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Coal Gasification for Electric Power Generation

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The electric utility industry in the United States is facing an extremely critical period in the last two decades of this century. A sluggish U.S. economy, recent conservation measures, and rapidly rising electricity rates have resulted in a sharp decrease in load growth projections for most U.S. electric utilities. Capacity additions of nuclear and coal power plants are typically 750 to 1300 megawatts electric, with individual plant costs equal to the entire book value of many utilities. With the addition of severe licensing and emission control requirements on these plants, many utilities are at the brink of financial disaster.

Summary. The electric utility industry is being severely affected by rapidly escalating gas and oil prices, restrictive environmental and licensing regulations, and an extremely tight money market. Integrated coal gasification combined cycle (IGCC) power plants have the potential to be economically competitive with present commercial coal-fired power plants while satisfying stringent emission control requirements. The current status of gasification technology is discussed and the critical importance of the 100-megawatt Cool Water IGCC demonstration program is emphasized.

Although no one technology will correct this problem, there is clearly a need for new power plants with the following characteristics: (i) modular capacity increments of 100 to 300 MWe, (ii) design-to-construction lead times of less than 5 years, (iii) systems capable of utilizing all U.S. coal types and satisfying stringent emission control requirements, (iv) high plant availability, (v) economic competitiveness with present commercial power plants, and (vi) promise of significantly increased performance as the technology becomes mature.

Integrated coal gasification combined cycle (IGCC) power plants using second-generation gasification technologies show promise of meeting these requirements. It is projected that these advanced systems can be brought to technical readiness by the middle 1980's, with initial commercial plants in the late 1980's to early 1990's. The electric utility industry recognizes the potential for these systems and supports an intensive research, development, and demonstration program to determine whether this potential can be realized. For example, the Electric Power Research Institute (EPRI) and the U.S. electric power industry are contributing up to $160 million toward the 100-MWe Cool Water coal gasification demonstration plant to be constructed near Barstow, California (*1*). This plant will demonstrate one of the promising second-generation gasification technologies, namely the Texaco partial oxidation process, integrated with a slightly modified General Electric combustion turbine combined cycle plant. The plant is designed to meet environmental requirements and, we believe, will be the forerunner of a whole new class of power generation systems using a wide range of domestically available coals.

Historical Development and Current Status of Gasification Technology

The gasification of coal is an old practice which was extensively used in the United States before the 1950's. It ceased to represent a technology of commercial interest after World War II, when the availability of low-cost petroleum and natural gas and the installation of pipeline transmission and distribution systems resulted in the shutdown and retirement of coal gasification plants for economic reasons. In the 1920's there were 11,000 gasifiers in the United States producing gaseous fuels. Several thousand such plants were still operating and supplying fuel to domestic, commercial, and industrial users in the 1940's. These plants were relatively inefficient, low-pressure, low-capacity producer gas sets. Today they would be considered economically and environmentally unacceptable. At the turn of the century the electricity industry in the United States, France, and Germany used gaseous fuel from coal to power primitive gas engines. However, coal combustion coupled with the steam turbine, which was derived from marine applications, superseded the use of coal-based gaseous fuels for producing electricity.

Three major types of gasification processes have been or are now under development: the moving bed (sometimes referred to as the fixed bed) gasifier, the fluidized bed gasifier, and the entrained gasifier. Key features of these three coal gasification reactor types are compared in Table 1. Entrained flow gasifiers have the most desirable performance in terms of unit capacity, coal feed flexibility, and absence of tars in the product gas. The price for this is higher operating temperatures in the gasifier, with attendant risk of short reactor lifetimes and poor "cold gas" efficiency. (Cold gas efficiency is the ratio of the chemical energy in the product fuel gas to the chemical energy in the coal feed; it does not

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include the sensible or latent heat content of the fuel gas.) The slagging moving bed gasifier is a very close competitor, and if such gasifiers can handle caking coals at throughputs of 800 to 1000 tons per day (*2*), they may become a viable economic choice for bituminous coals.

Examples of these three types of gasification systems have been available for many years on a commercial scale. Large-scale moving bed gasification technology is offered by Lurgi Kohle and Mineröl-Technik of the Federal Republic of Germany. The equipment operates at an elevated pressure, uses a sized coal, and can be blown with either air or oxygen. Such equipment is in operation abroad and can generally convert noncaking coals (for instance, lignite and subbituminous coal) efficiently to synthesis gas. The largest concentration of moving bed Lurgi gasifiers (49 gasifiers handling 19 million tons of coal per year) is in South Africa, where the synthesis gas is used for producing fuels and chemicals (SASOL) (*3*). Disadvantages associated with Lurgi gasifiers are their production of by-product tars, which poses potential environmental problems; high steam consumption, representing an economic penalty; and inability to consume large quantities of coal fines, resulting in potential disposal, environmental, and economic penalties.

Commercial fluidized bed gasification technology is represented by the Winkler process, which was first applied in Germany in the 1920's for the production of gaseous fuels and feedstocks for industrial chemicals. Disadvantages of this technology are its inability to feed ground coal reliably at high pressure and inability to consume all of the coal fed to the reactor, resulting in environmental and economic penalties. Further, it has not been shown to be capable of handling caking bituminous coals.

The Koppers-Totzek process is an example of an oxygen-blown, entrained coal gasification process that operates at atmospheric pressure. It is commercially offered and applied, generally for the production of industrial chemicals, outside the United States. A feature of entrained systems is their ability to handle a wide variety of coals with caking and noncaking properties. The Koppers-Totzek process has the disadvantages that its low-pressure operation results in economic penalties associated with the requirement to pressurize the synthesis gas produced, and its use at extremely high temperatures results in potential refractory problems and reduced reliability of operation.

Commercial application of these coal gasification processes in the United States is being considered for plants that could supply clean gaseous fuels. Examples of such projects are a lignite-fed Lurgi-type plant under design by Exxon U.S.A., a Lurgi-type synthetic natural gas (SNG) plant considered by American National Resources, and a Koppers-Totzek–type plant planned by the Tennessee Valley Authority. Such plants represent relatively low-risk ventures since they would be based on foreign commercial practice that is adapted to U.S. coals with designs that meet more stringent environmental regulations. For specific coal types (such as lignites) and for site-specific conditions, currently available technologies may represent the economic choice with the lowest project risk.

Many advanced gasification concepts are currently being developed on the laboratory scale. They will require many years of effort and expenditures in the range of $200 million to $500 million before they can be considered commercially acceptable. Units that are now in the construction or operational stage at capacities exceeding 100 tons of coal per day are considered to be second-generation technologies. Table 2 summarizes the status of these second-generation coal gasification devices. If these large-scale pilot plants prove to be successful (as some of them already have), they still need to be demonstrated at approximately 1000 tons per day before they can be considered potential competitors in the commercial market.

Table 1. Comparison of coal gasification reactor types.

Function	Moving bed		Fluidized bed	Entrained flow
	Dry ash	Slagging		
Capacity potential	Low	High	Intermediate	High
Ability to handle caking coals without pretreatment	Moderate	Shown at 300-ton-per-day scale	Shown on small scale	Excellent
Temperature of operation	1100°–450°C	1550°–450°C	870°–1050°C	1650°–950°C
Temperature control	Poor	Poor	Good	Moderate
Refractory problems	Moderate	Poor	Moderate	Poor
By-product tar formation	Yes	Yes	Possibly	Probably not
Ability to extract ash low in carbon	Moderate	Good	Moderate	Good
Ability to consume fine carbon particles	Poor	Good	Probably poor	Good

Table 2. Status of second-generation coal gasification technologies (capacity greater than 100 tons per day).

Technology	Type	Plant capacity (ton/day)	Plant location	Product	Status
Texaco	Entrained	165	Oberhausen, West Germany	Gaseous fuel, synthesis gas	Operational
	Entrained	150	Muscle Shoals, Alabama	Synthesis gas, fertilizer	Start-up
	Entrained	150	Plaquemine, Louisiana	Gaseous fuel, electricity	Operational
Shell	Entrained	150	Harburg, West Germany	Gaseous fuel, synthesis gas	Operational
Combustion Engineering	Entrained	120	Windsor, Connecticut	Gaseous fuel	Operational
British Gas/Lurgi	Moving bed–slagging	350	Westfield, Scotland	Gaseous fuel	Operational
British Gas/Lurgi	Moving bed–slagging	700–800	Westfield, Scotland	Gaseous fuel	Construction, operation 1982
KilnGas	Rotating kiln	600	Wood River, Illinois	Gaseous fuel	Construction, operation 1982
Lurgi	Moving bed (high pressure)	175	Dorsten, West Germany	SNG, fuel gas	Operational
Saarberg-Otto	Entrained-slag bath	250	Volkingen, West Germany	SNG, fuel gas	Operational

Coal Gasification for Electric Power Generation

Our major objective in this article is to discuss the incentives for the development of IGCC systems for electric power generation. Other applications of coal gasification in the electric utility industry will be summarized later.

It is important to understand that there are a number of key differences in desired product gas characteristics between SNG production and electric power production. In the case of SNG it is desirable to maximize methane and hydrogen production and the moisture content of the synthetic gas, whereas for electric power production carbon monoxide is the desired dominant gas constituent and high-temperature operation, which precludes tar formation, produces this type of gas. (See Table 3 for typical gas compositions.) In addition, a high sensible heat content in the synthetic gas is acceptable for electric power production since it can be used to produce steam, which can be integrated into the steam bottoming portion of a combined cycle power plant. In other words, cold gas efficiency is extremely important for SNG production, but the overall heat rate (coal to busbar) is the proper measure of performance for IGCC power plants. Finally, either oxygen- or air-blown gasifiers are acceptable for electric power production, whereas only oxygen-blown systems are acceptable for SNG production. However, the technical development of oxygen-blown systems is more advanced, and they are therefore preferred for the initial second-generation IGCC demonstration plants and commercial modules.

Table 3. Typical gas composition; values are percentages by volume except for the last two rows.

Component	Moving bed, Lurgi oxygen-blown	Fluidized bed, Westinghouse	Entrained: Texaco oxygen-blown	Entrained: Combustion Engineering air-blown
CH_4	4.2	7.2	0.3	1
C_2^+	0.5			
H_2	21	29	29.6	9
CO	8	43	41	16
CO_2	15	6	10	6
H_2S + COS	0.7	1	1.1	< 1
N_2	0.2	1.5	0.8	62
NH_3	0.4	0.3	0.2	
H_2O	50	12	17	5
Tars and oils (weight fraction)	0.02	0.0	0.0	0.0
Temperature (°C)	540	985	1315	985

Environmental Considerations

IGCC systems are potentially uniquely capable of satisfying stringent environmental control requirements (*4*). This is extremely important, since these requirements can have a major impact on the cost of and ability to site a new coal-fueled power plant. All new power plants are required to comply with the 1979 Federal New Source Performance Standards (NSPS). In addition, many states and local communities impose environmental control requirements on new plants that are more stringent than the NSPS. Finally, in a growing number of locations in the United States new power plants must comply with stricter federal requirements such as BACT and LAER (best available control technology and lowest available emission requirements). Such requirements make it extremely costly and sometimes impossible for utility companies to site new coal-fired units. It is in this area of environmental control that IGCC systems should be most advantageous to the utility industry and the public at large.

In the process of gasifying coal, essentially all the sulfur in the coal is converted to hydrogen sulfide. The hydrogen sulfide can be removed from the raw fuel gas by any one of a number of commercially proven, regenerable, low-temperature, liquid absorption systems (for instance, Selexol, Rectisol, Sulfinol, Benfield, and ADIP). These processes, which operate at large scale today, can remove essentially all the hydrogen sulfide from a gas stream at relatively low cost. For example, the hydrogen sulfide produced by the Lurgi gasifiers at the SASOL II plant in South Africa is removed to the extent that the clean intermediate-Btu gas has a sulfur content less than 1 part per million. This level of sulfur removal is necessary to protect the Fischer-Tropsch synthesis catalyst. It is cheaper and more efficient to remove sulfur compounds from gasified coal than from the flue gas from conventional coal-fired plants for two reasons. First, sulfur removal in gasification is accomplished before the total combustion process has been completed. Second, it is accomplished at high pressure (300 to 600 pounds per square inch) in the absence of nitrogen. The net result is that the volume of gas to be desulfurized in a gasification system is only 0.7 percent of the volume of flue gas from a conventional coal-fired steam plant which must be scrubbed, in its entirety, for sulfur dioxide removal.

In addition, IGCC systems are as effective for particulate removal as they are for sulfur removal. After it has been cooled, the particulate-containing gas produced in the gasifier is scrubbed with water at high pressure to remove essentially all solid particles. Actual operating experience with gasification systems shows that it is not uncommon to produce a scrubbed gas with a particulate content less than 100 micrograms per cubic meter. This results in a particulate concentration in the stack gases from an IGCC plant that is at least 1000 times lower than that required by the NSPS.

Nitrogen oxide (NO_x) emissions in an IGCC system would be controlled by two different procedures. The first source of NO_x is the oxidation of fuel-bound nitrogen compounds during combustion. In coal gasification some of the nitrogen in the coal is converted to ammonia. This ammonia can be totally removed from the fuel gas prior to combustion by standard water scrubbing procedures, with the result that the clean gas fired to the gas turbine contains no fuel-bound nitrogen compounds. The other source of NO_x is the fixation of atmospheric nitrogen due to the high temperature of the combustion process. Experimental evidence indicates that such thermal NO_x generation can be controlled in a gas turbine by using specially designed (premix) combustors, or by injecting steam or water into the flame zone to moderate the temperature.

Of growing importance and concern is the ability to dispose of solid wastes from power plants in compliance with Resource Conservation and Recovery Act (RCRA) requirements. Currently available conventional coal-fired steam plants with limestone slurry scrubbers have to dispose of all the coal ash plus approximately 0.3 ton of sludge per ton of coal burned. (This is equivalent to a sludge disposal rate of more than 3000 tons per day from a 1000 MWe plant burning a high-sulfur coal.) IGCC systems produce no scrubber sludge for disposal. The major solid effluent from a gasification-based system would be the coal ash. Leaching tests on the ash produced in the Texaco gasification pilot plant in Montebello, California, as well as ash from the 150-ton-per-day Texaco gasifier in Oberhausen, West Germany, provide evidence that the leachates will meet federal drinking water standards and the ash products will contain no polynuclear aromatic materials.

Finally, the resource conservation potential of IGCC systems provides an additional incentive for the development and deployment of this technology for electric power generation. (i) IGCC plants will consume approximately 60 percent of the water required by a coal-fired steam plant as only 50 percent of the power is generated by the steam cycle; this greatly reduces cooling tower makeup requirements. (ii) The land required by IGCC plants is 30 to 50 percent of that required by conventional coal-fired plants, primarily because large sludge storage and disposal areas are not needed. (iii) IGCC plants will consume approximately 10 percent less coal than conventional plants with the same generating capacity, as they can be considerably more efficient than the pulverized coal plants with stack gas scrubbers. (iv) IGCC plants also do not require lime or limestone for sulfur removal. Table 4 summarizes the potential for resource conservation of a 1000-MWe IGCC power plant with respect to an equivalent conventional coal-fired steam system with limestone slurry scrubbers burning high-sulfur eastern coal.

Table 4. Resource conservation potential for IGCC systems with respect to conventional coal-fired steam plant with flue gas desulfurization.

Resource	Potential conservation*
Coal	225,000 tons per year
Water	1 billion to 2 billion gallons per year
Limestone	500,000 tons per year
Lime	30,000 tons per year
Land	~ 300 acres

*Based on 1000-MWe capacity, nonregenerable flue gas desulfurization, wet cooling towers, and high-sulfur (3.5 to 4 percent) coal.

Economic Incentives

Before considering the enormous cost of developing any new technology, it is prudent to evaluate whether the technology offers potential economic benefits over current systems. The Advanced Power Systems Division of EPRI has been conducting engineering and economic assessments of IGCC systems for the past 6 years. The major conclusion from these assessments (5) is that IGCC systems with current gas turbines (firing temperature, 1090°C) can be more efficient than and economically competitive with conventional coal-fired steam plants with flue gas desulfurization (6, 7).

As an example, we present performance and cost comparisons for a 1000-MWe oxygen-blown Texaco-based IGCC system and two 500-MWe conventional coal-fired steam plants with limestone slurry scrubbers (6). Figure 1 is a simplified block flow diagram of the Texaco-based IGCC plant under consideration. Hot, particulate-laden fuel gas leaving the gasifier at 1260° to 1430°C is cooled to approximately 200°C in a series of heat exchangers that raise high-pressure saturated steam. This steam is superheated in the heat recovery steam generator section of the combined cycle plant before being sent to the steam turbine generator. The fuel gas at 200°C is water-scrubbed to remove all particulate matter before being further cooled to 38°C. At this temperature, the gas is water-scrubbed for ammonia removal and is then sent to the hydrogen sulfide removal system. Acid gas from the hydrogen sulfide absorbers is sent to a Claus plant followed by a Beavon-Stretford tail gas unit, both of which recover high-grade elemental sulfur. The desulfurized fuel gas is reheated to 316°C in the raw gas coolers before being combusted in the gas turbine combined cycle power system.

Both the IGCC plant and the coal-fired steam plant were designed to meet the environmental control requirements of the NSPS plus a set of more stringent control requirements that could exist in the middle to late 1980's. These requirements are outlined in Table 5. (Some areas in the United States already require new coal-fired power plants to meet standards similar to the projected mid-1980 control requirements shown in Table 5.) The economic criteria used for the financial analyses are outlined in (6). Performance, capital requirements, and cost of electricity comparisons for the two systems evaluated are summarized in Table 6. The cost estimates generated for the IGCC plants do not represent anticipated costs for first-of-a-kind systems; they represent what can be expected for mature systems—that is, approximately the fifth large plant to be constructed.

The results in Table 6 illustrate the economic incentives for IGCC systems. Under current federal emission control requirements, the Texaco-based IGCC plants are projected to be more efficient than their coal-fired counterparts (heat rate is inversely proportional to thermal efficiency). The IGCC systems will require essentially the same capital for construction, and electricity costs will at least be competitive with those of present coal-fired plants. With more stringent environmental control regulations, the capital and operating costs for the IGCC system are substantially lower than those for the coal-fired steam plant, resulting in a potential 20 to 25 percent decrease in the cost of power generated.

Improvements in gasifier and gas turbine technology should result in cost reductions that offset increases due to more stringent environmental regulations. For conventional coal-fired plants, on the other hand, costs can be expected to increase steadily if environmental regulations become tighter, resulting in a widening differential between the two coal-based systems (7).

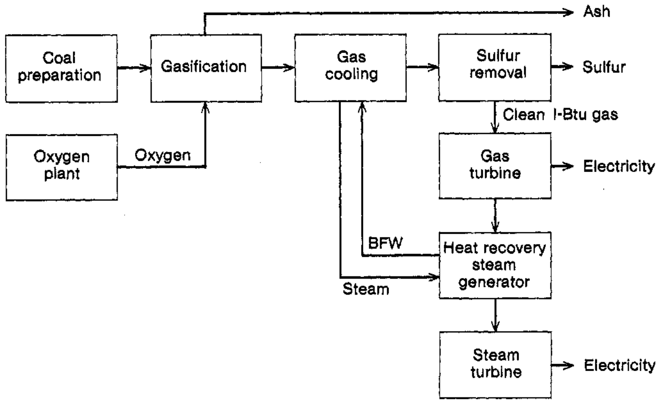

Fig. 1. Integrated gasification combined cycle system. *BFW*, boiler feedwater.

Power Plant Reliability

In most performance comparisons of new power plants, the major quantitative figures of merit are power plant heat rate and capital cost. The EPRI evaluation of IGCC systems has convinced us that reliability, or availability, is an equally important quantitative factor from the standpoints of both design and operations and maintenance. Over the past 3 years we have developed the methodology and initial data base on plant components, controls, and accessories for IGCC plants. Where data were lacking, we performed a wide range of sensitivity analyses to evaluate component or subsystem importance in the overall plant operation.

This approach was applied to the analysis of a 1000-MWe IGCC plant (Fig. 1) having five parallel gasification trains (plus spare), three sulfur removal trains, seven combustion turbines and heat recovery steam generators, and one steam turbine. The analyses indicate that such a plant should achieve 80 to 85 percent equivalent availability, based on the available information on failure rate, the mean time to restore components, and a well-organized and stocked inventory of spare parts.

Importance of the Cool Water Project

We have already pointed out the potential environmental and economic benefits of the use of IGCC technology for electric power generation. It is important to realize that all of these benefits are conjectural and are contingent on the fact that IGCC systems will operate in the anticipated mode. An IGCC of the type described here has not been built or operated at any significant scale anywhere in the world. All of the Texaco-based system designs and cost estimates presented here and elsewhere are based on large-scale commercial experience for most of the subsystems contained in the plant. Major unknown factors, however, still remain to be demonstrated before all the cost and performance estimates can be considered firm. These factors are outlined below:

1) The Texaco gasification system fed with coal has been shown to operate at the scale of 150 to 200 tons per day. Before the utility industry can consider purchasing Texaco-based IGCC plants for power generation, the Texaco gasification system must be demonstrated to be reliable and operable at larger capacities—at least 1000 tons per day.

2) Most of the subsystems contained in any IGCC plant have been proved for many years at commercial scale. However, it has never been demonstrated that they can perform reliably and economically when linked together and operated in the dynamic manner required of most power plants. Mathematical models of Texaco-based IGCC systems indicate that such power plants will be able to operate in a variety of load-following modes. However, such models only provide an indication of the capabilities of these systems. Only long-term operation of a large IGCC plant will convince the utility industry that such systems can be built to meet their needs.

3) It has yet to be demonstrated at full scale that can-type combustors for gas turbines can be designed to burn intermediate-Btu fuel gas in a reliable and environmentally acceptable manner.

These concerns will be alleviated only after a large-scale (~100 MWe) IGCC system has been successfully operated for at least 2 years. This will provide—at full commercial scale—information on reliability, materials, controllability, environmental acceptability, and performance for a large spectrum of coal types. With this information the electric utility industry will be able to decide whether such systems can be employed to produce electric power in a cost-effective and environmentally acceptable manner.

To this end, Southern California Edison Company, EPRI, Texaco Inc., General Electric Co., Bechtel, JCWP (a consortium of four Japanese companies: Tokyo Electric Power Company, Central

Table 5. Emission control requirements used in comparison of IGCC and conventional coal-fired steam plants.

Item controlled	Emission control requirements: 1979 federal NSPS	Emission control requirements: Projected mid-1980's standards
Sulfur removal (percent)	90	95
Particulates (pounds per 10^6 Btu's)	0.03	0.02
NO_x (pounds per 10^6 Btu's)	0.6	0.2
Waste water		Zero discharge
Coal ash		Special handling

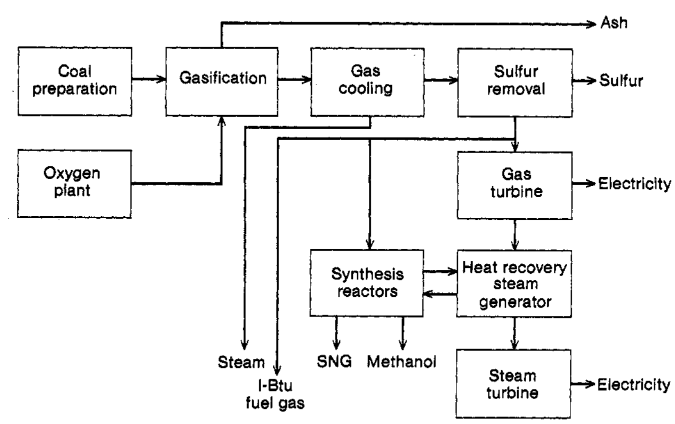

Fig. 2 Gasification for coproduction.

Table 6. Economic comparison of IGCC power systems with conventional coal-fired steam plants under two sets of emission control requirements.*

Plant type and item compared	Emission control requirements: 1979 federal NSPS	Emission control requirements: Projected mid-1980's standards
Coal-fired steam plants		
Heat rate (Btu's per kilowatt-hour)	9,980.0	10,050.0
Capital requirement (dollars per kilowatt)	880.0	1,160.0
30-year levelized cost of electricity (mills per kilowatt-hour)	56.3	68.0
IGCC plant with 2000°F turbine		
Heat rate (Btu's per kilowatt-hour)	9,400.0	9,550.0
Capital requirement (dollars per kilowatt)	850.0	890.0
30-year levelized cost of electricity (mills per kilowatt-hour)	50.5	52.3

*The comparison was made on the basis of mid-1978 dollars, high-sulfur Illinois coal, and a coal cost of $1 per 10^6 Btu's.

Table 7. Electric industry use of coal gasification: selected projects.

Company	Project	Technology	Status
Central Maine Power	IGCC	Texaco	Design
Tennessee Valley Authority	Gaseous fuel	Koppers-Totzek	Design, test program in commercial plant
Arkansas Power and Light	Combined cycle cogeneration, gaseous fuel, steam	Texaco	Design study
Boston Edison	Gaseous fuel	BGC/Lurgi	Design study
Pacific Gas and Electric	Gaseous fuel, steam	Texaco	Feasibility study
Southern California Edison	IGCC, methanol	Texaco	Feasibility studies
Illinois Power Consortium	Gaseous fuel for electricity	Allis Chalmers KilnGas	Construction
Southern California Edison–Cool Water Consortium	IGCC	Texaco	Detailed engineering and construction
Gulf States	Gaseous fuel, retrofit	Combustion Engineering, Westinghouse	Design
Florida Power	Repower, retrofit	BGC/Lurgi	Design study

Research Institute of Electric Power Industry, Toshiba CGP Corp., and IHI Coal Gasification Project Corp.), and Empire State Electric Energy Research Co. (a group of New York State utilities) have become joint participants in the Cool Water demonstration program (*1*, *8*). The primary objective of this project is to construct and operate a 100-MWe IGCC power plant at Barstow, using Texaco's coal gasification technology and a modified General Electric gas turbine combined cycle power plant. Detailed engineering for this project is approximately 50 percent complete and hardware procurement and construction are under way. Without such a demonstration plant the introduction of this technology would be delayed indefinitely.

Other Potential Utility Applications of Coal Gasification

Our main objective in this article has been to point out the incentives for the application of IGCC technology to electric power generation. It should also be mentioned that coal gasification technology presents the electric utility industry with a wide range of interesting options for applications. This flexibility is due to the fact that oxygen-blown gasifiers produce a combination of synthesis gas (hydrogen and carbon monoxide) and heat (which can be converted into steam). The synthesis gas can be burned directly as a clean fuel, or it can be catalytically converted into other products such as SNG or methanol, which could be employed for power generation.

Figure 2 shows a variety of products that could be produced or coproduced in a gasification-based system. Some examples of these applications are:

1) Production of clean, intermediate-Btu fuel gas to be delivered "over the fence" to refuel the existing 225,000 MWe of installed gas- and oil-fired capacity.

2) Coproduction, in the same clean fuel gas production facility, of steam to be sold to local industrial customers.

3) A gasification plant to coproduce combined cycle electric power and methanol. The methanol could be used by the utility to supply its internal needs for intermediate- and peak-load liquid fuel, or it could be sold on the open market.

This short list of potential applications shows that the development of coal gasification technology promises to contribute significantly to reestablishing the strength and financial integrity of the electric utility industry. The multiproduct capability of coal gasification systems has prompted a number of design studies by electric utility companies; a list of these projects, including their current status, is shown in Table 7. In conclusion, we consider that coal gasification power plants can become an extremely attractive option for the power industry in the 1990's. Our task now is to demonstrate that this potential can be realized.

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