, in the United States today per capita energy consumption is about 390 MBTU's, equivalent to 15 tons of coal per person, a 90 fold increase over the energy consumption of primative man. As shown in figure 1, coal accounts

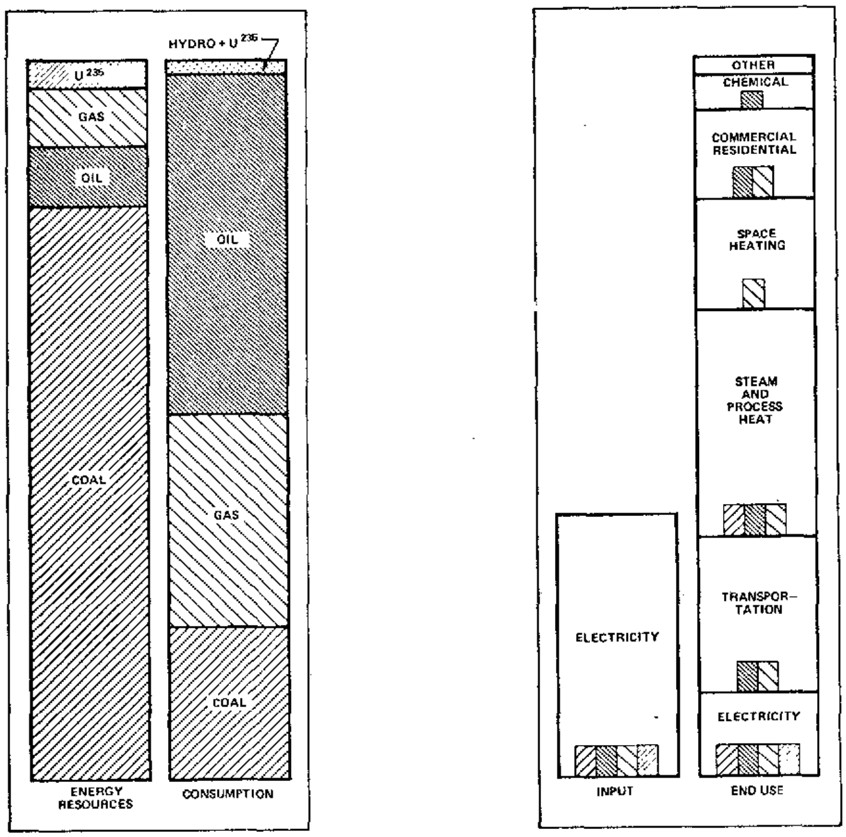

Figure 1. Comparison of Coal, Oil, Gas and U^{235} Resources and Uses[1]

for about 80% of the fossil fuel energy resources of the United States, gas about 10% and oil about 10%. However, gas and oil are being used much faster than coal. About 36% of these fossil fuels are used each year to generate electric power, which accounts for only 12% of our energy use, because of the energy lost as waste heat when fossil fuels are burned to produce electricity. Between 1900 and 1950, coal accounted for 65% of the fossil fuels used to generate electric power at central station plants. In 1971 this declined to 54%, and declined further with the enforcement of air pollution emission regulations prohibiting the combustion of high sulphur coal without expensive flue gas scrubbing equipment. However, the Arab oil embargo in 1973 and subsequent relaxation of air quality standards has caused this trend to reverse. States which permit the use of tall smokestacks for SO_2 control are continuing to rely heavily on high sulphur coal (up to 3% sulphur) for electric power generation[2], rather than use gas or fuel oil which are now much more expensive than coal.

Figure 2 illustrates the total world petroleum resources given in equivalent

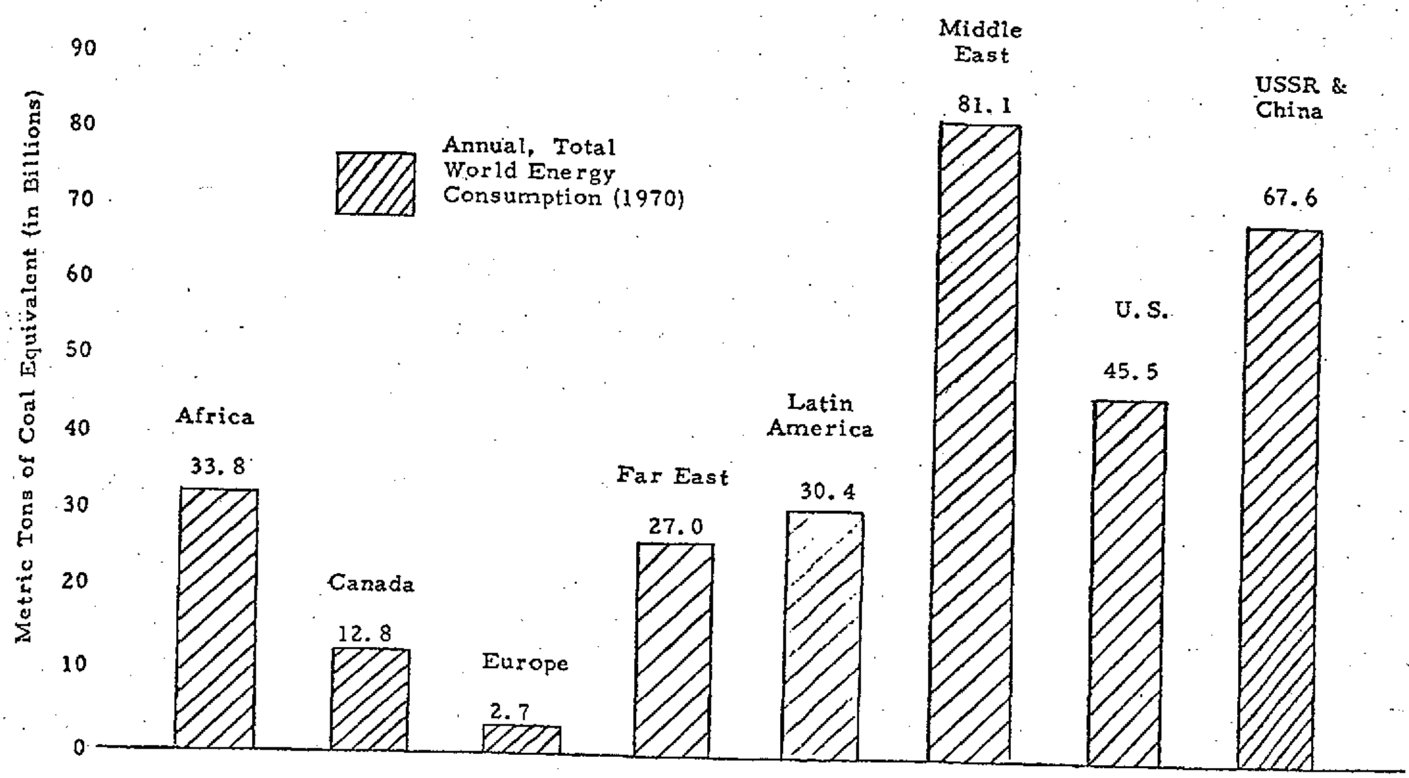

Figure 2. Total World Oil Resources[3]

metric tons of coal. Figure 3 gives the total world coal reserves. The total world reserves of oil is equivalent to 300 billion metric tons of coal, only about 4% of the total world reserves of coal which is given as 7637 billion metric tons. Figures for mainland China are very rough at present.

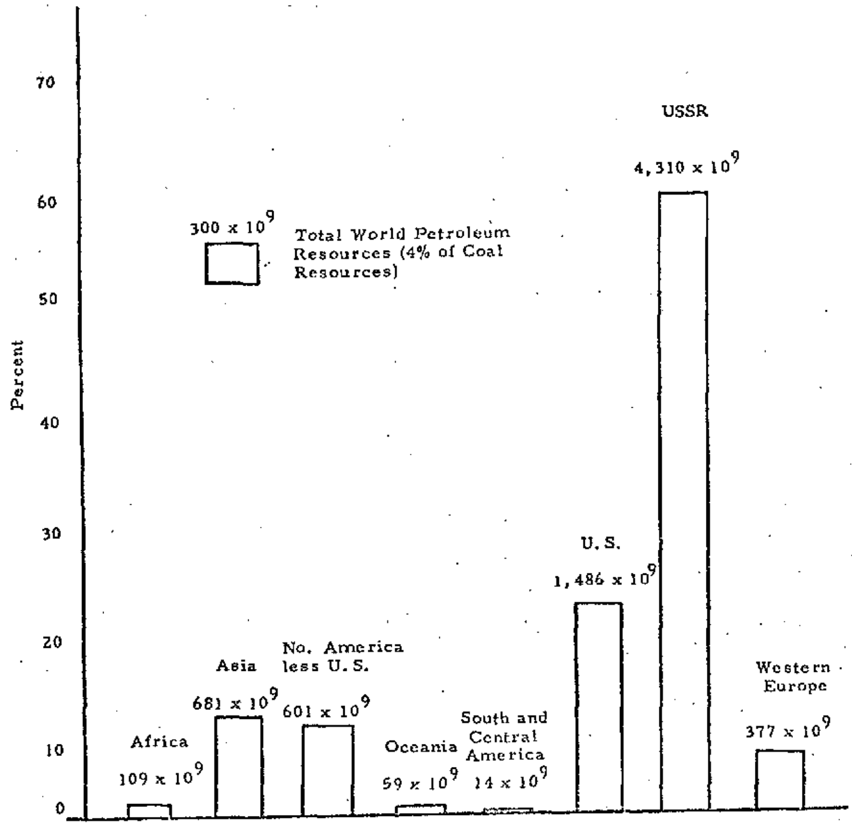

Figure 3. Total World Coal Resources[3]

The basis for the long term energy problem of the United States is illustrated by Table 1, which compares the United States annual consumption in 1970 with the proved recoverable fossil fuel reserves at that time[4]. Obviously, even at the 1970 rate of consumption, if the United States relied on domestic resources alone, the natural gas would be gone in 12 years and domestic oil would disappear in 7 years. However, these figures do not tell the whole story. The cost of

TABLE 1. Proved Recoverable Fossil Fuel Reserves and Annual Consumption - 1970

	Proved Reserves	U. S. Annual Consumption
Coal, U.S. (billion tons)	265	0.6
Gas, U.S. (trillion cu ft)	265	22.2
Oil (billion bbl)		
U.S.	37	5.5
Balance of free world	474	-
Communist bloc	100	-

extracting any of those resources increases as the resource becomes depleted, since the lowest cost deposits tend to be extracted first. Extraction cost is the big difference between the United States oil reserves (Figure 2) and the Mideast oil - extraction costs run about $0.25 per barrel in much of the Mideast as compared with several dollars per barrel in the United States.

Although the percentage of nuclear electric power generation is growing rapidly, the growth of nuclear power is not expected to reduce the demand for fossil fuels over the next two decades. Tables 2 and 4 illustrate projections by the Federal Power Commission made in 1970. The percentage of nuclear fuel use increases from 3% in 1970 to 55% in 1990 and the percentage of fossil drops from 97% to 45%, but the actual quantities of coal and oil use are expected to double. The main point here is that nulcear electric generation is not expected

Table 2. Projection of United States Generating Capacity[5]
(1 GW = 1000 Megawatts)

	1970		1980		1990	
	GW	%	GW	%	GW	%
Conventional Hydro	51.7	15.2	68	10.4	82	6.5
Pumped Storage Hydro	3.6	1.1	27	4	71	5.6
Fossil steam	260.3	76.5	393	59	557	44.6
Internal combustion and gas turbine	18.3	5.4	30	4.5	50	3.9
Nuclear	6.1	1.8	147	22.1	500	39.4
TOTAL	340.0	100.0	665	100.0	1260	100.0

Table 3. Electric Utility Power Generation-Thermal Generation by Types of Fuel[4]

	1920	1956	1960	1968	1969	1970
Coal	92%	70.8%	66.3%	61.9%	59.2%	58.0%
Gas	1%	21.7%	26.0%	27.6%	28.0%	28.0%
Oil	7%	7.5%	7.6%	9.4%	11.6%	12.0%
Nuclear	--	--	0.1%	1.1%	1.2%	2.0%

Table 4. Projected Fuel Use by Electric Utilities[5]

	1970		1980		1990	
	M TONS*	%	M TONS*	%	M TONS*	%
Coal	300.2	55	472.0	41.9	613.6	28.7
Gas	150.1	27.6	162.3	14.4	200.2	9.4
Oil	79.3	14.6	136.4	12.1	145.1	6.8
Nuclear	15.2	2.8	356.5	31.6	1176.1	55.1
TOTAL	544.8	100.0	1127.2	100.0	2135.0	100.0

*Fuel requirements here are expressed in equivalent tons of coal having a heating value of 25 million BTU/ton. M TONS = millions of tons.

to come in fast enough to reduce the consumption of coal, oil and gas for electric power generation. Of course, transportation, space heating, and industrial uses of energy are almost exclusively fossil fuels, especially oil and gas. Figure 8 of Part I of this report illustrates the switch from coal to fuel oil and gas for heating buildings. Our transportation systems rely almost exclusively on oil derivatives. Since the easily obtained domestic resources are gone and domestic reserves of oil and gas are rapidly running out (Table 1), the only alternative appears to be the importation of huge quantities of oil and liquified natural gas (LNG) from foreign countries.

Until very recently this appeared to be the solution to the energy problem. Since the Arabs were willing to sell us their oil at $1.80 per barrel, cheaper than we could extract it within the United States, continued supplies seemed assured. Japan and others built thriving economies on cheap foreign oil. However, economic pressures - the basic law of supply and demand - caused the price to rise to about $3.00/barrel, still a good price. Then came the Arab-Israel war of 1973 and the embargo and escalation of the price to over $11/barrel, twice the price of domestic crude in the United States. At this price, which threatens to go even higher, foreign oil is no longer the solution to the energy problem. Many projections have been made showing dramatic increases in oil imports to make up the deficit between domestic demand and domestic supply. These projections are pure fantesy. At today's prices, the United States simply cannot afford these imports. Such continued increases in imports are economically impossible. This is just as true for other western nations as it is for the United States.

With the rising price of oil and limited supplies of domestic gas and oil, the following approaches are being taken to reduce oil consumption and guarantee a continued gas supply.

1) Convert fossil-fired power plants now burning oil or gas to burn coal. Relax the air quality standards or use tall stacks to permit the combustion of high sulphur coal without causing the ambient air quality standards to be violated[2].

2) Develop coal-gassification processes to insure a continued supply of gas from coal.

Both of these measures increase the consumption of coal in order to reduce requirements for oil and natural gas.

The location of major crude oil producing areas, refining areas, and pipelines in the United States are illustrated in Figure 5. Figure 6 shows major natural gas producing areas and pipelines.

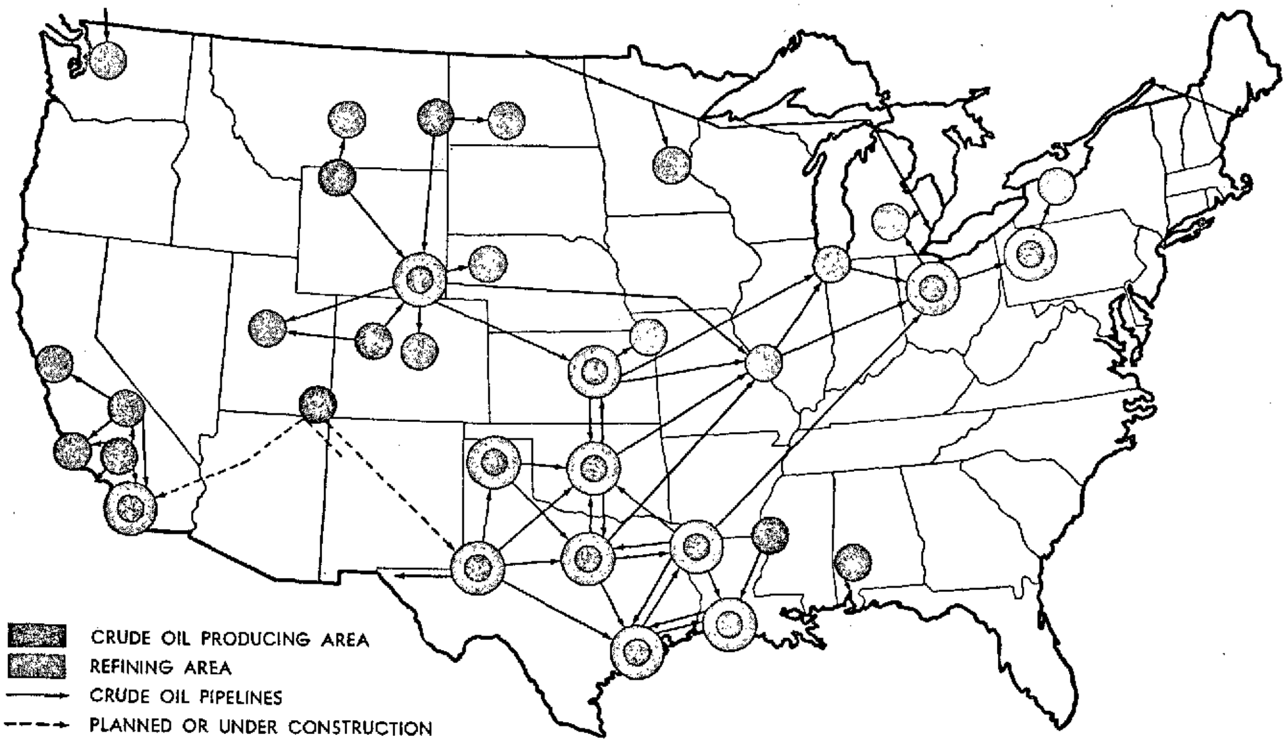

Figure 5. Oil Fields, Refining Areas and Pipelines in the United States[7]

Oil shale, a sedimentary rock containing organic matter, will yield oil when it is heated. Although the recovery of oil from shale has not been done on a commercial basis in the United States, it has been demonstrated on a small scale

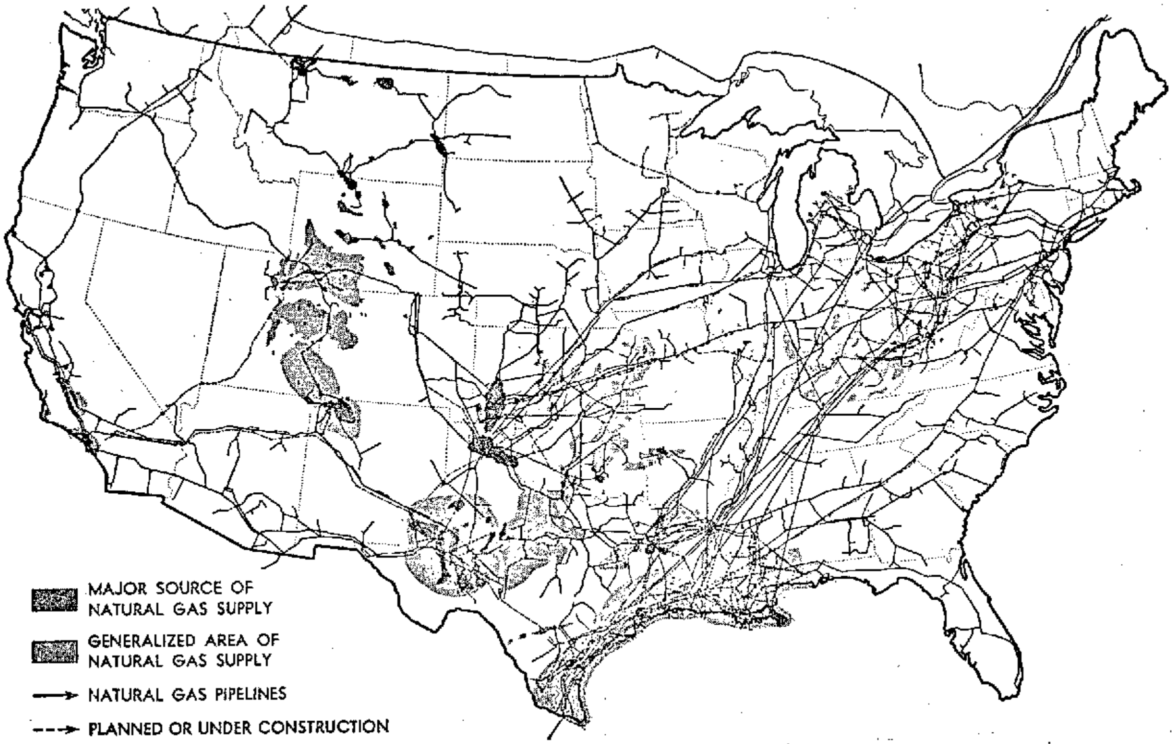

Figure 6. Natural Gas Fields and Pipelines in the United States[7]

that a range of acceptable fuel oils may be produced from shale oil by relatively simple refining techniques and that motor and diesel fuels can be produced by special refining methods. Since the yield of oil may be only 30 gallons per ton of shale, recovery of oil from this source involves handling large quantities of solid matter. The amount of domestic oil available from oil shale is about ten times the crude oil reserves in the United States[7], and greater than the oil reserves of the Mideast; however, the cost of extracting this oil is high and the environmental damage greater.

FOSSIL FIRED POWER PLANTS

Characteristics of New Plants

Schwieger[6] reported a survey of new fossil fired generating plants in 1971 and concluded that most new plants were operating with steam conditions above 2400 psi, 1000 °F (Figure 7). Turbine size and boiler capacity of the new plants

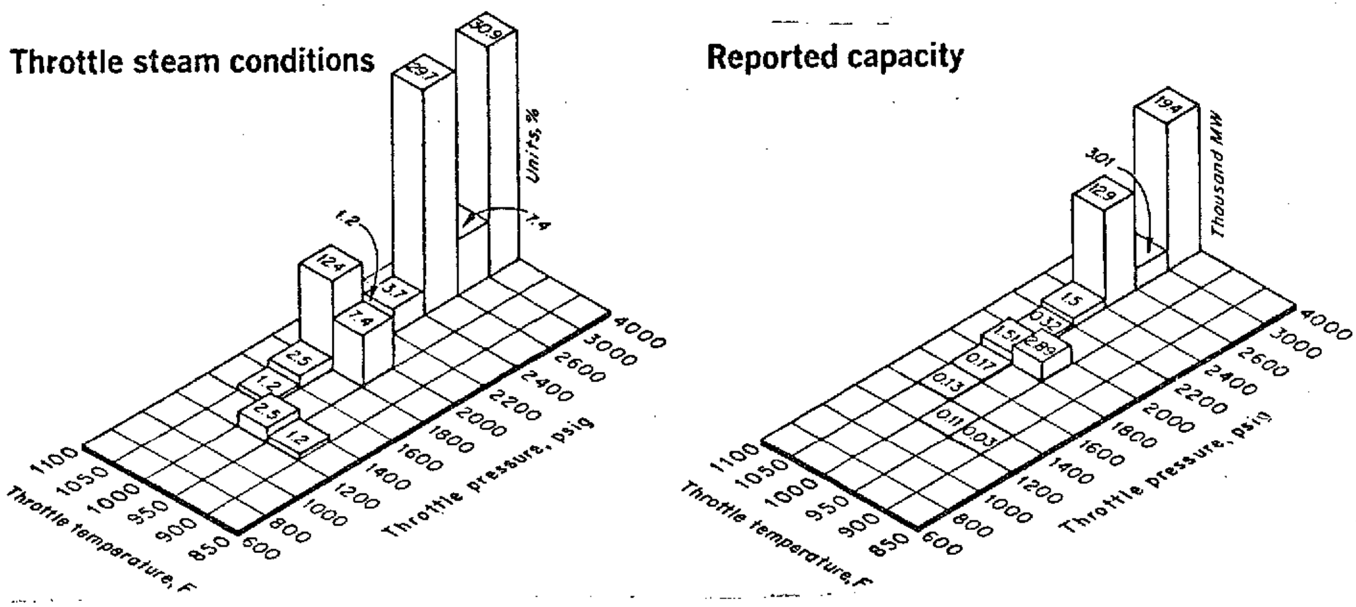

Figure 7. Steam Conditions of New Plants in 1971

are given in figure 8. Figure 9 shows the types of fuel used and other features of these new plants. The larger boilers use oil and gas.

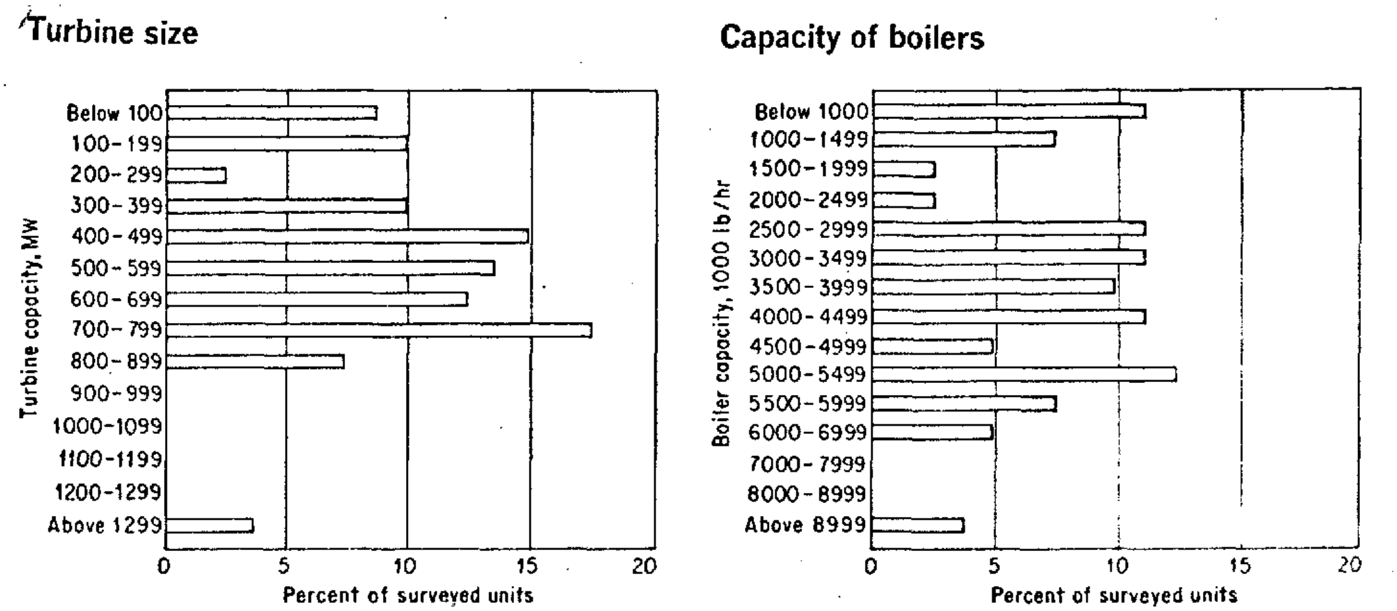

Figure 8. Turbine Capacity and Boiler Capacity of New Plants in 1971

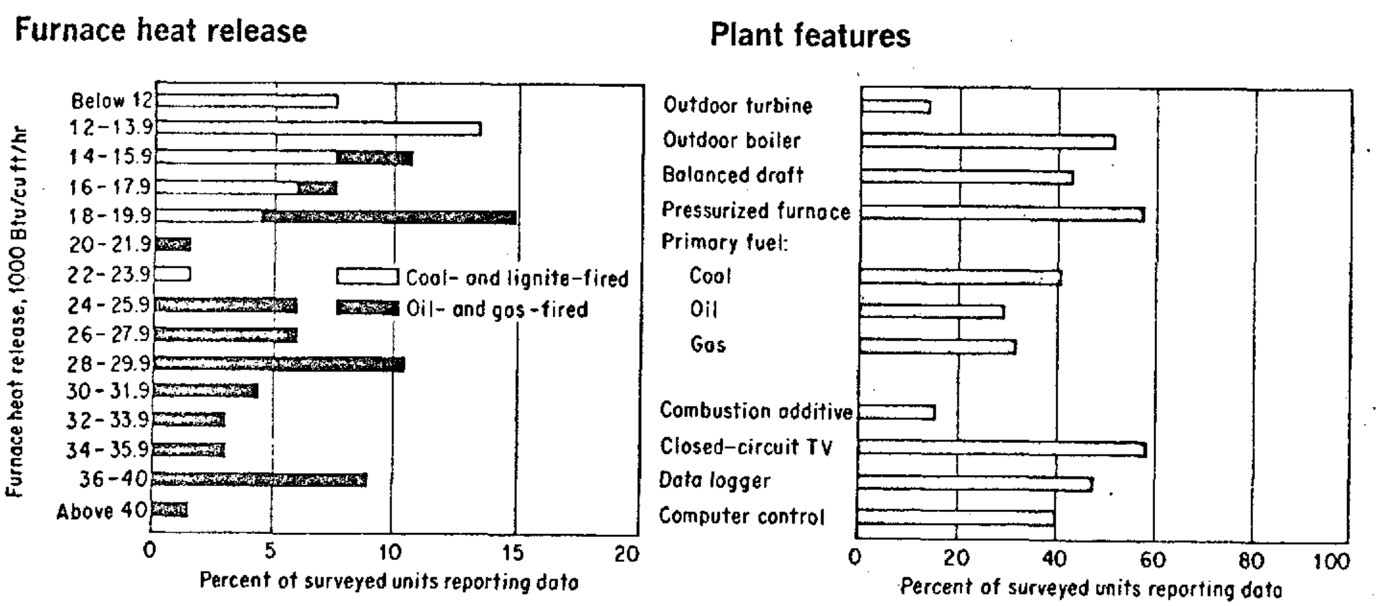

Figure 9. Heat Release, Fuels Used and Other Features of New Plants in 1971

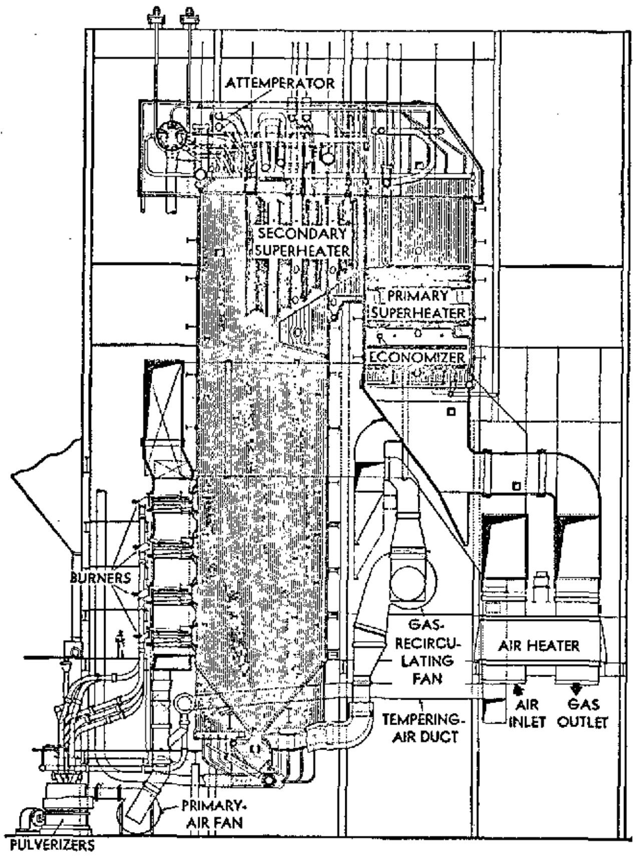

Figure 10. B&W Boiler for Providing 2.4 Million Lb/hr Steam at 2500 psi, 1050 ^{o}F with 1050 ^{o}F Reheat[7]

Technology

Figure 10 illustrates a modern fossil-fired boiler manufactured by Babcock and Wilcox, Inc.[7] Pulverized coal is blown into the furnace where combustion takes place. The wall of the furnace contains many boiler tubes; much of the heat of combustion is transferred to the water in the tubes, causing the water to boil to produce steam. The exhaust gases flow through the superheaters, then the economizer, then through the air heater, then through particulate (and perhaps SO_2) removal equipment, then up the stack. The air heater transfers heat from the exhaust gases to the air entering the furnace. In a well designed steam plant the exhaust gases may enter the stack at temperatures as low as 300^{o}F. The boiler in Figure 10 produces 2.4 million lb/hr of steam at 2500 psi and 1050 ^{o}F with reheat to 1050 ^{o}F[7].

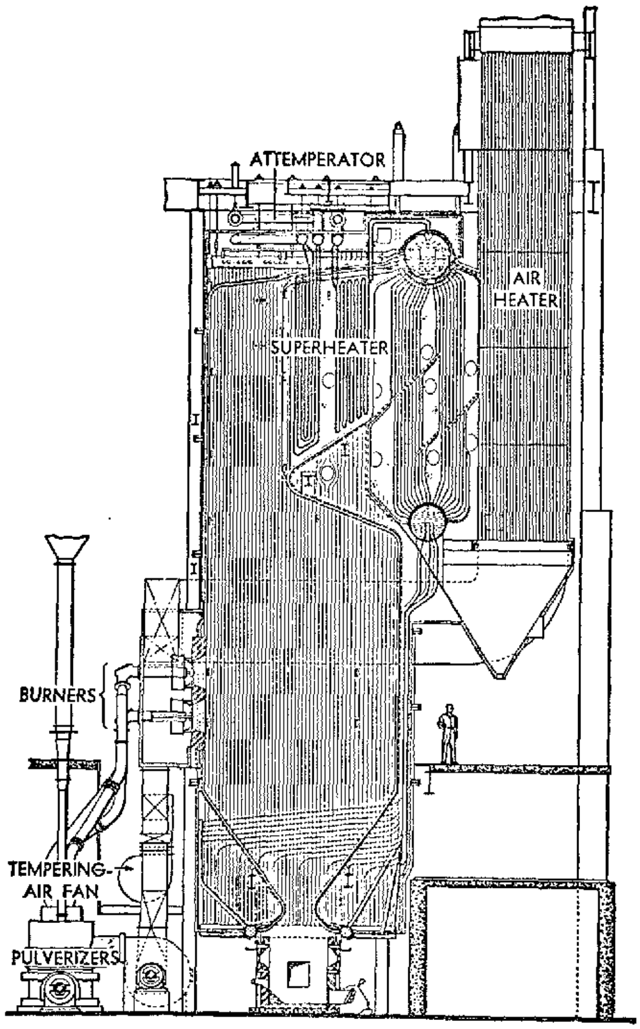

Figure 11. B&W Boiler (925 psi, 900 ^{o}F Steam)[7]

Figure 11 illustrates a smaller boiler for generating steam at lower temperatures and pressures.

A 4500 psi, 1150 ^{o}F steam supply system with two stages of reheat is shown in Figure 12. Few plants have been built operating at these steam conditions. This unit produced 120 MW_e.

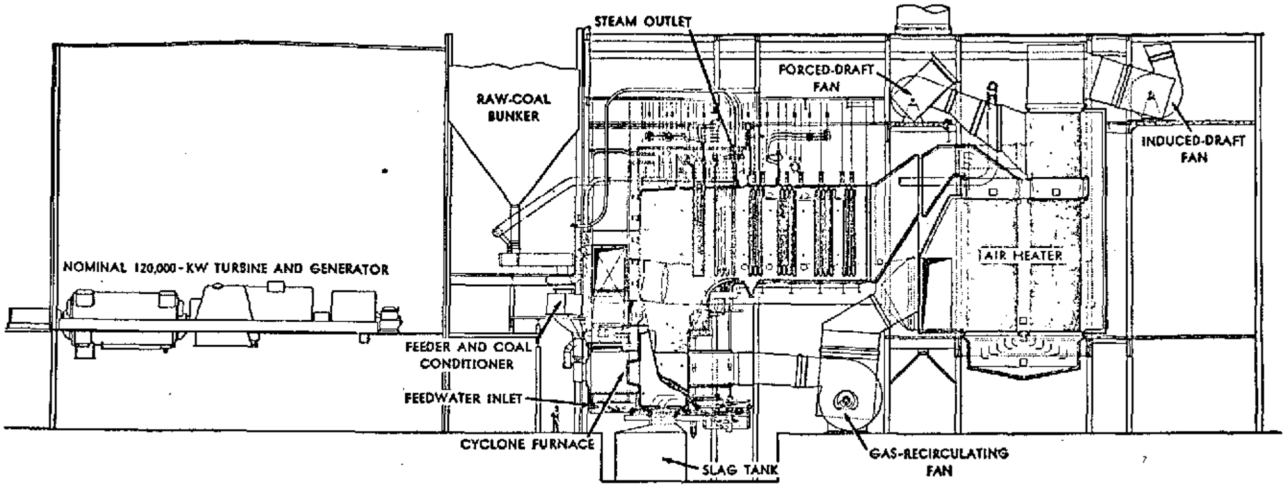

Figure 12. 120 MW_e Generating Unit with a B&W Boiler Operating at 4500 psi, 1150 °F with Reheats to 1050 °F and 1000 °F[7]

The fan circulates air or gas by means of a bladed rotor, or impeller, and a housing which collects and directs the gas discharged by the impeller. The power required by the fan is directly proportional to the volume of gas moved and the head (pressure difference) against which the gas is delivered, and inversely proportional to the efficiency of the fan and drive. Fans are used both for circulating air and gases in the plant and for blowing the exhaust up the stack. Stacks seldom provide the draft required by modern boilers, so fans are used to provide the required mass flow rate. Higher flow velocities up the stack also increase the plume rise, providing better dispersion of the effluent in the atmosphere.

There are basically two types of fans; the centrifugal fan (Figure 13) and the axial flow fan (Figure 14). The centrifugal fan accelerates gas radially outward by a rotor to a surrounding scroll casing. The axial flow fan accelerates the gas parallel to the fan axis.

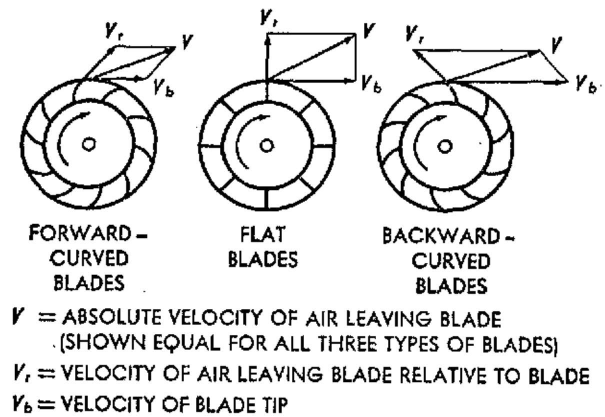

Figure 13. Three General Types of Centrifugal Fans[7]

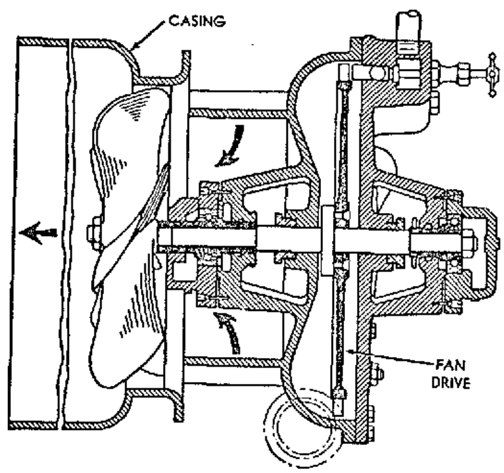

Figure 14. Simple Type of Axial Flow Fan[7]

Several techniques are used to vary the fan speed including magnetic coupling, hydraulic coupling, mechanical drive systems, variable speed d.c. motors, and variable speed steam turbines. The magnetic coupling uses two windings; a change in field strength between them carries the slip and the speed of the fan. Similarly, the hydraulic coupling (Figure 15) uses a variable thickness of oil to provide for variable slip.

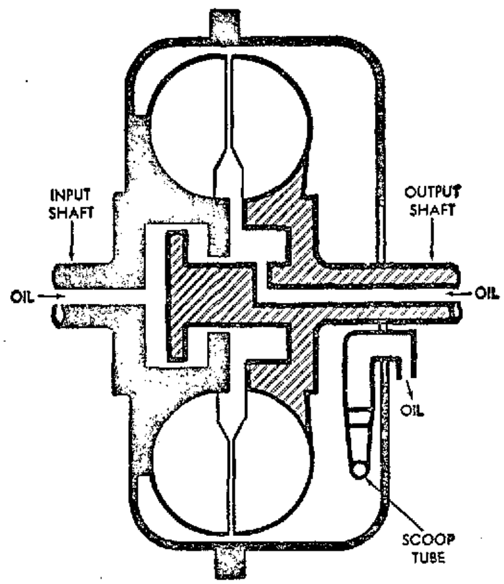

Figure 15. Hydraulic Coupling for Varying Fan Speed with Constant Speed Driver[7]

Two-speed AC motors are also used in connection with variable coupling devices to vary fan speed with minimal efficiency loss.

For higher pressure differentials centrifugal compressors can be used, of the type shown in Figure 16.

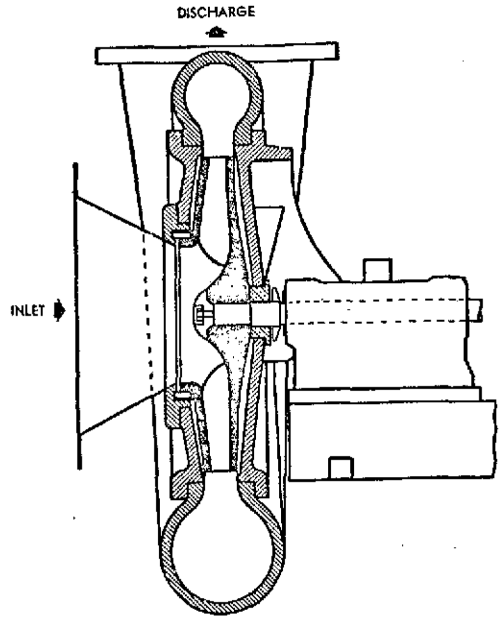

Figure 16. Centrifugal Compressor

The flow of gases through a down-fired boiler is shown in Figure 17. The combustion gases in the furnace are much hotter than the water in the boiler tubes; this large temperature difference is necessary for the high heat transfer rate in the boiler. The exhaust gas is somewhat cooler when it enters the superheater, but still several hundred degrees hotter than the peak steam temperature.

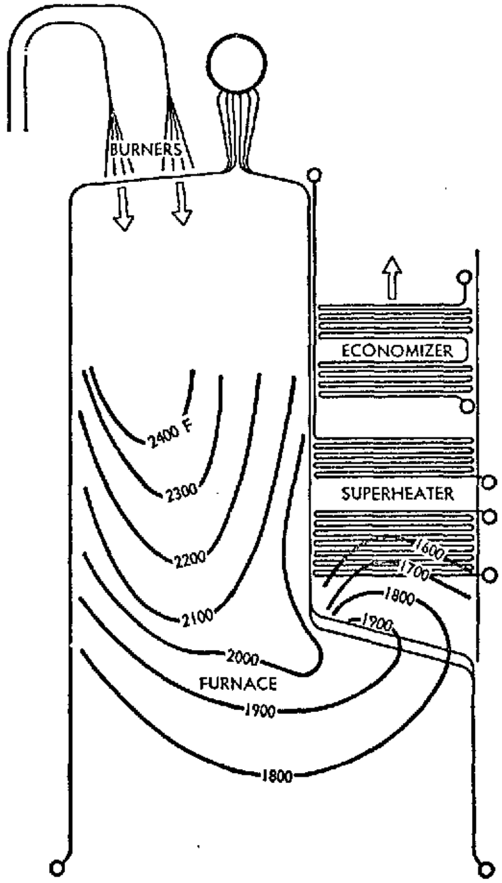

Figure 17. Temperature Profile of Combustion Gases in Down-Fired Boiler[7]

Air heaters transfer heat from the products of combustion to the air entering the furnace, so that this heat is recovered and the plant efficiency is increased. Tubular air heaters consist of a nest of straight tubes expanded into tube sheets and enclosed in a steel casing. The tubes are rolled into tube sheets at both ends with one sheet free to move to provide for expansion. The tubes are typically 2 to 2-1/2 inches in diameter. Five types of tubular air heaters are illustrated by Figure 18.

Another type of air heater, called the rotary regenerative air heater, uses slightly separated metal plates supported on a slowly rotating shaft. As the plates pass through the exhaust gas stream they are heated and then in passing

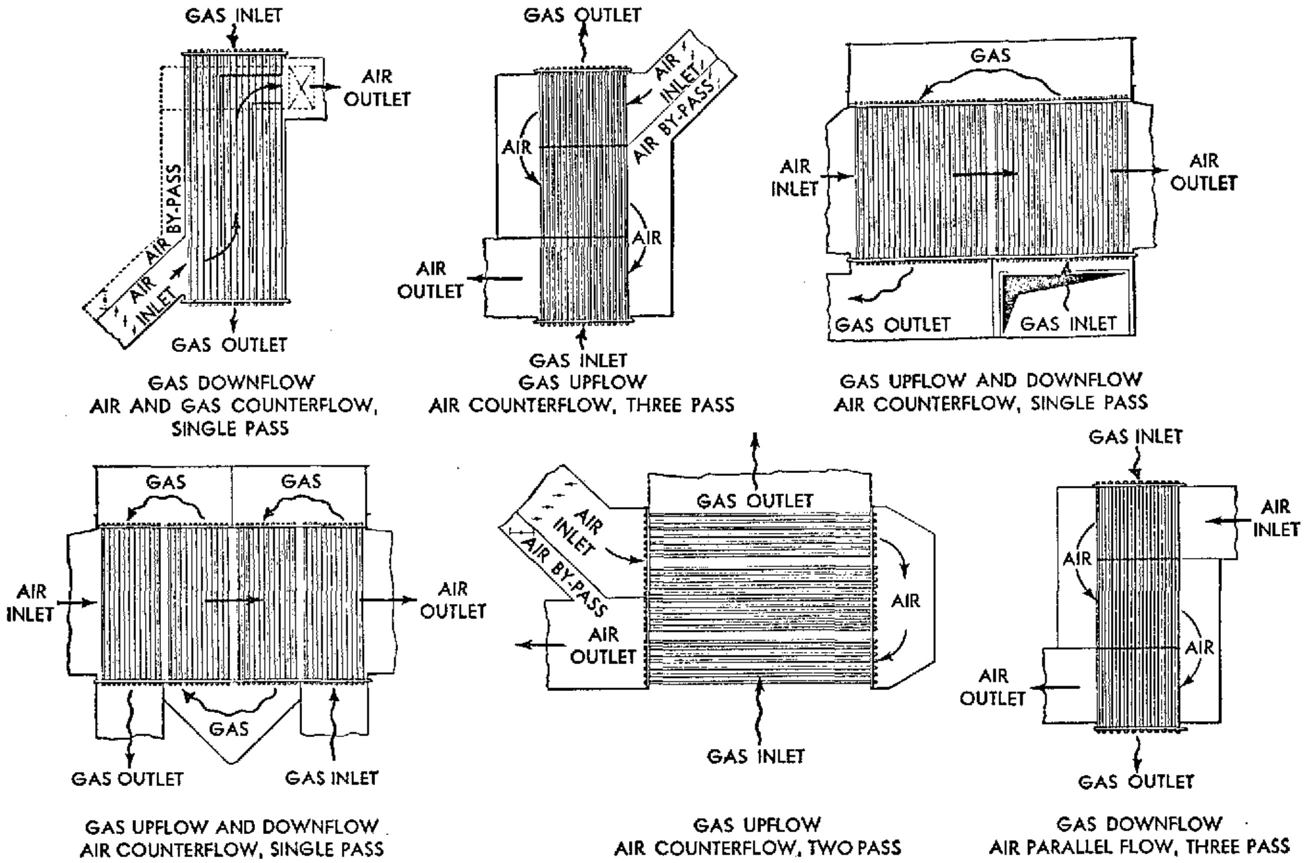

Figure 18. Five Types of Tubular Air Heaters

through the air stream they give up heat to the air before reentering the exhaust gas stream.

At the present time there appears to be no significant economic incentive to increase steam temperature beyond 1050 ^{o}F, so the most widely used steam conditions today for coal and oil burning plants are in the range of 1800-3500 psi with an initial temperature of 1000-1050 ^{o}F and single-stage reheat to 1000-1050 ^{o}F. One stage and, in a few cases, two stages of reheat are employed with a maximum temperature of 1050 ^{o}F[8].

Costs

Based on data from 42 modern power plants of 34,808 MW_e total generating capacity, the average capital cost for this fossil-fired generating capacity was

$123/$KW_e$, the average load factor was 62.8%, and the average thermal efficiency was 34%. The total operating cost in 1970 averaged 3.48 mills/kw hr. These generating costs ranged from 2.16 mills/kw hr. for a large multi-unit station burning 21.6¢/million BTU gas to 6.73 mills/kw hr. for a smaller unit burning 41.8¢/million BTU coal[9]. Figure 19 illustrates the operating cost and capital cost of these fossil fired power plants. As is seen from the chart on operating costs, the cost of fuel accounts for the largest part of the operating cost of the plant. These fuel costs have risen sharply since 1970. In addition, costs of building plants have increased due to inflation.

In 1971 the annual rate of increase of construction costs was more than 12%, primarily due to the 17% increase in construction labor cost that year. This increase was due both to wage rate increases and productivity decreases. As reported by Roe[10] in 1972, "When both wages and fringe benefits are considered, workers in the construction industry today earn on the average between $6 and $10 per hour. Many of these workers also earn overtime. For example, for a 45-hour work week, many of the higher skilled trades such as steam-fitters and boilermakers today can earn a gross pay of $550 to $600 per week, or around $30,000 per year.

"Another factor of importance is a wide variation in construction wage rates throughout various areas of the country. Laborers' hourly wages vary from $4.40 in New Orleans to $8.81 in New York. Steamfitters' hourly wages vary from $8.40 in Denver to $11.54 in Los Angeles.

"Another significant contributor to increasing construction labor costs is a decline in productivity. Overall statistics for the construction industry indicate that output per man-hour increased approximately 1-1/2% per year during the twenty-

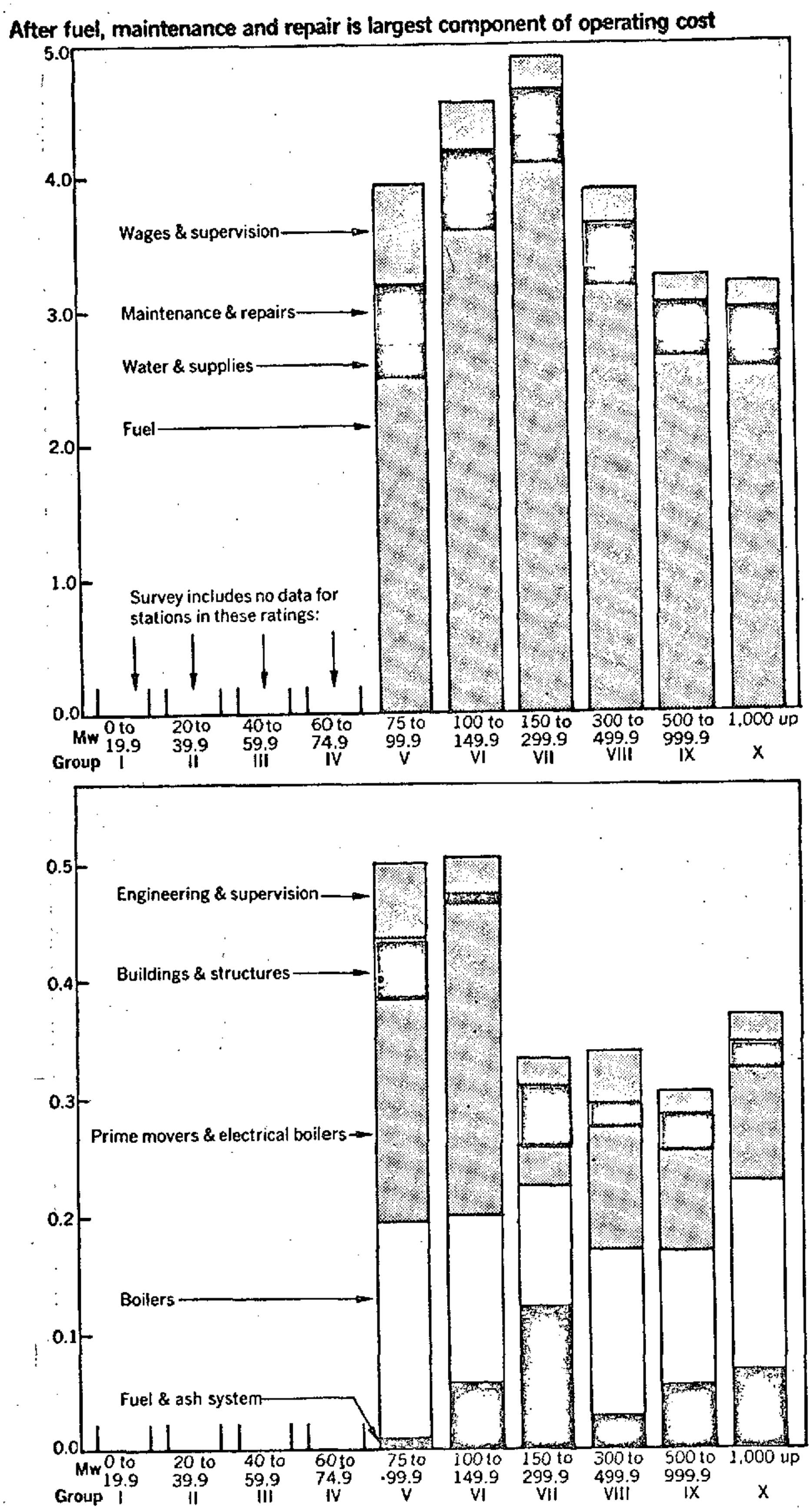

Figure 19. 1970 Operating and Captial Costs of Fossil Plants[9]

year period between 1947 and 1967. This rate of increase was well below that of most other industries. Careful examination shows that this output increased through advances in equipment technology and use, not through increased labor productivity. The rate of overall productivity improvement in this country declined in the late 1960s. There appears to be clear evidence that productivity has actually decreased a great deal in the construction industry.

"On many power plant construction projects today, the trend has been toward very liberal use of overtime to try to meet schedules and to provide incentives to attract labor to a particular project work location. The use of overtime can add tens of millions of dollars to the cost of a generating plant, frequently with questionable long-term improvement in schedule. A study of the use of overtime in the construction industry was performed for the Construction Users Anti-Inflation Round Table. It was found that a 50-hour work week over periods of four to six months boosted labor costs 50% while producing little if any extra output. Therefore, overtime should be resorted to only where there is no alternative.

"In recent years, equipment and material costs, which have traditionally comprised up to 60% - 80% of power plant construction costs, have generally increased at rates of 4% - 10% per year. The increases occurred for a number of reasons such as wage increases, increased quality requirements, and higher interest rates."

Other factors increasing costs are schedule delays, and new requirements for pollution control equipment which can add $50 million or more to the cost of a fossil plant. Roe[10] expects the capital cost of fossil-fired plants to rise as high as $\$400/KW_e$ by 1980.

GAS TURBINES

The electric utility industry is now using gas turbines extensively because they can be installed quickly to provide needed capacity. The new larger gas turbines of more than 50 MW_e rating, with their improved efficiency, are proving valuable for peaking service. The basic characteristics of short shipment cycle and low installed cost has been crucial to customers suffering from low peak load forecasts, long nuclear delays, or poor reliability of new large units.

Two types of mid-range gas turbine plants are the regenerative cycle gas turbine, and the combined cycle STAG (acronymn meaning Steam and Gas) plant. Each has its own unique advantages for specific utility systems.

Until recently, there was little industry interest in mid-range generation. The typical utility load duration curve was essentially supplied according to the age of the power sources. The latest large plants having the best efficiency supplied the base service at load factors of 80-90 percent. The middle part of the curve was covered by older plants with poorer heat rates at load factors of 20-80 percent. Plants for peaking duty were the very oldest steam plants with 12,000 to 20,000 BTU/Kw hr heat rate. This system has worked for quite some time, as the plants being ordered were basically much better versions of the same type of power source - fossil steam turbines. Sizes continued to increase and heat rates continued to decrease.

Recent changes, however, have forced changes in this approach. Rather than continuing to buy the same type of plant, utilities have seen the value in very large nuclear and fossil steam plants for economical base load generation. At the same time peaking requirements have sharply increased to meet escalating peak load trends, combined with decreasing system load factors. No longer does a system's oldest units have either the characteristics or the total power to supply this peak load. Recently large numbers of gas turbines have been ordered to supply this need. Thus recent history has tended to divide power systems into two separate power sources, gas turbines and very large base load units, each ideally suited to its special purpose. In between these two lies mid-range service. As before, the older fossil units are supposed to fill this need. But present day needs are making this service difficult. The absolute size of the most modern base load units places added emphasis on mid-range units during scheduled maintenance outages. Unfortunately, lower availability of the large plants has increased each system's total mid-range power requirement. At the very time these older units are being asked to shoulder this added burden, with their inherent characteristics of poor load swing capability, long starting and stopping cycles, and poor part load performance, they are being hardest hit for their air pollution. For the future, these fossil units must continue to operate until they reach retirement age. But they must be supplemented now, and replaced later, by power plants intended for mid-range service.

Regenerative Gas Turbines

The regenerative cycle gas turbine is essentially a simple cycle gas turbine modified to make more efficient use of the available energy. It accomplishes this by using the heat of the turbine exhaust to preheat the air leaving the compressor just before it enters the combustion chambers. This preheating, of course, reduces the amount of fuel required to raise the air temperature to the desired turbine inlet temperature. The reduction in fuel consumption lowers the plant heat rate by over 2000 BTU while reducing the net plant power output only slightly. Table 5 lists the output and heat rate for simple cycle and regenerative cycle machines operating on three different fuels: gas, distillate, and residual oil.

TABLE 5

CYCLE	FUEL	NET OUTPUT (KW) BASE	NET OUTPUT (KW) PEAK	NET HEAT RATE (BTU/KW-HR) (HHV) BASE	NET HEAT RATE (BTU/KW-HR) (HHV) PEAK
Simple	Gas	45,800	53,300	13,460	13,220
	Distillate	44,800	52,100	12,980	12,790
	Residual	40,800	45,900	12,800	12,500
Regenerative	Gas	44,800	50,400	11,100	10,640
	Distillate	44,000	49,500	10,720	10,270
	Residual	38,800	43,500	11,200	10,670

The regenerative cycle gas turbine, then, is basically a significantly more efficient machine than the simple cycle, and accomplishes this without sacrificing any of the simple cycle units' advantages. Except for the additional air piping, it is the same compact, packaged unit. It thus has a short shipment schedule, minimal installation labor, and short installation time to cut down interest-during-construction costs. Combining its small land area requirement with the latest advances in both air pollution control (no visible smoke) and acoustic design will allow optimum utilization of this unit's self-sufficiency to reduce transmission costs. This plant is completely independent, requiring no cooling water or auxiliaries and is capable of remote operation and black starting. Remote unattended operation, no water, no smoke, and minimum space requirements, and esthetic appearance, allow properties such as substations and existing plant sites to be used. This can result in significant savings in site development and transmission costs.

Since the regenerative cycle machine uses the standard simple cycle unit as a base, and adds a time-tested regenerative unit with no untried developmental problems, it has high availability. It makes no compromises on the simple-cycle unit's fast, low-cost starting ability. The unit provides good part-load performance by using variable inlet guide vanes designed to reduce the air flow at part load in order to maintain a constant exhaust temperature, thus allowing a constant efficiency down to 83% load. This feature actually results in almost a 1000 BTU additional heat rate improvement for loads below 83% over the simple cycle performance.

The modular construction of the regenerative cycle design allows great latitude in plant size flexibility, both in the definition of initial plant size, and in the capability for future additions. The 50,000 KW range unit size permits load carrying flexibility, spinning reserve capability, and low reserve margin requirements unattainable by large fossil plants, while forcing no limitation on maximum plant size.

The regenerator itself is a very simple component, with no moving parts. The regenerator is built in two sections, one on each side of the gas turbine. The gas turbine exhaust splits and flows through the regenerator after which it is turned upward and discharges to the atmosphere. By splitting the regenerator in two sections the piping is symmetrical and the top half of the turbine can be removed without disturbing the regenerator piping.

The air from the compressor passes through an integral manifold system into a number of tubes. This air passing through the tubes is heated by exhaust gases flowing on either side of the air channels in the opposite direction. The air is then collected in a second manifold and discharged to the outlet piping where it is then conducted to the combustion chambers.

The regenerator is of bar and plate construction. This design allows maximum utilization of the available heat transfer surface and results in a compact unit. An exhaust gas tube consists of a copper brazed and welded envelope with internal corrugated extended surface. Copper brazing the extended surface to the tube sheets results in a thermal bond of maximum heat conduction. Structural reliability is assured by preloading the bond in compression.

A tube bank consists of a number of these tubes, separated by spacers, and welded to form an integral unit. The passages for the compressor air are thus formed by the spacers between the exhaust gas tubes. The regenerator assembly is completed by manifolding the number of tube banks required for the rated air flow.

Combined Cycle

Higher efficiency is achieved by effective use of the energy wasted in the form of heat in the exhaust. The regenerative cycle unit uses this heat to raise the temperature of the compressor air. In the steam and gas turbine STAG plant the exhaust is used to make steam in a heat recovery boiler. This steam then drives a steam turbine. Table 6 lists parameters for two plants sold by the General Electric Company.

TABLE 6

PARAMETERS OF TWO STAG PLANTS

PLANT	FUEL	(KW) BASE	PEAK	NET HEAT RATE (BTU/KW-HR) (HHV) BASE	PEAK
STAG 330	gas	307,300	336,700	9110	8760
	distillate	303,400	331,800	8750	8430
	residual	286,300	306,200	9080	8750
STAG 180	gas	168,000	182,700	9100	8850
	distillate	165,900	180,200	8790	8570
	residual	159,500	167,500	9140	8850

To the gas tubines are attached heat recovery boilers. A bypass stack and damper are provided between gas turbine and boiler to allow peaking operation of any or all gas turbines apart from the rest of the system. All dampers, boiler controls, supplementary firing burner controls, and retractable soot blower controls (if needed), as well as controls for the gas turbines and steam turbine, are remotely located in a central control house.

The steam turbine for the STAG 330 is a GE tandem compound, double flow, non-reheat steam turbine with 23 inch last stage buckets. Again, in steam turbine design, packaging and standardization play key roles. For example, the downward exhaust has been replaced by side exhausts to twin condensers. As a result, the turbine can be factory assembled and shipped complete. The condenser elements can be factory tubed and shipped completely assembled.

The balance-of-plant electrical and mechanical hardware is also arranged in a manner allowing for minimum installation cost while still providing the necessary operational flexiblity. For example, provisions are included for dual sources of auxiliary power: one from the station bus and one from a separate outside source. The plant output is available through three separate step-up transformers and associated circuit breakers, one for each pair of gas turbine generators and one for the steam turbine generator. The mechanical accessories include two half-sized boiler feed pumps, two half-sized circulating water pumps, two full capacity condensate pumps and a steam bypass arrangement for plant startup.

Control of the STAG plant is designed for optimum mid-range operation. Most efficient operation requires control between the maximum output points for different numbers of gas turbines in operation. This plant is controlled as a single power source, not as a combination of five different sources, for mid-range service. Two men operate the plant from a master station control console located in a central control house. (Use of a high-salt, high-metal residual fuel would require an additional man for the fuel analysis, washing, treating, and transfer system.) Maximum automation has been incorporated in all start-up and load change sequences. A load change is actuated by the operator through a manual movement of a single load selector.

The STAG plant, then, is quite different than the regenerative cycle plant, yet offers advantages for mid-range operation. It has a low heat rate (high efficiency) rivaling fossil steam plants in its size range. The package concept using tried and proven components assures high availability. The plant is designed for fast starting. After a 12 hour shutdown, the plant can be brought to full load in 45 minutes. Even in a completely cold start, more than half the rated output can be available within 20 minutes, with full load in 150 minutes. Plant control design assures excellent part load performance.

The plant is designed to require a minimum number of operators: one at the control console, and one roving inspector (unless one man is needed for fuel treatment).

STAG can be in commercial operation two years from the placement of an order. Due to maximum packaging, installation time is less than six months after the arrival of the major equipment at the site.

The plant has complete black start capability. Water requirements are only 40% of those for a similarly rated fossil steam plant. This feature, plus the no-smoke combustion in the gas turbines assure minimal air and water pollution.

While the overall plant control has been emphasized, the composition of the plant allows peak load pick-up by operating any number of the gas turbines alone - an important feature.

Each of the mid-range plants discussed above has its own unique advantages. They are completely different concepts in mid-range plant design. The optimum plant selection for a specific time in a specific utility system requires the analysis of a number of economic questions. These are reviewed below.

Costs

The mid-range plants that have been discussed have their own characteristics which will be reflected in their long-term costs. Any analysis of the costs of alternative power plants must be based on several major assumptions. The need for a given plant is a function of the entire generation presently in operation on a system. All alternative plants must be judged on the same type of operation and load factor.

The costs given here included the cost of the basic plant and required options. To this is added installation costs, cooling water costs where required, fuel treatment costs where necessary, and interest during construction. A capitalization rate of 15% was assumed. Neither transmission costs nor system reserve differentials were included. These could vary substantially between systems. Fuel storage costs and system electrical equipment beyond the 13.8 KV breaker were not included, but are essentially equal for all machines. All costs are for mid-1972 commerical operation.

The installed costs for the simple cycle, regenerative, and STAG units for three fuels are shown in Table 7.

TABLE 7

PLANT INSTALLED COST

($/KW AT PEAK RATED NET OUTPUT)

	Gas	Distillate	Residual
Simple Cycle	85	87	107
Regenerative Cycle	105	107	130
STAG	119	121	135

Operating costs for these machines include fuel cost, labor, and maintenance. For this evaluation fuel costs of $\$.40/10^6$ BTU for natural gas, $\$.80/10^6$ BTU for #2 distillate oil, and $\$.40/10^6$ BTU for residual oil were used. No operators were assumed for gas or distillate fuels for the simple and regenerative cycle machines, and one man to handle fuel treatment equipment for residual oil. Two operators are needed for the basic STAG unit, plus one additional for fuel treatment of residual oil. Maintenance costs can be accurately estimated based on 20 million hours of gas turbine operating experience.

For natural gas, the simple cycle unit is most economical at low operating hours. The regenerative and STAG machines do not better the simple cycle unit until almost 3500 hours per year. In the mid-range area, between 2000 and 5000 hours, the differences between utility systems could favor any of the three machines. With the distillate oil, which is twice as expensive as gas, the breakeven point is at one half the gas breakeven time. The very efficient STAG unit is the clear favorite for long operation, unless cooling water or transmission limitations are governing.

For residual oil, the breakeven point is at 2000 hours, with the regenerative unit significantly poorer than STAG. This difference is largely a function of the proportionately higher fuel treatment costs for the regenerative unit.

The differences that can result from individual utility requirements must be emphasized. Each system should be evaluated separately.

The rapid increase in gas turbine purchases is illustrated by Table 8.

TABLE 8

UNITED STATES PUBLIC POWER SYSTEMS PLANT ADDITIONS AND IMPROVEMENT

Type of Generation	$ Expenditures (millions) 1970	1971
Fossil-Steam	305	321
Gas Turbine	18	59
I.C. Engine	19	36
Hydro	85	80
Nuclear	204	299

Projections to 1980 indicate that it is possible that 6 to 10% of the total 600,000 MW_e capacity could be fossil fired gas turbines.

In the 1971-72 period the installed costs ranged from about \$60/KW_e to about \$85/KW_e for simple gas turbines, to \$105/KW_e for 50 MW_e regenerative plants, to \$125/KW_e for 330 MW_e combined cycle (STAG) plants[11].

COAL GASIFICATION

The manufacture of both substitute natural gas (SNG) and low-Btu gas from coal has become a subject of increasing interest in recent years-SNG because of the decline in natural-gas reserves and low-Btu gas because of the potential demand for clean fuel gas to meet environmental goals in the generation of electric power. Many coal-gasification processes have been used in the past to generate low-Btu producer gas or water gas. These processes generally operate at atmospheric pressure and do not represent economically feasible routes to high-Btu gas. The only commercially available high-pressure process for coal gasification is the Lurgi process. The commerical use of the Lurgi process that comes closest to SNG manufacture is that in which town gas, which has a heating value of 400 to 450 Btu/scf, is produced. One such installation is at the Westfield plant of the Scottish Gas Board[12]. There are numerous other coal-gasification processes being developed today. Most of the more widely known developments are being sponsored by the U. S. government or by government-industry groups.

Table 9 lists the major coal gasification processes. There are three basic steps in each of these processes: local preparation, gasification, and raw gas upgrading. The preparation phase includes handling, storage and size reduction of the coal. Some processes also require air oxidation of the coal in a fluidized bed at 600 to 800 ^{o}F and low pressure to drive off some of the volatile matter and render it nonagglomerating for the gasification process. The gasification step includes the chemical reactions which produce gas; these reactions are about the

TABLE 9

SUMMARY OF BETTER-KNOWN COAL GASIFICATION PROCESSES[13]

PROCESS NAME	DEVELOPER	Heat Input	Pressure, psig	Reactor type	Status
Lurgi	Lurgi	oxygen	300-500	downward moving-bed	near demonstrated
HYGAS oxygen	IGT	oxygen	1000-1500	fluidized	80-ton/day P.P. constructed
BI-GAS	BCR	oxygen	1000-1500	entrained/ slagging	will build 120-ton/day P.P.
Synthane	BOM	oxygen	600-1000	entrained/ slagging	will build 70-ton/day P.P.
Kellogg	Kellogg	O_2/air	400-1200	molten salt	have bench-scale data
CO_2-acceptor	Consol	air	150-300	fluidized (dolomite)	40-ton/day P.P. constructed
COGAS	FMC	air	50-200	entrained/ fluidized/ slagging	have bench-scale data
HYGAS electrothermal	IGT	electrical	1000-1500	fluidized	80-ton/day P.P. constructed

same for all the different processes. However, there are important differences in the method of feeding coal to the reactor system, in the reactor configuration itself, and in the method of supplying the heat needed for the gasification reactions. For simplicity, only four basic reactions are shown.

$$\text{coal} + H_2 \rightarrow CH_4 + C \qquad (1)$$

$$C + 2H_2 \rightarrow CH_4 \qquad (2)$$

$$C + H_2O \rightarrow CO + H_2 \qquad (3)$$

$$C + O_2 \rightarrow CO_2 \qquad (4)$$

First, the coal pyrolyzes, and much of the volatile matter is cracked and hydrogasified to methane and smaller quantities of higher hydrocarbons. Second, some of the char that remains can react with hydrogen to form additional methane. This reaction is very exothermic, but for most of the processes currently under development, the extent of reaction 2 is not sufficient to balance the very endothermic heat of reaction 3. In reaction 3, steam is the gasifying agent for the carbon, and the products are carbon monoxide, hydrogen, and smaller quantities of carbon dioxide. From a material-balance standpoint, reaction 3 is necessary because the coal is deficient in hydrogen (relative to the hydrogen content of methane); the additional hydrogen is supplied from water through the steam-carbon reaction. In almost all cases, the necessary heat input to the system is achieved via reaction 4 in which char is reacted with either oxygen or air to produce carbon dioxide or carbon monoxide. When air is used, the nitrogen-containing flue gases must be prevented from mixing with the raw gas produced in the gasification reactors.

The raw gas has a higher heating value of about 300 to 500 Btu/scf (dry basis). This gas contains methane, carbon monoxide, hydrogen, carbon dioxide, hydrogen sulfide, ammonia, and unconverted steam. The raw gas is upgraded to SNG in a series of steps common to almost all the processes. In shift conversion, the carbon monoxide-to-hydrogen ratio is adjusted for the later methanation step by reacting some of the carbon monoxide with steam to produce hydrogen and carbon dioxide. A second step is the removal of carbon dioxide and hydrogen sulfide from the raw product gas. Finally, carbon monoxide and hydrogen in the approximate ratio of 1 to 3 are reacted over a methanation catalyst to produce additional methane.

After the methanation step, the heating value of the SNG is in the range of 900 to 1000 Btu/scf.

The Lurgi Process

The Lurgi process could provide fuel for a power plant that combined the Lurgi process with a gas turbine.

Coal is introduced in the top of the gasifier after having passed through a crusher and a pressurized hopper. Air and steam are introduced through slots in the grating at the bottom of the gasifier. The oxygen in the air combines with coal in the combustion zone to form CO_2. Simultaneously coal is using the energy given off by combustion to react with steam to form CO and H_2. The endothermic reaction of C and H_2O keeps the temperature down. As the gases pass upward some carbon dioxide reacts with the coal to form carbon monoxide and some methane is formed. The fresh coal introduced in the top undergoes successive drying, devolitization and reaction with oxygen and steam. The volatile fraction of the coal cracks to form methane, hydrogen and other light hydrocarbons. The gasifier efficiency is approximately ninety-five percent with losses due to unburned material and some heat losses.

The crude gas contains sixteen percent CO, twenty-five percent H_2, and five percent CH_4. The gas is under approximately twenty atmospheres pressure and requires purification before it is ready for a gas turbine. The gas is under pressure and because of this it can be completely cleansed of solids (1-2%) by a quenching wash with hot water containing tar. The dust contained in the gas is bonded to the tar in the water and removed. The cooling caused by the quenching wash is responsible for the condensation of the tars contained in the gas and they too are removed. The washing process also removes all traces of alkali and chlorine which would be detrimental to a turbine. After this washing process the gas is ready for the gas turbine and has increased in volume fifty percent due to saturation by steam.

Although the gas is ready for the turbine the sulphur content must be lowered by a considerable margin before it can be released to the atmosphere. Ninety-five percent of the sulphur content of the gas is hydrogen sulfide, which can be removed by washing the gas with an ammoniacal liquor according to the following reaction:

$$NH_3 + H_2O + H_2S = NH_4HS + H_2O$$

The sulphur recovered in this manner is not completely lost. It can act as a feed stream and be converted into salable sulphuric acid. When the sulphur is used to produce sulphuric acid the cost of meeting the emission standards by removing the sulphur is .336 mills/kwh.

The synthetic fuel gas is now fed to a pressure reduction turbine to reduce the gas pressure from 300 psig to 140 psig. The turbine is used to compress the air feed to the gasifier. The fuel gas is now fed to a combustor and the gas turbine. The gas is burned in the combustor with stoichiometric amounts of air. The boiler is placed between the combustor and the gas turbine to control the temperature of the gas fed to the turbine without using excess air.

The present Lurgi process consists of five discrete steps:

1. Pressure gasification-formation of the crude contaminated gas.
2. Shift conversion-adjustment of the H_2/CO ratio to facilitate subsequent methanation, hydrogenation of carbonization products, and desulfurization of naptha gas.
3. Rectisol gas purification-adsorption process with organic solvents (preferentially methanol) to remove all impurities.

4. Methane synthesis-conversion of clean components (essentially CO and H_2 of gas to methane.
5. Gas liquor treatment-removal of phenols and ammonia (this is a side stream).

All parts of the Lurgi process have been proved in operating plants except for methanation to the point of comparability with natural gas. Successful bench scale tests have been concluded and demonstration of the process is underway to produce a gas having 970 Btu/cu ft.

Overall efficiency of the process is about 68 to 70%, so the current gasifier with a capacity of about 500 million Btu input would produce about 350,000 cu ft/hr of gas. A 250-million cfd plant would require about 30 of the standard gasifier units, which are each about 12 ft in diameter. The equipment is now as big as it can be for convenient transport. If it were made much bigger, it would have to be site assembled.

At present the conversion of coal to gas by the Lurgi process is cheaper than the conversion of coal to the same number of BTU's of electricity.

Three major energy companies announced in October 1972 that they were starting immediately on technical and economic feasibility studies for the construction of a gasification plant in northwest New Mexico. They are Texas Eastern Transmission Corp., Utah International Inc., and Pacific Lighting Corp. According to the announcement, they hope to begin operating one 250-million cfd plant in 1975 and the possibility of adding three additional plants in the future is being considered.

If the project proves feasible, Texas Eastern and Pacific Lighting will build and operate the plant, and they will contract with Utah International for the coal.

It is estimated that each 250-million cfd plant would consume 7.5 million tons of coal a year.

El Paso Natural Gas Company was the first firm to announce definite plans to build a 250-million cfd gasification plant. It applied to the FPC in November, 1972 for approval to build facilities based on the Lurgi process with methanation added. Initial plans called for startup in 1976 with full production attained in 1977. The gas is expected to have a heating value of 950 Btu/cu ft. Gas that El Paso currently delivers to California has an average heating value of 1070 Btu/cu ft.

The plant would be located in northwest New Mexico and would consume about 8.8 million tons of subbituminous coal per year. El Paso Gas and Consolidation Coal Company jointly hold a coal lease on 40,000 acres of land on the Navajo Indian Reservation. It is estimated that the land contains over 600 million tons of recoverable coal under less than 150 feet of over-burden. Therefore, conventional surface mining methods can be used.

HYGAS

In the HYGAS process, coal is first crushed, dried, and sized, and then sent to the pretreatment section. Here, agglomerating coals such as Eastern bituminous coals undergo a mild surface oxidation with air at about 800 ^{o}F. to prevent agglomeration in the hydrogasifier. Research is being directed toward eliminating this process step. Nonagglomerating coals, such as lignite and subbituminous; do not require pretreatment. The feed coal is slurried with a light oil (a byproduct of the process), pumped to hydrogasifier pressure (1,000 pounds per square inch gage), and fed to the top of the 135-foot hydrogasifier (reactor) vessel. In the upper section of the hydrogasifier, the slurry oil is evaporated. The vaporized oil leaves the vessel with the product gas from which it is then separated and later recovered for recycle. The coal falls by gravity through the reactor, passing first through a low-temperature (1,200° to 1,400 $^{\circ}$F.) gasification zone where methane is primarily generated from the volatile matter in the coal. The devolatilized coal next passes into the lower section of the reactor. Here, the coal is hydrogasified at 1,700° to 1,800 $^{\circ}$F. to methane by reaction with hydrogen and steam. This methane joins with the methane generated in the upper section to exit from the top of the hydrogasifier as the main constituent of the product gas. The product gas also contains hydrogen, steam, carbon dioxide, and carbon monoxide, along with hydrogen sulfide and other impurities.

To make this gas suitable for injection into the pipeline system, the gas must first be purified. It is scrubbed to remove carbon dioxide and sulphur-bearing gases. (The sulphur-bearing gases are further processed to produce elemental sulphur, a byproduct of the process.) The purified gas passes into a catalytic methanation section. Here, the carbon monoxide and hydrogen react in the presence of a catalyst at a pressure of 1,000 pounds per square inch and at temperatures ranging from 550° to 850 $^{\circ}$F to form additional methane. The product gas, which is predominantly methane, is subsequently dried to remove the steam formed in methanation to produce the final produce-methane. At 1,000 pounds per square inch gage pressure, it is suitable for injection into a natural gas pipeline.

The reacted coal, now called char, is discharged from the bottom of the hydrogasifier. Approximately half of the initial coal fed to the hydrogasifier is gasified to methane. The remaining char contains significant amounts of unreacted carbon and can be used in any of several processes to generate the hydrogen-rich gas necessary in the HYGAS process.

The HYGAS pilot plant in Chicago for conversion of coal to pipeline quality gas has been made operational. The plant, together with supportive equipment, represents a capital investment of about $10 million. It is designed to convert 75 tons of coal per day to 1.5 million cubic feet of high-Btu gas.

Pilot plant construction began in 1969 and was completed in 1971. As of the fourth quarter of 1972, several significant operating runs have been made; the most notable being successful operation at 1,000 pounds per square inch gage. This is the pressure at which both the heat-generating methane-forming reactions and the heat-absorbing steam-carbon reactions occur at significant rates and is the pressure upon which the commercial plant design is based. Concentration of methane in the hydrogasifier effluent exceeded 40 percent. This corresponds closely to the design concentration. Operating problems, with essentially off-the-shelf mechanical equipment which delayed initial gas production, continue to be troublesome and require frequent shutting down of the hydrogasifier. The repeated heatup and shutdown has caused refractory spallins in the reactor and plugging of transfer lines. Unexpected severe expansion and concentration of high temperature internal piping has also been a problem. These conditions are being solved one at a time and semicontinuous operation of the hydrogasifier has been achieved. The gas purification and methanation systems have been checked out and are on standby awaiting continuous operation of the hydrogasifier[1].

Construction of the electrothermal gasification section was completed in June 1972. It has been pressure tested to 1800 psig and the electrical control system has been tested extensively. Operation of the HYGAS section of the plant with the package hydrogen plant is expected to be completed this spring and operation with the electrothermal gasifier can begin then.

Development work is also continuing on steam-oxygen gasification of coal char. The novel feature of this development is the gasification of char under nonslagging conditions in a high-pressure fluidized bed. Estimated construction cost for this section is about $2.5 million. Construction is projected to be completed by mid-1974, by which time testing with the HYGAS-electrothermal gasifier combination should be completed. Integration of the steam-oxygen gasifier will then be made with the HYGAS reactor for subsequent tests.

CO_2 Acceptor Process

Another process for which a demonstration plant has been constructed is the CO_2 Acceptor Process, developed by Consolidation Coal Company. Total funds for construction of the plant (over $9 million) were furnished by OCR. It will take an estimated $5 million per year to operate the plant. The plant is designed to use 1.5 tons per day of lignite and 3 tons of dolomite to produce 2 million scfd of 375-Btu/scf gas.

It is estimated that a commerical lignite gasification plant using the CO_2 Acceptor Process would cost about $150 million, use 30,000 tons of lignite per day, and produce 250 million scfd of pipeline gas. Present estimates indicate the gas would be in the $1/Mcf price range. Start of construction of the first commercial plant is projected for sometime in the 1974-76 period.

The unique feature of the CO_2 Acceptor Coal-Gasification Process is the circulation of calcined dolomite through a fluidized bed of lignite char operating under gasification conditions. The reaction of dolomite with carbon dioxide, one of the gasification reaction products, liberates heat sufficient to sustain the endothermic carbon-steam reaction, and also results in a product gas enriched in methane, and particularly enriched in hydrogen. Spent dolomite from the gasification zone is calcined in a separate regenerator using air and high-ash char from gasification as a source of fuel, thus eliminating the need for an expensive oxygen plant.

The development of this concept by Consolidation Coal Company had been carried through the laboratory stage by 1964 when the Office of Coal Research awarded a contract to complete the bench-scale development of the process. This phase was completed successfully in 1968. Feasibility studies before and after the bench-scale work indicated the process had potential commercial possibilities.

The conceptual design of a pilot plant was completed in April 1967. Design of the pilot plant was based upon extrapolation of bench-scale data obtained in the 1964 to 1968 period. The pilot plant is designed to operate at pressures of 150 to 300 per square inch gage and temperatures up to 1,800 ^{o}F. Proper operation requires carefully controlled flows of char and dolomite, as well as fluidizing gases, to the several fluidized vessels under balanced pressure conditions.

Construction of the $9 million pilot plant at Rapid City, South Dakota, was initiated in January 1970, and completed in November 1971.

At the completion of the plant shakedown tests in April 1972, a series of startup attempts was initiated. Each run was terminated due to some mechanical problems which have since been solved.

BI-GAS

The BI-GAS process employs an entrained bed, rather than a fixed or fluidized bed, and all types of coal may be used in the gasifier without pretreatment. The two-stage gasifier is said to be relatively simple in design and subject to scale-up to very large installations. Work has been carried out on a laboratory scale with a 100-lb/hr reactor. General objective of this test program was to optimize the controlling operating variables of temperature, pressure and residence time, for maximum methane formation in Stage 2 of the gasifier. The program reportedly confirmed the original concept that methane could be produced in high yield directly from coal in an entrained gasifier.

Present methanation processes are based on fixed-bed catalytic reactors. In connection with the BI-GAS program, work is directed toward development of a methanation system based on a fluidized-bed catalytic reactor. Design details for a nominal 6000 scfh fluidized-bed unit have been completed and equipment erected. Data from this unit will be used for the design of the pilot plant methanator.

The heat of the BI-GAS process is the two-stage gasifier which uses pulverized coal (70 percent minus 200 mesh) in entrained flow. Fresh coal and steam are introduced into the upper section (stage 2) of the gasifier at pressures in the range of 70 to 100 atmospheres. In stage 2, the coal comes in contact with a rising stream of hot synthesis gas produced in the lower section (stage 1) and is partially converted into methane and more synthesis gas. The residual char entrained in raw product gas is swept upward and out of the gasifier. The char is separated from the product gas stream and recycled to stage 1 of the gasifier.

In stage 1, the char is completely gasified under slagging conditions with oxygen and steam, producing both the synthesis gas and the heat required in stage 1 for the partial gasification of the fresh coal.

The raw product gas from stage 2 is purified by removal of hydrogen sulfide and carbon dioxide and upgraded in Btu content to pipeline quality by catalytic methanation.

The BI-GAS process offers several advantages in the production of synthetic natural gas:

1. A high yield of methane is obtained directly from coal, and subsequent processing of the product gas is minimized.

2. Because it is entrained rather than a fixed or fluidized-bed system, all types of coal should be amenable without prior treatment for use in this gasifier.

3. The conditions in stage 2 are such that no tar and oils are formed in the gasification process.

4. All the feed coal is consumed in the process; principal byproducts are slag for disposal and sulphur for sale.

ATGAS

The ATGAS process uses molten iron to gasify all types of coal with steam and oxygen at low pressure for the production of a gas suitable for conversion to synthetic natural gas. The ATGAS process eliminates the problem of feeding coal into high pressure gasifiers. Any type and size of coal can be used for synthetic natural gas production.

The gasifier is a cylindrical refractory-lined vessel (Figure 20) containing molten iron with a slag layer floating on the iron. Coal and limestone are injected through tubes (lances) placed relatively deep in the molten iron, using steam as the carrier. The coal devolatilizes with some thermal cracking of the volatiles leaving the fixed carbon and sulphur to dissolve in the iron. The dissolved carbon is oxidized to carbon monoxide with oxygen that is introduced via lances shallowly immersed in the iron bath. The dissolved sulphur (both organic

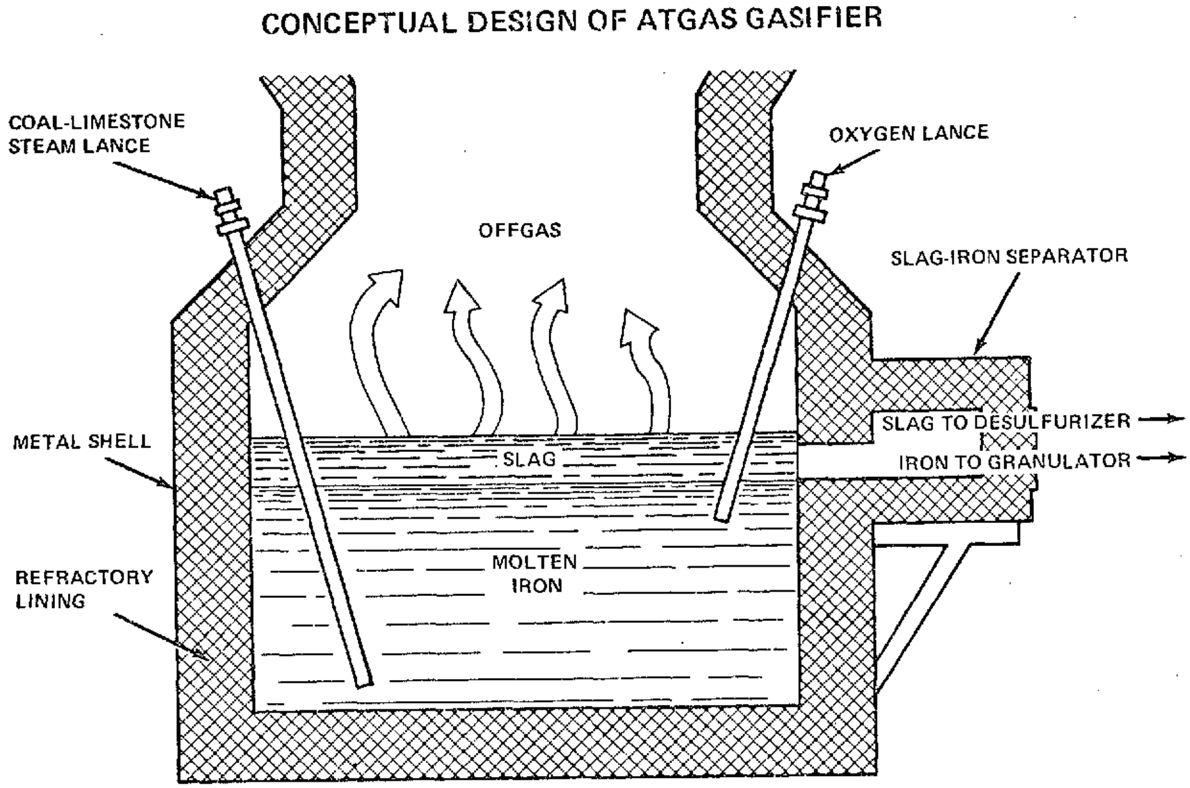

Figure 20. Conceptual Design of ATGAS Gasifier

and pyritic) migrates from the molten iron to the slag layer where it reacts with the lime to produce calcium sulfide. Provided the carbon content of the molten iron is maintained relatively high (3 to 4 percent), the injected oxygen and steam preferentially react with carbon without sulphur oxidation to form hydrogen and carbon monoxide. Thus, the oxidation of fixed carbon, the cracking of volatile matter, and dissociation of water (introduced via the reactor with the coal) produce a hot (2,600 ^{O}F) off gas consisting mainly of carbon monoxide, hydrogen, and possibly methane.

Capital investment for a 250 MMscfd ATGAS plant is eatimated to be about \$200 million. With 12,600 Btu/lb coal at 30¢/million Btu, the estimated 20-year average price of gas is \$1.10/million Btu. With the same coal available at 20¢/ million Btu, the average price would be 95¢/million Btu.

Self-Agglomerating Gasification Process

This process is a two-stage fluidized-bed system for steam gasification of coal. The heat requirement for the endothermic gasification reaction is developed by fluidized-bed combustion of a part of the carbon bed. Air is used for combustion. The heat for the gasification reaction is provided by recirculation of coal ash from the burner through a fluidized-bed gasifier.

A major feature of the process is the method of combustion which applies the "self-agglomerating" fluidized-bed technique for burning coal with simultaneous pelletization of the ash during the combustion. The ash agglomerates formed in the combustion bed are free-flowing spherical particles. These are circulated through the gasifier as a direct-contact heat-transfer medium to provide the heat for the steam-carbon reaction. This pelletized ash, after giving up a part of its sensible heat in the gasifier, is returned to the burner to moderate the burner temperature and be reheated for return to the gasifier.

In addition to providing a pelletized heat-transfer medium to the gasifier, the self-agglomerating fluidized-bed burner is effective for collecting the ash contained in the incoming fuel. Thus, the fuel can be burned to yield a combustion gas essentially free of flyash. This particulate-free hot combustion gas can then be expanded in an open-cycle gas turbine for recovery of kinetic energy.

Koppers-Totzek Process

In the K-T process (Figure 21), coal is reacted with steam and oxygen in a patented gasifier to form a raw synthesis gas. The gas is cooled and all particulate matter is removed. Upgrading to natural gas quality would involve chemically removing the acid gases produced and then shift conversion and methanation steps. Because of the high temperature reaction in the gasifier (about 2700 F),

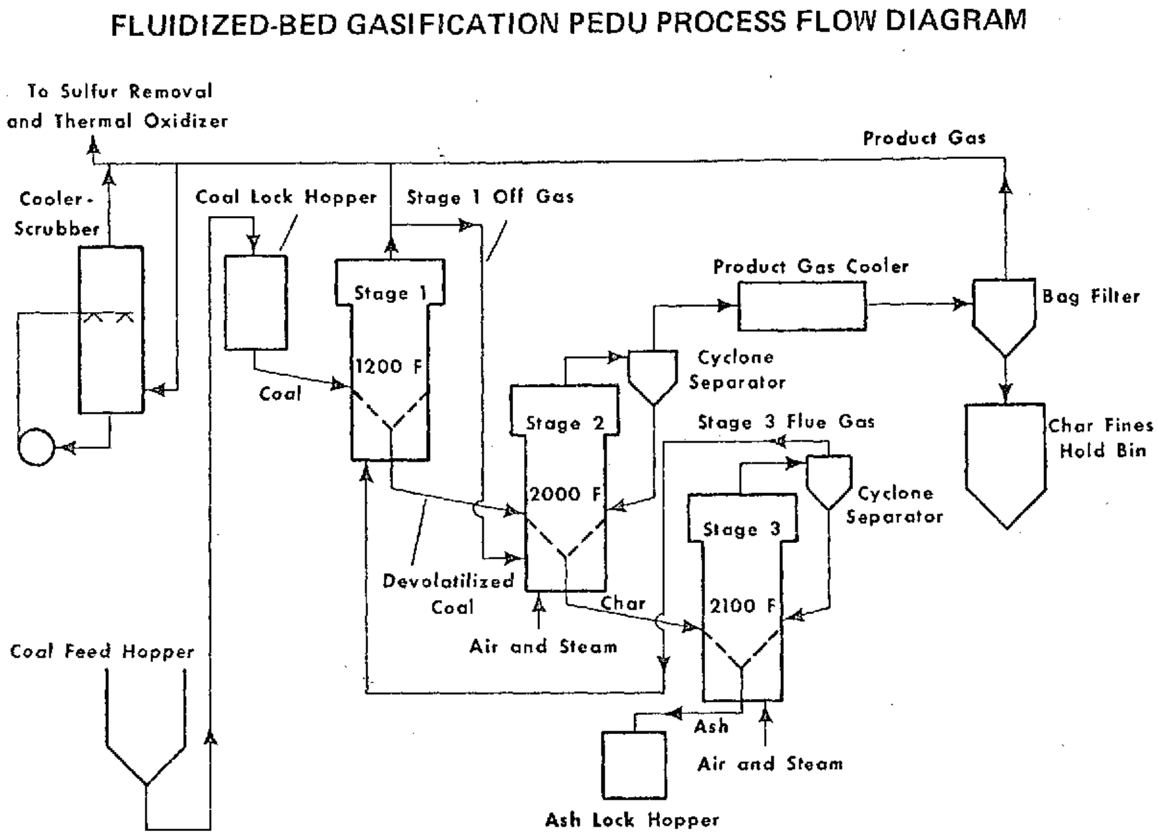

Figure 21. Koppers-Totzek Process

it is claimed that the raw gas produced by the K-T process is free of condensable organic compounds. Therefore, potential gaseous or liquid pollutants such as ammonia or phenotic effluents are not produced.

Koppers Company designed and built the first demonstration unit for gasifying coal in suspension based on the K-T process in 1948 for the U. S. Bureau of Mines in Missouri to demonstrate the feasibility of using the process to produce gas for conversion to synthetic liquid fuels. It was operated jointly by the Bureau and Koppers Company with the assistance of Heinrich Koppers engineers. Production at the plant was discontinued in 1950 after a successful demonstration period.

The design of a process and equipment development unit (PEDU) for studying fluidized-bed catalytic methanation was completed in 1971 under subcontract with

Koppers Company, Inc. The 6,000-cubic-foot-per-hour PEDU was scheduled to be operational early in 1973.

The Slurry Methanation Process

In this process an inert liquid is pumped upward through the reactor at a velocity sufficient to fluidize the material and remove the reaction heat. The low BTU feed gas is also passed upward through the reactor so it is converted to a high concentration methane stream. This process is illustrated in Figure 22.

SLURRY METHANATION EXPLORATORY UNIT

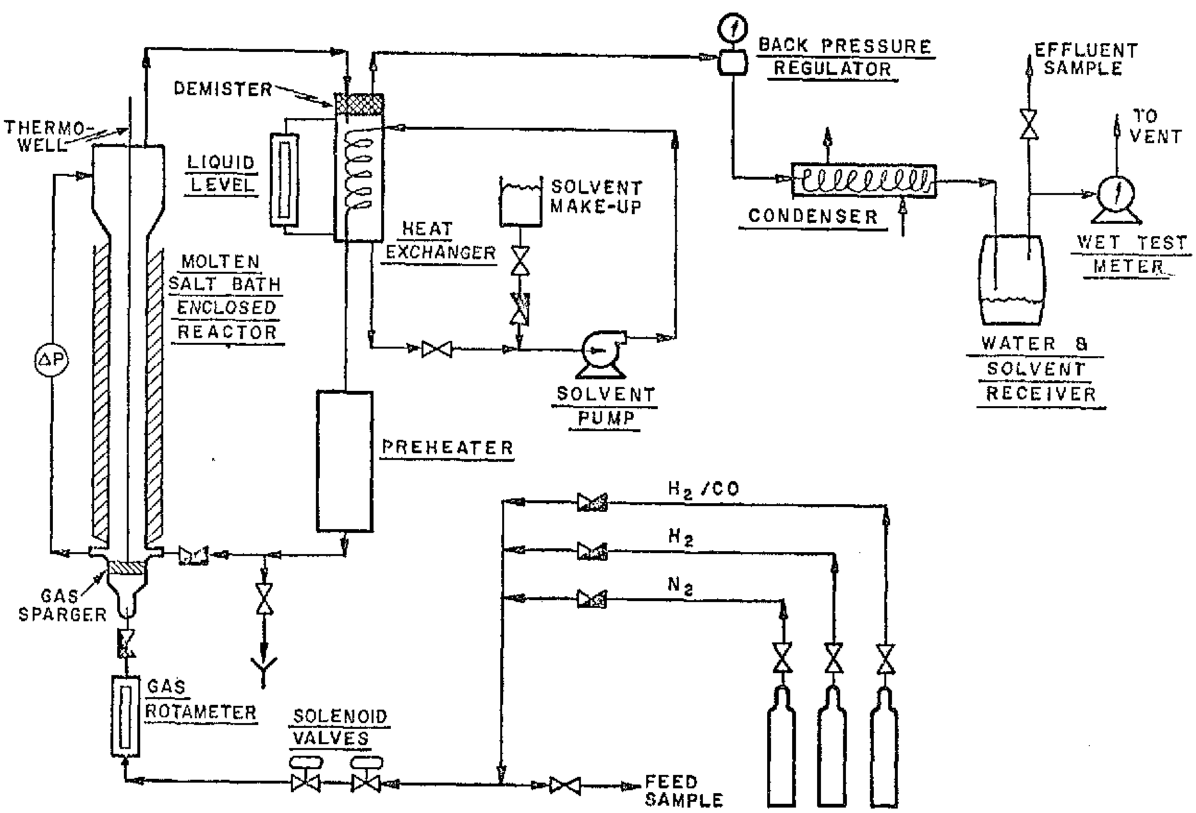

Figure 22. Slurry Methanation Process

Electrofluid Coal Processing

In the electrofluid reactor, coal char is heated by passage of an electric current through a fluidized bed of conducting char particles. A process for production of synthesis gas from coal char and steam has been demonstrated in bench-scale reactors. Moreover, the Institute of Gas Technology has adopted this method to generate synthesis gas for the HYGAS pilot plant in Chicago, Ill., and the method may be incorporated in future large-scale commercial plants for manufacturing methane.

The gasification process was demonstrated by employing a 12-inch diameter electrofluid-bed reactor which was operated both batchwise and with continuous feeding of coal char. Reasonably adequate steam conversions and gasification rates were obtained while operating at atmospheric pressure and temperature in the range of $1,400^{\circ}$ to $1,900\ ^{\circ}F$. The operation was generally smooth with no serious difficulty encountered in controlling electrical power. However, it became evident that the electrodes in contact with the fluidized bed could become overheated which tended to shorten electrode life. Moreover, a preliminary study of the electrical characteristics of fluidized-bed systems showed that these characteristics were complex and that engineering methods for measuring, analyzing, and predicting them needed to be developed in order to properly design industrial-scale reactors. (Figure 23).

The 12-inch diameter reactor was modified and operated to further evaluate the coal char gasification process. The modification included changes in the electrode system and power supply so the reactor could be operated on three-phase power. These changes enabled operation with higher power inputs. Electrodes made of silicon carbide were tested extensively and found to be quite durable.

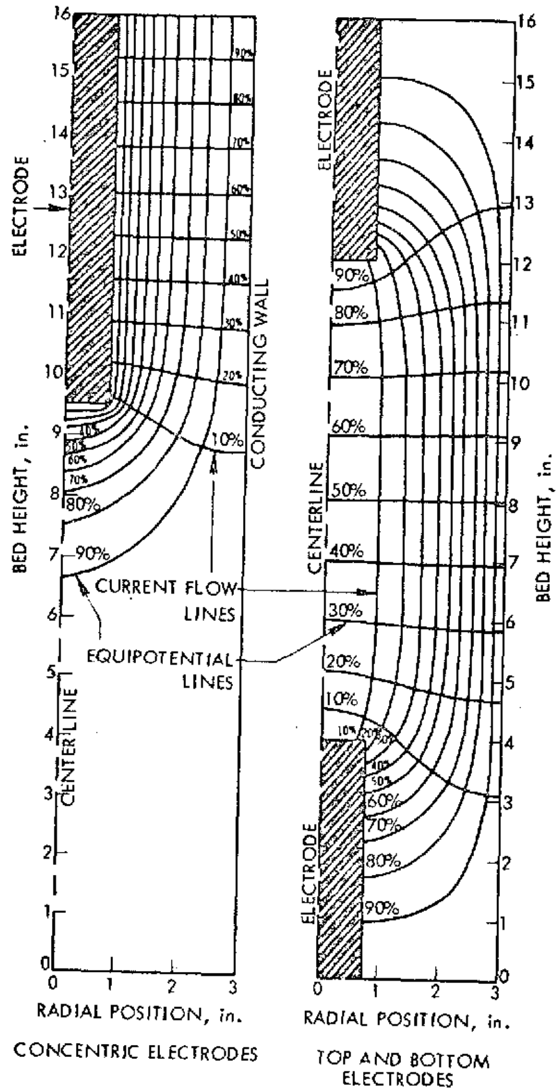

Figure 23. Current Distributions in Electrofluid Coal Gasifiers

However, under some conditions the electrodes became heavily coated with ash or slag. The extent of coating appeared to be related to the char source. The electrical characteristics of fluidized-bed systems were also investigated extensively. The resistivity of fluidized beds was measured under a wide variety of conditions including temperatures varying from ambient to 1,500 ^{o}F. Arcing or sparking in fluidized beds as well as electrode-to-bed contact resistance received attention. At the same time, extensive use of field theory was made to predict and analyze the electrical characteristics of fluidized beds. A preliminary demonstration of the feasibility of a process for producing carbon disulfide by reacting sulphur and coal char in an electrofluid reactor was also completed. The demonstration included operating the electrofluid-reaction system over a range of temperatures and sulphur feed rates.

NEW TECHNOLOGIES

Fluid-Bed Boilers

Fluidized beds have two major attributes arising from the rapid agitation of the relatively dense particle phase: (1) rapid heat and mass transfer occurs between the gas and the particles, and (2) high heat transfer coefficients are obtained at surfaces immersed within the bed in comparison with gas-to-surface heat exchange.

Early research work into fluidized combustion utilized only the high heat and mass transfer between the phases in attempts to burn fuels intractable to conventional methods, e.g.anthracite fines, lignite, oil shale, and washery tailings. Much of this work was successful, resulting in at least one commerical system. However, the approach to heat utilization was conventional in that the aim was to heat the combustion gases to the maximum obtainable temperature and pass them through conventional water-tube boiler systems. For fuels with an ash content less than about 70 percent, combustion in the fluidized bed was so rapid that the combustion temperature was higher than the melting point of the ash.

With heat extracted directly from tubes in the bed, very high heat release rates could be obtained, resulting in a more compact boiler (compared with conventional plant) and a consequent reduction in capital cost. It also seemed likely that operating costs would be reduced by the use of low-grade fuels and that the relatively low combustion temperatures would alleviate deposit and corrosion troubles.

In the boiler shown in Figure 24, coal was pneumatically fed to the center of the bed just above the air distributor, and the flue gases passed through a heat exchanger to a cyclone. The particles from the cyclone could be passed to waste or recycled to the combustor in any required proportion. The combustor was water cooled.

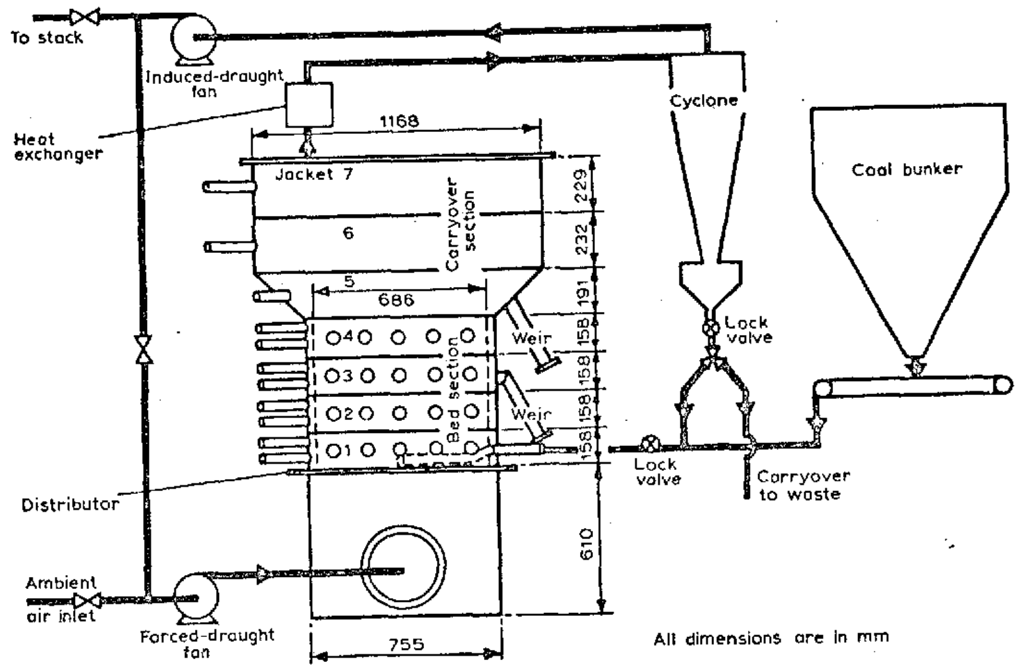

Figure 24. Fluidized-Bed Boiler

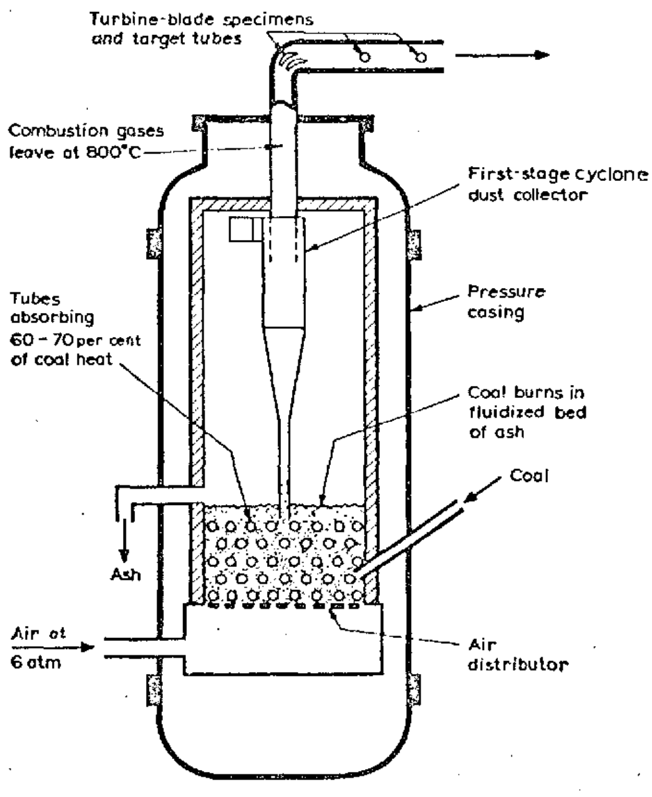

Figure 25. 4 Ft. x 2 Ft. Fluidized Bed Combustor

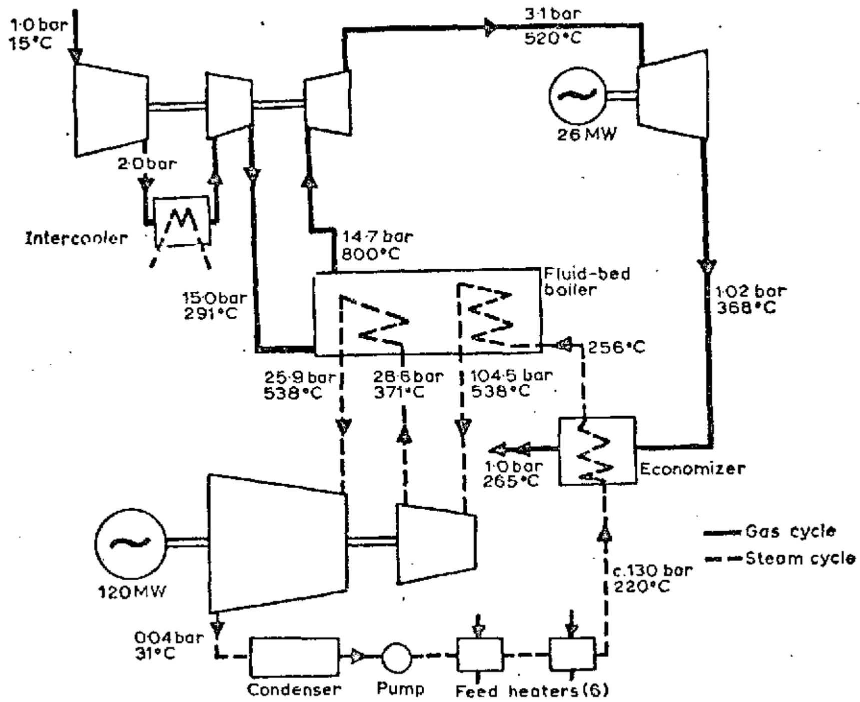

Figure 26. Combined Cycle Power Plant

Figure 25 illustrates a small fluidized bed boiler, and Figure 26 a 140 MW_e combined cycle power plant using a fluidized bed boiler.

MHD

Magnetohydrodynamics has great potential for supplying electricity at higher efficiencies than at present, and with minimum environmental impact. While the principle has been demonstrated often in short-time experiments of relatively small scale, a great deal of work remains to be done before the availability of long-lived coal-fired central-station MHD generating units becomes a reality.

Fuel is burned at a pressure of 6 or 7 atmospheres, and the resulting hot gas then flows at a high velocity through a duct within a magnetic field. The gas must be at such a high temperature that it is electrically conductive. (This conductivity may be enhanced by potassium or cesium seed.) When a conductor cuts a magnetic field an electric current is generated-as in the ordinary rotating turbine-driven generator. Electrodes on the sides of the duct collect the current.

This constitutes a thermal-electric generator with no moving mechanical parts. The gas from the MHD duct, still very hot, may flow to a conventional steam boiler to power a standard steam turbogenerator. The first generation of such plants is expected to reach a thermal efficiency of around 50 percent. Eventually 60 percent is believed attainable.

Aside from the need for better understanding of the dynamics within the MHD duct, the problems are largely associated with the very high temperatures which require the development of new materials and methods of construction for dependable performance over a period of years. There are additional problems associated with seed recovery, coal ash and slag, and large superconducting magnets. Nonetheless, rational solutions are envisioned.

AIR POLLUTION

Health Effects

The most obvious adverse environmental effect of energy generation to date has been the air pollution which is evident in most major cities of the world. This air pollution is almost entirely due to the combustion of fossil fuels, and results in damage to people, to property, and to plant and animal life. Table 10 lists the five major pollutants and their sources.

Table 10. Sources of Air Pollution (millions of tons per year)

Source	CO	SO_x	NO_x	Hydro-carbons	Particu-lates	Total	%
Transportation	66	1	6	12	1	86	60
Industry	2	9	2	4	6	25	17
Electric Power	1	12	3	1	3	20	14
Heating	2	3	1	1	1	8	6
Waste Disposal	1	1	1	1	1	4	3
TOTAL	72	25	12	18	12	143	100

As can be seen, even though electric power plants burn about 25% of fossil fuels, they only contribute 14% of the air pollution. Internal combustion engines, with their low efficiency, release 2/3 of the unburned hydrocarbons, practically all of the carbon monoxide, and 60% of all air pollution. Internal combustion vehicles and industry are also concentrated in areas of high population density, whereas power plants tend to be located on the outskirts of these areas. Thus, the automobile is the worst polluter. Cleaning up automobile emissions alone should tremendously reduce air pollution in the large cities. Space heating consumes as much energy as transportation but produces very little air pollution because most space heating is done with gas, the cleanest of the fossil fuels. In some areas, electric power companies are being required by law to burn gas or oil instead of coal in order to meet emission standards. Table 11 presents emission rates for the five major pollutants from a fossil fueled power plant assuming no pollution control equipment, other than flyash control when coal is burned. Electrostatic precipitation can remove practically all of the particles from the exhaust. The gaseous pollutants are difficult to remove.

Table 11. Annual Release from a 100 MW_e Power Plant (millions of pounds)

	Coal	Oil	Gas
CO	1.15	0.018	---
NO_x	46	48	27
SO_x	306	116	0.027
Hydrocarbons	0.46	1.47	---
Particulates	10	1.6	1.02

Perhaps the most serious single air pollution incident was the London smog in the winter of 1952-1953 in which 4000 people died. At that time the primary fuel for space heating and industry was high sulphur coal. The high atmospheric concentration of sulphur oxides, which combine with fog droplets to form sulphuric acid, was responsible for most of these deaths. Since that time, the British government passed the Clean Air Act, and it is being enforced. This Act requires residents of London and other parts of Britain to burn only smokeless fuels in their homes and requires smoke from factory chimneys to be controlled. Since this act was passed, smog has practically disappeared from London.

When an electric utility shifts from high sulphur coal (2-3% sulphur) to low sulphur coal (1% or less) or other cleaner fuels, its fuel costs increase. For example, in 1967 when Consolidated Edison contracted for 1% sulphur coal to replace the 1.6% sulphur coal they had been using, their fuel costs increased from 33¢/Mbtu to 37¢/Mbtu, an annual cost increase of $7.5 million. This cost increase was, of course, passed on to the consumer through a rate increase. Burning low sulphur coal reduces the efficiency of electrostatic precipitators, so simply shifting to low sulphur coal in a plant results in a decrease in SO_2 emission and an increase in the release of particulates. New York City's regulations require that 99% of the particulates be collected. Some plants which had been operating with 99% collection efficiency released more particulates when the switch was made to low sulphur coal, so expensive additional equipment had to be installed to reduce particulate emissions to the previous level. Many utilities are required to burn low sulphur oil (1% or less), which is considerably more expensive than oil with a higher sulphur content and has a lower viscosity, resulting in equipment changes. The first commercial desulfurization plant for fuel oil is now operating in Venezuela and will furnish 100,000 barrels a day to the United States. This plant reduces the sulphur content from 2.6 to 0.5 percent. The requirement of low sulphur content has increased the prices of usable coal and oil to the extent that natural gas is economically competitive in some areas.

There is a synergistic effect with SO_2 and particulates, over 75% of which are from industry and power plants. In the presence of atmospheric particles which contain iron, manganese, or vanadium, SO_2 reacts to form sulfuric acid, a severe irritant to the bronchial system and lungs. This accounted for the large number of deaths from the London smog. SO_2 and particulates together are more damaging than either alone.

The dolomite process has recently been utilized by several power plants to reduce SO_2 emissions. Dolomite, a limestone, is injected into the combustion chamber as a powder where it reacts with about 20% of the SO_2 and practically all of the SO_3. The gas then flows to a wet scrubber containing an aqueous suspension of limestone or lime particles that removes more SO_2 as well as the fly ash. This system removes about 80% of the SO_2, essentially all of the SO_3, about 20% of the nitrous oxides, and 99% of the flyash. The resulting total solids collected is three times greater than the fly ash alone, so a solid waste disposal problem has been substituted for an air pollution problem.

Most hydrocarbons and oxides of nitrogen are released into the air of our cities by internal combustion vehicles. These hydrocarbons react with the nitrogen oxides in the presence of solar ultraviolet light to produce photochemical smog of the type that appears so often over Los Angeles and other cities. These reactions produce ozone and complex organic compounds which can have a serious effect on people, animal life, and vegetation. Ozone particularly is highly damaging to plant life. Photochemical smog is basically different from the type of smog formed from high SO_2 concentrations. Also, the automobile is the primary source of the pollutants which cause photochemical smog, whereas the sulfurous smog is the result primarily of factories and power plants. The effects of either type of pollution on people can be quite serious, especially for those with allergies or other respiratory conditions. New emission standards for automobiles to go into effect in 1975 should reduce emission of carbon monoxide and unburned hydrocarbons considerably.

Seven common respiratory diseases which have been associated with air pollution are cancer of the respiratory system, chronic bronchitis, acute bronchitis, the common cold, pneumonia, emphysema, and asthma. Ridker[14] calculated the total cost in the United States of these respiratory diseases in terms of 1958 dollars to be $2 billion. Quite a few studies have been carried out using the basic numbers provided by Ridker, apportioning a part of this respiratory disease cost to air pollution. The usual way of doing this is to compare the incidence of respiratory disease in urban and rural areas and attribute the difference in incidence to air pollution in the urban areas. The ratio of urban incidence to rural incidence is called the urban factor.

Lave and Seskin[15] provided a detailed analysis of studies up to that time which indicated a strong correlation between the urban factor and respiratory disease. In the case of air pollution and lung cancer they cited studies showing a ten-fold difference between death rates in rural and urban areas in England, and another study showing that the urban death rate due to lung cancer is twice as high as that in rural areas of England, and another study showing that the urban death rate due to lung cancer is twice as high as that in rural areas of England and Wales. Evidence for other parts of Europe also shows an association between lung cancer and the urban factor. Also cited are American studies which show that the death rate due to lung cancer is 34 per 100,000 in rural areas as compared to 56 per 100,000 in cities with population over 50,000. When standarized with respect to both smoking habits and age, this lung cancer rate is adjusted to 39 in rural areas as opposed to 52 in cities of over 50,000, which indicates that the urban factor is responsible for 25% of lung cancer in cities. Buell et al.[16] summarized lung cancer mortality studies to that time and showed that the ratio of the lung cancer rate in the city to that in rural areas ranged from 1.26 to 2.23, and was slightly higher when only non-smokers were considered. Also, studies of the mortality rate due to cardiovascular disease have shown that the mortality rate is 10% to 20% higher in urban areas as opposed to rural areas. These comparisons are typically made of matched groups with similar smoking habits. As a result of these and other studies, Lave and Seskin concluded that "there would be a 25 to 50% reduction in morbidity and mortality due to bronchitis if air pollution in the major urban areas was abated by about 50%," and that "about 25% of the mortality from lung cancer could also be saved by a 50% reduction in air pollution." These conclusions are based on the assumption that the urban factor is entirely due to air pollution in the case of respiratory disease, including lung cancer. Carrying this assumption one step further, they conclude that the urban factor would be eliminated by a 50% reduction in air pollution, since a 50% reduction in pollution would be expected to result in an air quality equal to that of the cleaner areas.

Using the correlation between urban and non-urban areas, and assuming the difference to be due to air pollution, over 20% of cardiovascular morbidity and about 20% of cardiovascular mortality could be eliminated if air pollution were reduced by 50%. Likewise, they estimated that 15% of non-respiratory cancer would be saved by a 50% reduction in air pollution.

The fallacy of these arguments, which are found throughout the literature describing health effects of air pollution, is the assumption that the urban factor is either due entirely to air pollution or is largely caused by air pollution. The basic assumption that is made, which seems reasonable until investigated further, is that the major causative factor for the difference in frequency of these diseases between urban and rural areas is the greater air pollution in the urban areas.

Goldsmith[17] analyzed data regarding respiratory disease, heart disease, and cancer and pointed out that there is a great deal of evidence favoring urban factors in the epidemiology of lung cancer and other respiratory disease, and that it appears to have a synergistic relationship to the well-established effect of cigarette smoking, but that "While many have considered that the factor might be air pollution, a number of consequences should follow which have not been observed: 1) the urban factor should be largest in those counties where there is the heaviest urban pollution; it is not, 2) assuming that the larger the city the greater the population exposure will be to air pollution, then the urban factor should increase regularly with city population; it does not, at least in the United States, 3) if exposure to urban pollution causes an augmentation in lung cancer, then the rates should be higher in lifetime urban residents than in migrants to urban areas; they are not, 4) correlations of lung cancer rate with major pollution should be found by studies in the United

Kingdom where lung cancer rates are high and pollution is great; a positive correlation is found with population density and not with pollution, 5) if the urban factor were community air pollution, it should affect women at least as much as men; it does not." Goldsmith continued, "There may be other explanations of the urban factor (greater smoking, occupational exposure, population density, infections), but the evidence presently available that it is air pollution does not confirm the suspicion of casualty which previously existed." Williamson[18] also discussed the urban factor and stated that "We emphasize that a casual relationship between air pollution and this factor has been neither established nor refuted. However, there is a strong possibility air pollution is at least a contributory cause." Obviously, air pollution does enhance respiratory disease, but the question which one must answer in order to arrive at realistic projections of health costs of air pollution is how much of respiratory disease is caused by air pollution. Lave and Seskin may have grossly overestimated the costs due to air pollution by attributing the urban factor solely to air pollution and assuming also that the urban factor could be eliminated by a 50% reduction in air pollution.

The Surgeon General's report on Smoking and Health[19] make it quite clear that cigarette smoking is the major cause of respiratory disease in the United States. Drastic increases over the last few decades in the incidence of respiratory disease and lung cancer are correlated with the rapid increase in cigarette smoking. As stated in the report, "Cigarette consumption in the United States has increased markedly since the turn of the century, when per capita consumption per person was 138. It rose to 1,365 in 1930, to 1,828 in 1940, to 3,332 in 1950, and to a peak of 3,986 in 1961. Similarly, lung cancer deaths, less than

3,000 in 1930, increased to 18,000 in 1950. In the short period since 1955, deaths from lung cancer rose from less than 27,000 to the 1962 total of 41,000. This extraordinary rise was not recorded for cancer at any other site. Deaths from heart disease also rose from 273,000 in 1940 to 578,000 in 1962. It is also shown that, in comparison with non-smokers, average male smokers of cigarettes have a ten-fold risk of developing lung cancer and heavy smokers at least a twenty-fold risk. Cigarette smoking is the most important of the causes of chronic bronchitis and emphysema." It is further stated that "for the bulk of the population in the United States, the relative importance of cigarette smoking as a cause of broncho-pulmonary disease is much greater than atmospheric pollution or occupational exposure." A recent report by the Environmental Protection Agency states that smoking causes three times as much respiratory disease as air pollution.[20]

In this paper actual data on incidence of respiratory disease are used in the analysis, which is physically reasonable and which properly accounts for the relative effects of smoking and air pollution. From the results of this analysis the following conclusions may be drawn regarding air pollution related respiratory disease: 1) the major cause of respiratory disease in the United States is cigarette smoking, and 2) although the incidence of these diseases in urban areas is greater than in rural areas, it has not been shown that this urban factor is primarily due to air pollution. There is evidence that air pollution is a contributor to the urban factor, but it is not the only contributor, and possibly not even the major contributor. Much of respiratory disease is communicable, and in urban areas the higher population density facilitates its transmission. Other infectious diseases (possibly including some forms of cancer) are more easily transmitted in the urban areas because of the higher population densities. Because of more crowded urban conditions, urban non-smokers also inhale more tobacco smoke produced by tobacco smokers than is the case for rural non-smokers. Also, significant differences exist between rural and urban areas with respect to life styles, diet, and other factors which can strongly affect the health of an individual. Another factor which could be a major contributor to the urban factor for death rates due to major illnesses is the fact that many rural people tend to go to a nearby major city to be treated for major illness. Since demographic data records deaths only by place of occurrence, if a rural person dies while hospitalized in a nearby city, this would show up in the urban death rate. Unless a detailed study is made to determine death rates by place of residence, this factor could have a big effect.

Bates[21] concluded that 70% of respiratory disease is due to cigarette smoking. This is in general agreement with the Surgeon General's report on Smoking and Health[19]. Thus, the percentage of respiratory disease due to cigarette smoking is taken to be 70%. Of the remaining 30% of respiratory disease, the urban factor accounts for 50% of the respiratory disease in cities, keeping in mind that studies of the urban factor compared groups of equal smoking habits in order to eliminate the effect of smoking.

Results cited by Goldsmith and others indicate that air pollution is not the major cause of the urban factor, since there is a stronger correlation between the urban factor and population density than there is between the urban factor and air pollution levels. Many factors help account for the difference in incidence between urban and rural areas, and air pollution is certainly one of these factors. In a few cases, such as Los Angeles, air pollution may in fact be the major cause of the urban factor; but in most cities, it is not. In arriving at total costs of respiratory disease due to air pollution, one must assign a portion of the urban factor (averaged over all metropolitan areas) to air pollution. It is the considered opinion of the authors that, in view of the many studies which have so far been reported, air pollution does not account for more than 50% of the urban factor. If the contribution were greater than 50%, strong correlations with air pollution levels would have been cited by Goldsmith[17] and Williamson[18], instead of the lack of correlation which they reported. On the other hand, the authors agree with Williamson in that "there is a strong possibility that air pollution is at least a contributory cause." Thus, we assign a minimum contribution of 10% of the urban factor to air pollution.

The effects of cigarette smoking and the urban factor are synergistic, not additive. Some previous cost studies make the mistake of assuming that these effects are additive and assign costs independently to the urban factor and cigarette smoking.

With regard to non-respiratory disease, there have been studies which show some correlation with the urban factor and smoking. But even though a slight correlation between the urban factor and non-respiratory diseases, such as cancer, has been shown to be valid, there is no justification at present for assuming that this correlation is due to air pollution. There are too many other factors which may be more important. Likewise, it has not yet been conclusively proven that smoking is a significant cause of non-respiratory disease.

The health cost of air pollution is calculated to be between $62 million and $311 million[22]. This is lower than some of ten-cited estimates of total health cost due to air pollution because most estimates don't separate out the effect of cigarette smoking, and they also start with the assumption that the urban factor is either totally or primarily due to air pollution. As has been pointed out clearly by Goldsmith and others, the urban factor is probably not primarily due to air pollution for a variety of reasons. It is probably more connected with factors such as: population density effects on transmission of infectious diseases, significant differences in life styles between urban and rural areas, urban non-smokers being affected more (because of higher population density) by inhalation of cigarette smoke produced by smokers, and rural persons dying after coming to a nearby city for hospitalization (thus contributing erroneously to the demographic data on urban death rate). Factors such as these may be major contributors to the so-called urban factor.

Lave and Seskin[15] calculated the total health cost of air pollution in 1963 to be $2.08 billion. They assumed that "25 percent of all morbidity and mortality due to respiratory disease could be saved by a 50 percent abatement in air pollution levels. Since the annual cost of respiratory disease is $4887 million, the amount saved by a 50 percent reduction in air pollution in major urban areas would be $1222 million." They also assumed that a 50 percent reduction in air pollution would reduce cardiovascular disease by 10 percent and reduce cancer by 15 percent, saving $468 million and $390 million, respectively. Thus, they arrived at a total 1963 cost of $2.08 billion which would be saved if air pollution were reduced 50 percent, resulting in an air quality equal to that of relatively non-polluted areas to which the polluted areas had been compared. In these estimates, half or more of the urban factor was attributed to air pollution, both for respiratory and non-respiratory disease.

Barrett and Waddell[23] further inflated the Lave and Seskin estimate by assuming that if a 50% reduction in air pollution would result in a savings of

\$4.16 billion. They arrived at a 1968 cost by multiplying the \$4.16 billion by the fractional increase in Gross National Product from 1963 to 1968, for a total health cost of \$6.06 billion. One difficulty with this estimate is that the data on which Lave and Seskin based their estimates of \$2.08 billion more properly represented a cost due to all air pollution, rather than costs due to half of the air pollution. Lave and Seskin spoke in terms of a 50% reduction in air pollution since that is what would be required to improve the air quality to that of relatively non-polluted areas, where air pollution was not believed to be a significant health factor.

The RECAT Committee took the inflated Barrett and Waddell estimate of \$6.06 billion to be a cost due to SO_2 and particulates alone, and by employing the Caretto-Sawyer emission severity factors, used it to project a total 1968 health cost of \$15.168 billion for all pollutants. Their reasoning was that since the air pollution index used by Lave and Seskin incorporated only SO_2 and particulate measurements, then the observed effects costing \$6.06 billion were due to SO_2 and particulates alone. This would be true if there were no correlation between SO_2 and particulate pollution and other types of air pollution, but in fact they usually do correlate strongly. During episodes and general adverse weather conditions, all pollutants usually show high concentrations, and in roughly the same areas. Thus, even though the numerous studies cited by Lave and Seskin often used only smoke or smoke and sulfation as an air pollution index, the effects which they report are usually effects due to all air pollution, not SO_2 and particulates alone. In fact, most of these correlations are actually with the urban factor (comparing "clean" rural areas with "dirty" urban areas) which may have little relation to air pollution. As stated by Barrett and Waddell, "Lave and Seskin seem to have a stronger faith in the magnitude, sign and statistical significance of their regression coefficients than what their analysis would seem to support. Their many statements about the causes of these 'effects' are not as justified as they seem to conclude." Lave and Seskin clearly intended their cost estimate of $2.08 billion to represent a cost of air pollution in general, not just SO_2 and particulates.

What has happened in arriving at the $15.168 billion health cost due to air pollution is that a rough estimate of $2.08 billion has been inflated twice using highly questionable techniques. The Lave and Seskin estimate of $2.08 billion for all air pollution was inflated by Barrett and Waddell to $6.06 billion for all air pollution; then the RECAT Committee took the $6.06 billion value to be only due to SO_2 and particulates, so proportional costs were assigned to CO ($303 million), hydrocarbons ($6.06 billion), and NO_x ($2.745 billion) based on severity factors and tonnages of emissions, for a total cost of $15.168 billion. This result is actually equivalent to the highly unrealistic assumption that 125% of all respiratory disease costs, plus 50% of all cardiovascular disease costs, plus 75% of all non-respiratory cancer, are attributable to air pollution.

If one starts with the basic numbers for respiratory disease costs, as provided by Ridker and by Lave and Seskin, and apportions these costs properly between smoking and the urban factor, and then takes a realistic percentage of the urban factor to be caused by air pollution, the resulting cost estimates are much more reasonable.

The major conclusion of this analysis is that cigarette smoking is a far more important cause of respiratory disease than air pollution. The dollar value of these respective costs were arrived at using Ridker's estimate for the total cost to society of respiratory disease based in loss of income, hospital expenses, and other discernable economic factors. Of course, the actual dollar value of human life and health is impossible to quantify since its value, in each individual case, depends on the viewpoint of the observer; i.e. whether the affected individual is an employee or the observer himself. However, regardless of the total assigned cost of respiratory disease, the conclusion regarding the relative importance of cigarette smoking and air pollution remains valid. The dollar values given in this paper represent an estimate of the overall loss to the economy of the United States due to these factors.

Costs

One of the earliest studies of the cost of air pollution damage was the 1913 Mellon Institute study of smoke damage in Pittsburgh. This study utilized the now-standard techniques of literature survey, questionnaires, and direct observation to evaluate a variety of costs related to smoke. The total damage cost estimate was $9.9 million, or $20 per person in the city of Pittsburgh in 1913. Although this study was for a very specific situation and included only soiling and materials damage due to smoke, it is important for two reasons: 1) it established a procedure for evaluating air pollution costs which has been used many times since 1913 to estimate costs due to air pollution, and 2) the resulting cost of $20 per person has been used and misused in many subsequent studies of air pollution costs. The highly publicized value of $65 per person for the total national cost of air pollution has been arrived at by simply inflating the Mellon result by the cost-of-living increase since 1913, and the often used national cost of \$11 billion to \$15 billion is this figure multiplied by the United States population, with an additional inflation factor sometimes applied to update the \$65 per person value.

Obviously, the projection of the 1913 Mellon result to a current national estimate for all air pollution damage is completely unwarranted. More recently, several more detailed studies have been conducted in order to arrive at estimates for the national cost of air pollution damage. Ridker[14] published a book on the economic costs of air pollution, which included consideration of costs due to health effects, soiling, materials damage, esthetics, and property values. He projected that the total cost of air pollution in 1970 would be between \$7.3 billion and \$8.9 billion. The 1968 total cost has been estimated at \$8.1 billion. More recently, Barrett and Waddell[23] reported a survey of the pertinent literature up to that time and arrived at a total national cost of \$16.1 billion for air pollution damage to health, property values, materials and vegetation. They went on to assign these costs to the various pollutants according to their relative tonnage of emissions. For example, of the \$6.06 billion in total health costs, they assigned costs to SO_2 and particulates solely on the basis of their relative emissions, and since SO_2 accounts for 54% of the total emissions of SO_2 and particulates combined, the conclusion was drawn that SO_2 alone causes \$3.272 billion in health damage. This conclusion is based on two incorrect assumptions: 1) that air pollution damage to health is due to SO_2 and particulates alone and 2) that the toxicity of SO_2 and particulates are the same. Both of these assumptions are without justification.

The assignment of damage solely on the basis of tonnages of emissions is unjustified because differences in toxicity and exposure are not taken into account. Clearly, an approach which accounts for these differences is needed to arrive at reliable estimates of total air pollution damage by specific pollutants. In order to apportion costs among the separate pollutants, nationwide total costs for air pollution damage to health, materials, plants, animals, and reduction in visibility are developed from a survey of the latest literature on these costs.

A method has been developed by which the costs of air pollution damage are evaluated from the exceedence of damage thresholds and the application of severity factors for each pollutant-effect interaction. The damage thresholds were assumed to be the air quality standards, since accurate thresholds have not yet been determined. Total annual damage cost estimates for each of five pollutants are: Particulates - from \$1.0 billion to \$4.7 billion, surphur dioxide - from \$0.3 billion to \$1.7 billion nitrogen dioxide - \$0.1 billion to \$0.5 billion, oxidants - \$0.5 billion to \$1.5 billion, carbon monoxide - \$0.06 billion to \$0.3 billion; for a total 1970 nationwide air pollution cost of from \$2.0 billion to \$8.7 billion[5].

Control

One set of emission regulations (for Georgia) based on using tall stacks for SO_2 control is described as follows:

SO_2 emissions from any source is restricted to a value of $400F\,(h_s/300)^3$ pounds per hour for sources with weighted average stack heights (h_s) less than 300 feet and to $400F\,(h_s/300)^2$ pounds per hour for sources with stack heights h_s greater than 300 feet. The factor F is taken to be 1 for urban fuel burning sources and all other kinds of sources, 0.8 when 2 or more fuel burning sources have a heat input of more than 500 million BTU/hour and which burn fuel containing more than 1 percent sulphur are located in an urban area, 2 for rural fuel burning sources having a heat input less than 10,000 million BTU/hour, and 3 for rural fuel burning sources with a heat input greater than 10,000 million BTU/hour. A source is considered to be urban if it is located within 5 miles of a city with a population of 50,000 or more. Similar stack height dependent emission regulations were also applied for particulates, to be applied in addition to the restriction by the boiler curve or process weight rate chart. The SO_2 emission regulations, when tested under 1975 projected conditions, were found to successfully attain the state SO_2 ambient air quality standard (43 $\mu g/m^3$ annual mean), which is more restrictive than the Federal secondary air quality standard (60 $\mu g/m^3$ annual mean). The annual air quality standard for particulates and the short term SO_2 and particulate air quality standards, as estimated by the AQDM statistical model, were also found to be achieved satisfactorily.

As the Georgia SO_2 emission regulations are constructed, a source which is not in compliance with the regulations (and which does not burn more than 3% sulphur fuel), can come into compliance by four alternative methods; using lower sulphur fuel, installing SO_2 scrubbing equipment, constructing a taller stack, or a mixture of SO_2 reduction and taller stack. The present SO_2 regulations are formulated entirely in terms of the stack height dependent emission regulations, however additional regulations in the form of boiler curves and process weight rate charts for SO_2 can also be developed as soon as the uncertainties of SO_2 removal equipment or availability of low sulphur fuel are adequately resolved.

The stack height dependent emission regulations for the State of Georgia are unique, but in view of the lack of acceptable alternate control measures to achieve the air quality standards on schedule, were considered to be necessary. Engdahl, in a critical review commissioned by the Board of Directors of the Air Pollution Control Association, considered the various possible SO_2 control strategies and concluded that "While it is recognized that the ultimate aim of the current regulations is to limit the overall emission of SO_2 into the atmosphere, the immediate goal is to assure that ambient air quality standards are attained. In view of the lack of proven methods or processes for removing SO_2 from flue gases, explicit consideration should be given to encouraging the use of tall stacks, where appropriate, as an interim approach to help reduce the ground level concentration of SO_2." Engdahl further states, "Judging from the failure of supposedly promising SO_2 removal processes in recent years, many of the current experiments can also be expected to fail. This is the nature of research .... Meanwhile, tall stacks have been shown both here and abroad to be effective in reducing the concentration of SO_2 in the vicinity of large plants, and the public will be benefited if tall stacks are encouraged as an interim measure until reliable removal processes are available."

A primary factor influencing the decision to utilize a stack height related standard to meet ambient standards was the necessity of achieving this goal by mid-1975. The State of Georgia feels, as do others, that there are sound reasons to prefer actual reduction of SO_2 emissions. This is presently accomplished by limiting the sulphur content of fuels, based on boiler input capacity. When the use of SO_2 removal devices and/or fuel desulfurization methods are reasonably proven and available, the use of such technology is to be considered and put to use where needed or beneficial. In the meantime, use of tall stacks is a method proven effective in achieving air quality standards. When removal devices are added at later dates, the existing tall stack will allow continued air quality improvements, and a minimum acceptable air quality even during removal equipment breakdowns and adverse meteorological conditions.

The Georgia SO_2 emission regulations have been subjected to further diffusion analysis by the PEDCO Corporation (under EPA sponsorship), and it was confirmed that compliance with the Georgia SO_2 emission regulations would insure attainment of the air quality standards. However, the legal status of the Georgia tall stack standard is somewhat uncertain, since it is currently being challenged in court by the Natural Resources Defense Council (NRDC). The position of the courts is also unclear. In the "Findings of Fact" in the case of Commonwealth of Pennsylvania vs. Pennsylvania Power Company (Case No. 2 - 1972 - Equity, in the Common Pleas Court of Lawrence County, Pa.), the court stated that "The utilization of high stack technology as a method to improve ambient air quality, which is the ultimate goal of Pennsylvania's regulations, has demonstrated value." On the other hand, several other legal actions with regard to SO_2 compliance to regulations which would require SO_2 scrubbing, as summarized by Snyder (1973), have ended with varying results: compliance being required, complaince being postponed, or no action being taken.

The alternative to using tall stacks to meet the air quality criteria on schedule may well be to postpone achieving the air quality standard. The Industrial Gas Cleaning Institute submitted to EPA hearings a statement concerning the achievability of the SO_x compliance schedules through the use of SO_2 scrubbing equipment. The statement said in part: "In view of the practical design, manufacturing and construction problems, the proposed (SO_x compliance) schedules cannot be met. The final compliance should be set back until at least July 1,1980 and compliance should be on a staggered basis." The official position of EPA as handed down in its "supplementary controls" policy is to revoke the annual SO_2 secondary air quality standard and to allow selective use of air-dispersion procedures to control pollution from industrial sources threatened with shut-down because of air quality standards. The new supplementary controls proposal would ban the use of tall stacks, beyond those considered "good engineering practice," as a control strategy, and defines "reasonable time" for meeting primary ambient air standards called for in the clean Air Act as the time required to design, fabricate, and install "reasonably available control technology."

These actions which delay the attainment of the primary and secondary air quality standards have been brought about or worsened by the present energy crisis, with its resultant shortages of low sulphur fuel. In contrast, the tall stack standard in Georgia has meant that the decreased supply of low sulphur fuels has resulted in little or no change in the compliance schedules for SO_2 sources in Georgia, and the primary and secondary air quality standards will still be met on schedule by 1975. Since the Georgia regulations allow power plants to burn coal with up to 3% sulphur, the citizens of Georgia will continue to have an adequate supply of power. Most states have more restrictive regulations which result in a shortage of electric power since high sulphur coal cannot be burned.