

PART II

OVERVIEW OF CURRENT DOE COAL PROGRAMS

Coal Preparation, Coal-Liquid Mixtures, and Coalbed Methane Recovery

DOE programs addressed in this chapter—namely, coal preparation, coal-liquid mixtures, and coalbed methane recovery—currently constitute relatively minor components of the total DOE coal program. Brief descriptions of the technologies, the state of the art, and current programs are provided. The committee's findings are then presented, with emphasis on the future role of DOE programs vis-à-vis private sector activities, requirements for commercial technologies, links to other major DOE efforts such as power generation, and research opportunities.

COAL PREPARATION

Description of Technology

Coal preparation—or cleaning—is the removal of mineral matter from as-mined coal to produce clean coal, a quality-controlled product with a composition that adheres to specifications based primarily on environmental and combustion performance. Its primary purpose is to increase the quality and heating value (Btu/lb) of coal by lowering the level of sulfur and mineral constituents (ash). In most Eastern bituminous coals, roughly half to two-thirds of the sulfur occurs in a form that can be liberated by crushing and separated by mechanical processing. Western coals typically contain much lower levels of sulfur, have lower heating values and are not readily amenable to physical cleaning methods for sulfur reduction. All coals contain mineral matter that also can be removed through physical cleaning. Coal preparation as currently practiced in the coal industry involves four generic steps: characterization, liberation, separation, and disposition.

During characterization, the composition of the different-size raw coal particles is identified. The composition of the raw coal and the required clean coal specifications dictate the type of equipment that must be used to remove the mineral matter. Crushing liberates mineral matter. Complete liberation can only be approached by reducing the mined coal to very fine sizes, since particles containing both coal and mineral matter, called middlings, are also produced during crushing. Separation involves partitioning of the individual particles into their appropriate size groupings—coarse, intermediate, and fine fractions—and separating the mineral matter particles from the coal particles within each size fraction. Separation techniques for

larger-size raw coal particles generally depend on the relative density difference between the organic coal and inorganic mineral matter particles. Separation techniques for fine raw coal particles utilize the difference in the surface properties of the particles in water. Disposition is the dewatering and storage of the cleaned coal and the disposal of the mineral matter.

Development History

Coal preparation began simply as a means of controlling the size of raw coal, but mechanized mining led to mechanized cleaning and the subsequent evolution of coarse, intermediate, and fine coal cleaning defined in terms of raw coal particle size ranges. All coals for the metallurgical and export markets are beneficiated, as well as coals sold for other industrial purposes. For most of its history, the primary objective of steam coal cleaning has been to reduce ash levels rather than sulfur content. The introduction of environmental requirements in the 1970s increased the interest in more extensive cleaning of coal to remove larger amounts of sulfur. Today, fine coal (less than 0.5 mm) cleaning is being further subdivided. Coal quality specifications have become more restrictive as a result of environmental regulations and as the impact of coal quality on boiler operating problems, such as slagging and deposition on tubes, has become better understood.

Coal preparation technology was first developed for the European coal industry and was licensed as needed by American companies. Mineral processing technology was also adapted for coal preparation. Significant technology development was conducted by the U.S. steel industry, since the coal used as feedstock for coke is required to meet very stringent specifications, particularly for sulfur content. The U.S. Bureau of Mines established internationally recognized in-house expertise in coal cleaning; this effort was continued under the DOE at the Pittsburgh Energy Technology Center (PETC). As a result of the tightening of coal specifications to comply with environmental regulations, EPRI (Electric Power Research Institute) established a Clean Coal Testing Facility (spun off in 1994 as an independent company, CQ, Inc.). In addition, a number of states, including Pennsylvania, West Virginia, Illinois, Ohio, and Kentucky, established research programs to improve the quality of their coals. Some research on coal cleaning has also been conducted by those oil companies involved in coal production.

State of the Art

Coal preparation technologies are widely practiced by the coal industry. Recent R&D efforts (Feeley et al., 1994; Killmeyer et al., 1994; Hucko et al., 1994) have been aimed at developing processes that will further reduce both the sulfur and ash contents of coals. Coal cleaning techniques for the fine fractions also are now commercial. Many of these same techniques have been utilized to produce the very clean coals required for coal-liquid mixtures (see below). Sustained investigations into chemical and biological coal preparation techniques that remove organic as well as inorganic sulfur have not, however, produced any systems with a strong potential for commercialization, largely because of their high costs. Indeed, from the perspective of many coal users, the higher cost of coals subjected to advanced levels of

preparation makes them unattractive relative to naturally occurring coals with lower sulfur and ash contents. Furthermore, many of the advanced power and fuel systems are designed to be fuel flexible, so there are limited markets for highly cleaned coals in the power generation sector.

Current Programs

DOE currently performs or funds the majority of coal preparation R&D in the United States. This activity falls primarily within the Advanced Clean Fuels Research Program. The FY (fiscal year) 1994 program budget of \$11.3 million included \$4.6 million for work on technologies for producing premium fuels and removal of air toxic precursors; \$2.25 million for continued testing of high-efficiency processes; and \$4.1 million for continuation of in-house bench-scale and characterization research at PETC related to advanced physical and chemical cleaning concepts (DOE, 1994a). In addition to the direct funding of the coal preparation program, the AR&TD (advanced research and technology development) component of the DOE budget supports a number of closely allied programs of a more basic nature, such as the \$1.9 million program on the bioprocessing of coal for sulfur and nitrogen removal, which is part of DOE's Advanced Manufacturing Technology program. This program recently shifted its emphasis to the removal of SO_x and NO_x from combustion gases, rather than from coal.

For FY 1995, DOE has proposed a 52 percent reduction in funding for coal preparation, to a total of \$5.5 million. The main thrusts of the program include continued research on advanced physical coal cleaning methods to produce premium coal fuels very low in ash, sulfur and air toxic precursors at the proof-of-concept scale of technology development (\$2.6 million), and continued in-house research on bench-scale development of advanced cleaning concepts (\$2.0 million) and related studies (\$0.8 million). The AR&TD program on bioprocessing of coal would continue at its present level (\$1.9 million), with emphasis on involvement with small and emerging companies.

Technical Issues, Risks, and Opportunities

Current physical coal cleaning techniques cannot reduce the sulfur content of coal to the levels needed to comply with most environmental regulations. Although the inorganic sulfur component of coal can be removed with other mineral matter, the organic sulfur is chemically bonded to the coal and is not amenable to physical separation. Biological and chemical methods for sulfur removal so far have not been promising for commercial-scale application. Because coal is an abundant and relatively low cost fuel, the added cost of advanced preparation technology, combined with the cost of coal that is lost with separation process wastes, makes it extremely difficult for advanced cleaning methods to be economically competitive for applications involving direct coal use. The most promising applications for advanced beneficiation methods lie in the production of premium fuels that replace oil or gas (e.g., coal-liquid mixtures, discussed below). However, current and projected prices for oil and gas make it unlikely that significant markets for coal-based alternative fuels will emerge before the mid-term period. In the near term, however, coal preparation might prove a desirable technique for

selective treatment of coal to meet possible future hazardous air pollutant regulations by reducing trace element concentrations prior to combustion.

The utility industry is interested in promoting technical and economic improvements in coal beneficiation methods as an indirect means of reducing fuel-related costs. Lower-sulfur fuels provide better cost-benefit solutions for older boilers than scrubbers. Burning upgraded coal reduces the cost of maintaining boiler systems and increases combustion efficiency. SO_x reduction in the flue gas reduces scrubber costs where flue gas desulfurization (FGD) is needed. Achieving maximum energy recovery requires improved liberation, improved separation efficiency, total cleaning, and process control. Size reduction and thermal drying account for about 75 percent of the capital costs and 50 percent of the operating costs for processing coal. The challenge for coal cleaning is to deliver coal at a price that is economically competitive with other sources of coal of comparable quality. Thus, the markets for cleaned coals are highly dependent on site-specific factors.

There is an emerging global market for this segment of the U.S. coal industry, particularly in India, Poland, and China, which have large reserves of relatively low quality coal. Improved U.S. coal preparation technology would make the United States more competitive in the international coal technology market. Improving the technology, in some cases, requires more development. For example, commercial preparation is not currently economically optimized. There is a need for testing and verifying new technologies, performing unit operations analysis, developing instrumentation for process control, including computerized on-line analyzers, and improving dewatering for both fine high-rank coals as well as low rank coals. However, the R&D and demonstration planning should use market-based decision tools and have extensive industrial participation.

Findings

DOE has contributed to the development of the fine coal cleaning technology that is now commercially available. Applied research to improve current commercial preparation processes may help such technology compete more effectively, especially in international markets. Advanced power and fuel systems are being designed for fuel flexibility and high-efficiency sulfur removal and may be unlikely to require coals that have been subjected to coal preparation beyond current commercial practice.

Reduction of trace element concentrations in coal representing air toxic precursors may offer an R&D opportunity for meeting future, as yet undefined, hazardous air pollutant emission standards. Work in this area is addressed in the DOE's proposed program for FY 1995.

COAL-LIQUID MIXTURES

Background

Coal-liquid mixtures consist of finely ground coal suspended in a liquid, such as oil or water, together with small amounts of chemical additives to improve stability and other physical properties. The primary purpose of coal-liquid mixtures is to make solid coal behave as an essentially liquid fuel that can be transported, stored, and burned in a manner similar to heavy fuel oil. The most mature coal-liquid mixture technologies are those using coal-oil and coal-water mixtures (CWM). Several of these technologies already have been offered commercially. Since coal-liquid mixtures are intended as a substitute for oil, their market penetration is heavily dependent on oil prices.

Development History

Initial development work on coal-oil mixtures (COMs) dates back to the last century (DOE, 1988). Extensive COM research was conducted in the United States during the 1940s because of wartime constraints on oil supply. More recent interest in COMs followed the 1973 OPEC oil embargo and the oil price hikes of the late 1970s. Utility and industrial boiler demonstrations using COMs were conducted in the United States, Japan, Sweden, and England between 1977 and 1981. Over 20 COM preparation plants are currently operating or have been operated in various countries.

The first combustion tests of CWMs—also known as coal-water slurries (CWSs)—were conducted in the United States, Germany, and the former Soviet Union in the 1960s. There was active development of CWMs in the United States in the 1980s, with emphasis on developing technologies to prepare mixtures with desirable physical and chemical properties, demonstrating retrofit in existing boilers, and developing specialized equipment for handling and transporting slurries. During this period, a number of private companies were actively involved in, or planned to enter, the CWS business. All have subsequently gone out of business or abandoned commercialization of slurries as oil prices declined in the early 1980s.

State of the Art

Areas for further performance improvements in COMs depend on advanced coal beneficiation to further reduce sulfur and ash content and improved additives or other means of increasing the weight percentage of coal in the mixture. CWSs also are a potential alternative to premium fuels (oil and gas) being used in industrial and utility boilers and were offered commercially in the early 1980s. Cost studies suggest that slurries could be prepared and used economically with oil prices around \$25 to \$30/bbl, given a production facility of sufficient scale and the infrastructure required to handle the fuel. Such studies also indicate that slurries are economical if the differential in cost between heavy oil and slurry is \$1.50 per 10⁶ Btu (Addy and Considine, 1994). Present oil price forecasts, however, make it unlikely that coal-based

substitutes will be competitive in the near to mid term. Nevertheless, one Pennsylvania utility (Penelec) is currently investigating cofiring its pulverized coal utility boilers with a CWS to provide 20 to 40 percent of fuel needs (Battista et al., 1994). This technology would allow the utility to purchase and utilize fine upgraded coal while reducing NO_x emissions with no boiler derating.

Current Programs

Much of the current work on coal-liquid mixtures is being funded, at least in part, by DOE. Activities range from fundamental research on mixture preparation and properties, through bench-scale preparation and combustion, to commercial-scale demonstrations. The emphasis in all these programs is on CWSs rather than COMs.

Fundamental research on CWSs is being conducted at Adelphi University, Carnegie Mellon University, and Texas A&M University under the Coal Utilization Science program of DOE's AR&TD activity. Topics under investigation include the combustion system atomization processes, modeling, and measurement of viscosity and surface properties. The Pennsylvania State University is conducting a superclean CWS program with support from DOE and the commonwealth of Pennsylvania to determine the capability of firing such slurries in an industrial boiler designed for firing heavy fuel oils, with no adverse impact on boiler rating, maintenance, reliability, and availability. DOE, through the University of North Dakota Energy and Environmental Research Center, also is supporting the development of refuse-derived fuel/coal slurry fuels. DOE is managing a boiler conversion program at the Pennsylvania State University for the U.S. Department of Defense, with the objective of developing commercial CWS technology. The program will provide a military base with a commercially engineered CWS conversion system for firing its oil/gas-fired boilers.

Demonstration projects using CWS include a CCT (Clean Coal Technology) Round V program to demonstrate clean coal diesel technology. The diesel system will use a CWS produced from Ohio coal by a two-stage coal cleaning and slurring process. Another CCT program is demonstrating the combustion of injected coal in the tuyeres of two blast furnaces at Bethlehem Steel. Blast furnace coal injection technology, where granulated or pulverized coal is injected into a blast furnace in place of natural gas (or oil) as a fuel supplement or reductant to lower the coke rate and hot metal cost, may incorporate CWS technology in the future. A University of North Dakota project on power generation from an Alaskan coal-water fuel has demonstrated the preliminary process economics of a concentrated low-rank coal-water fuel. The second phase of the program is aimed at developing a low-cost indigenous replacement for the imported diesel fuel used in many native villages of the Alaskan interior.

While a specific breakdown of DOE funding for coal-liquid mixture R&D is not provided in the FY 1995 budget request, the overall funding for the AR&TD Coal Utilization Science program is projected to decrease from \$3.1 million in FY 1994 to \$2.2 million in FY 1995. Part of this decrease is due to a reallocation of some projects to other coal program budget lines. A more detailed discussion of DOE's advanced research budgets appears in Chapter 9.

Findings

COM and CWS technologies are either commercially available or on the verge of commercialization. Aside from some niche market opportunities, the private sector currently has little current interest in adopting these technologies. However, if oil or gas prices increase significantly above current or projected near-term levels, COMs are available for commercial application. At that time, there may be a need for programs that assist the private sector in taking CWS technology to the marketplace.

COALBED METHANE RECOVERY

Background

The coal formation process occurs when organic debris is converted to coal and various by-products, including water and methane (CH₄) gas. The latter may be found in the coal itself or trapped in the strata surrounding the coal. For every ton of coal formed, as much as 5,000 cubic feet of "coalbed methane" may be generated in situ (DOE, 1994b). Coalbed methane liberated into mine workings by underground coal mining can be a serious safety hazard, since methane is highly explosive in volume concentrations of 5 to 15 percent. Thus, underground mines in the United States are required to maintain methane concentrations below 1 percent of the concentration of the air in the mine (CFR, 1988).

Methane has attracted recent attention as a greenhouse gas that may contribute to global warming (see Chapter 3). The Clinton administration's Climate Change Action Plan (Clinton and Gore, 1993) identifies coal mines as one of the primary sources of methane emissions in the United States and requires the EPA (U.S. Environmental Protection Agency) and DOE to launch a coalbed methane outreach program to raise awareness of the potential for cost-effective emissions reductions with key coal companies and state agencies. In addition, the Climate Change Action Plan requires DOE to expand its research, development, and demonstration (RD&D) efforts to broaden the range of cost-effective technologies and practices for recovering methane associated with mining.

State of the Art

While all coal seams contain some methane, the highest levels of coalbed methane in the United States occur in seams in Virginia, West Virginia, Utah, and Colorado. To mine these gassy seams, mining companies have developed a number of techniques to eliminate or reduce the amount of methane liberated during mining. The primary technique is to design the mine ventilation system with enough capacity to keep the concentration at acceptable levels well below the lower explosive limit—generally less than 1 percent methane by volume. Other methods involve vertical drilling into the coal seam to vent methane before and after mining and drilling horizontally into the seam and venting the gas to the surface. There are instances where mining companies collect high-concentration methane and, after limited cleaning, sell the gas to a

commercial pipeline. The economics of collection and sale to a user or distributor can either be based on a direct payback basis or justified by a reduction in mine ventilation costs.

Current Programs

Section 1306 of EPACT requires DOE to study barriers to coalbed methane recovery, to assess environmental and safety aspects of flaring coalbed methane liberated from coal mines, and to disseminate information on state-of-the-art coalbed methane recovery techniques to the public. DOE is further required to establish a coalbed methane recovery demonstration and commercial application program, with emphasis on gas enrichment technology. DOE requested \$300,000 in the FY 1994 budget for coalbed methane activities, but that funding was not approved. The administration's FY 1995 budget request includes coalbed methane recovery activities in the natural gas portion of the Fossil Energy program. As required by the Climate Change Action Plan (see above), EPA recently launched an outreach program to encourage coal companies to install methane recovery equipment at mines across the United States. The goal of this program is to reduce methane emissions from coal mines by at least 500,000 metric tons (25 billion cubic feet) by 2000 (Wamsted, 1994). DOE has developed a plan to expand RD&D for methane recovery from coal mining; DOE and industry will cofund projects on a 50 percent cost-sharing basis. This activity will be coordinated with the EPA outreach program.

Issues, Risks, and Opportunities

Technology for the recovery of coalbed methane from gas streams with high methane concentrations is commercially available and practiced by the gas and mining industries where conditions justify the investment. However, the collection and sale of methane are not widespread in the coal mining industry because of a number of technical and commercial issues. These include ambiguities in mineral rights concerning gas ownership, trade-offs between the selling price of methane and tax credits to encourage investments, the dependence of methane recovery on gas concentration and porosity of the coal or strata, the quantity and quality of gas to be vented, and constraints on the underground mining technique used (e.g., room and pillar versus longwall).

Technology for the use or control of coalbed methane emissions in very dilute gas streams (methane concentration less than 1.0 percent) is not currently available. Low-quality mine gases must be upgraded or enriched for sale to a distribution system. In view of the importance of methane as a greenhouse gas (see Chapter 3), opportunities exist to encourage the utilization of dilute methane streams emitted from coal mines by developing relevant technologies.

Possible research areas include new techniques for methane separation and the combustion of very dilute methane streams. Separations of methane from dilute ventilation air by conventional methods is expensive and energy intensive. Research aimed at finding new materials for selective adsorption or selective diffusion through membranes is of interest (see Chapter 9). Ventilation air streams are too dilute to burn in conventional combustion equipment

without use of additional fuel, which would generate additional greenhouse gases. Catalytic combustion systems offer some promise, and advances made for other applications are of interest (see, for example, Haggin, 1994).

Findings

Coalbed methane recovery is a commercially available technology that is being practiced where concentrations are sufficiently high and where merited by the return on investment or benefits to mining.

Technologies for the capture and use of dilute coalbed methane streams are not sufficiently mature for commercial implementation. Given the increased emphasis on reducing emissions of greenhouse gases, including methane from coal mining, there are potential research opportunities directed toward the recovery of coalbed methane from very dilute gas streams.

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Clean Fuels and Specialty Products from Coal

Coal is currently a major source of fuel for power generation, industrial heat, and, on a smaller scale, manufacture of coke and by-product coal tar. In the mid to long term, anticipated increases in the cost of natural gas and petroleum relative to coal are expected to increase the incentive for expanded efforts to convert coal to ash-free, low-sulfur transportation fuels and, ultimately, gaseous fuels for domestic use (see Chapter 3). As natural gas prices increase, substitution of gas from coal in natural gas-fired power generation plants may become economic. Advanced combined-cycle and fuel cell power generation technologies will also require the conversion of coal to clean gaseous fuels. In addition to the above major uses, economical use of clean gaseous and liquid products from coal can provide a source of feedstock for chemicals production.

This chapter discusses the status of technologies for coal conversion to clean fuels and the role of the DOE in developing and promoting lower-cost, higher-efficiency processes to meet future needs. This discussion is divided into three major sections: gasification of coal, products from the gas obtained from coal gasification, and products from direct liquefaction and pyrolysis of coal.¹ Opportunities for economic production of a range of coal-based products using coproduct systems, also known as coal refineries, is then addressed. The chapter concludes with the committee's major findings relating to clean fuels and specialty products from coal.

GASIFICATION OF COAL

Background

Conversion of coal to a gaseous fuel that can be cleaned and used in homes and commercial installations has been practiced for over 200 years. It was a major industry in the United States and abroad until the 1940s. During World War II, the manufacture of liquid fuels was practiced by Germany to provide military fuel, and in this context significant advances were made in gasification technology that formed the basis for present-day gasifiers. The increasing

¹An extensive discussion of coal conversion technologies is provided in another National Research Council report on production technologies for liquid transportation fuels (NRC, 1990). The reader is referred to that report and the references therein for further details of conversion chemistry.

availability of natural gas and petroleum in the United States and other industrialized countries resulted in the replacement of coal-based town gas with natural gas or heating oil. The oil embargo of 1973 and predictions of impending natural gas shortages, however, resulted in major industry and government programs in the United States and Europe to develop gasification systems for production of SNG from coal. This effort led to pilot plant studies incorporating many of the major engineering approaches for development of superior gasification technologies. However, when petroleum and gas prices fell and it became clear that domestic resources were adequate to provide low-cost natural gas at least through the year 2000, the incentive for the construction of facilities for SNG production was eliminated, leaving a relatively few surviving commercial coal gasification systems. These were primarily aimed at manufacture of high-value products, such as methanol, ammonia, and chemicals. Today's emphasis on increased power generation efficiency, and the availability of high-performance gas turbines and fuel cells, have created a strong incentive for development of high-efficiency gasification systems specifically designed to provide fuel for power generation. These systems can differ from systems optimized to produce highly purified synthesis gas for catalytic conversion to chemicals and clean fuels in that dilution by methane and nitrogen is acceptable and a higher level of impurities can be tolerated.

State of the Art

The status of gasification processes of current interest that are either commercially available or have reached the stage of major pilot plant development is shown in Table 6-1.

Gasification processes can be divided into three major classes: entrained-flow, fluidized-bed, and moving fixed-bed. All involve operating pressures up to several hundred psi. For entrained-flow systems, powdered coal is generally first gasified with a mixture of steam and oxygen (or air) in a zone where the main part of the molten slag is collected. The high-temperature products require quenching or cooling prior to cleanup, with resulting loss of thermal efficiency. Entrained-flow gasification systems produce little methane, are relatively compact, and, because of the high operating temperature (1040 °C-1540 °C [1900 °F-2800 °F]), involve short reaction times. Entrained solid gasifiers are insensitive to most coal properties as long as the coal can be pulverized to about 80 percent below 200 mesh (44 micron) size. Entrained-flow systems, most notably the Texaco units, have found commercial application during the past decade for production of synthesis gas for chemical syntheses. The Texaco, Shell, and Destec processes are commercial technologies developed primarily in the United States. As a result of the required high reaction temperature and resulting high oxygen consumption, this class of gasifier has inherently lower thermal efficiency than fluidized-bed and moving fixed-bed gasifiers. The gas produced is relatively free of tars, hydrocarbons heavier than methane, and nitrogen compounds. Because of their proven performance, entrained-flow gasifiers have been chosen for IGCC demonstrations both in the United States and overseas. Such demonstrations primarily address systems integration issues rather than gasifier development.

Fluidized-bed gasification systems operate at 760 °C to 1040 °C (1400 °F to 1900 °F), depending on the reactivity of the feed coal and ash softening temperature, and have the potential

for higher efficiency. Because the temperatures on exiting the gasifier are well matched to the requirements for hot gas cleanup systems, fluidized-bed gasifiers offer overall efficiency advantages relative to higher-temperature entrained-flow systems that require gas cooling prior to cleanup. Relative to moving bed gasifiers, fluidized-bed units offer higher coal throughput rates, which reduce unit size and cost. Thus, fluidized-bed gasifiers offer an attractive method for producing a wide array of products from coal-derived gas. While no high-pressure systems are classified as commercial technologies, it should be noted that the atmospheric version (Winkler) has been in commercial use for over 65 years. Demonstration programs are under way in Europe and the United States. As discussed later in the section on technical issues and opportunities, the low-temperature Exxon Catalytic Process, with modifications, may offer the potential for high efficiency, although this program is currently inactive. The lower-temperature, higher-pressure versions of fluidized-bed gasification processes produce methane as well as synthesis gas, which requires less oxygen and increases the efficiency. Due to the low temperatures, the residues (ashes) from fluidized-bed gasifiers are possibly less inert and may require more attention to their disposal in an environmentally secure repository. A special ash agglomeration section, as in the Tampella/U-Gas and KRW gasifiers, can reduce this problem.

In the moving fixed-bed gasification process, approximately 2-inch \times 1/2-inch-sized coal moves down the reactor countercurrently to the gas flow. The countercurrent flow leads to higher efficiency. However, moving bed systems are more costly and more complex than stationary bed systems due to the equipment needed to maintain the flow of solids. Historically, the moving fixed-bed process is the most widely used gasification system. High temperatures above the oxidizing gas inlet decrease as the gases exchange heat and react with the incoming coal and exit temperatures are low. Some pyrolysis products (methane, light hydrocarbons, and tar) escape oxidation, and subsequent removal of the tar is required. The commercial Lurgi process yields an unfused ash clinker; however, a slagging version has been developed in cooperation with British Gas. A high-pressure version (6.9 MPa [1,000 psi]) with higher methane yields has been piloted. Use of in-bed limestone for sulfur capture is proposed, but hot gas desulfurization is also being considered. Because of the relatively long residence times and limitation on reactor diameter, moving fixed-bed units have lower coal throughput than is achieved with fluidized-bed units. Commercial moving bed gasifiers have capacities in the 800 to 1,000 tons/day range.

The Shell, Destec, and Texaco high-temperature entrained-flow gasifiers have a single-train capacity, resulting from the small coal particle size and high operating temperature, of up to 2,000 tons of coal/day, corresponding to about 265 MW of electricity. The high-temperature Winkler circulating fluidized-bed system planned for the European KoBra demonstration after the year 2000 has a planned capacity of about 300 MW using brown coal. To date, Lurgi fixed-bed units have a lower capacity than do entrained-flow units. This difference in capacity is subject to change with further development.

Gasification Technology and IGCC Performance

The first-generation U.S. IGCC systems are scheduled for demonstration in the ongoing CCT program (see Chapters 7 and 8) using the Destec and Texaco entrained-flow gasifiers with

design power generation efficiencies of 38 and 40 percent, respectively. Demonstration of the Shell gasifier as part of an IGCC system is under way in the Netherlands, and a Prenflo system demonstration is under way in Spain. Another IGCC demonstration project based on the moving bed British Gas/Lurgi slagging gasifier is included in DOE's CCT program but has not yet been contracted for. Also in the CCT program, a 100-MW IGCC system with a KRW fluidized-bed gasifier has been designed with an efficiency of 40.7 percent. Since all these systems make use of state-of-the-art 1300 °C (2350 °F) gas turbines, increases in efficiency to the 45 percent level projected for second-generation systems depend on the use of hot gas cleanup systems plus improvements in gasifier performance and optimized systems integration.

In addition to the method of contacting coal and oxidant (entrained-flow, fluidized-bed, or moving fixed-bed), important gasification choices include the use of air or oxygen, and hot or cold gas cleanup. Table 6-2 presents results of a study of the effects of these variables on efficiency using Illinois No. 6 coal in two gasifiers still in the development stage, namely, the KRW fluidized-bed system and the Asea Brown Boveri (ABB)/Combustion Engineering (CE) air-blown entrained-flow system, both using a General Electric MS7001 (1300 °C [2350 °F]) turbine (Gilbert/Commonwealth, Inc., 1994).² Both are scheduled for demonstration in the DOE CCT program.

The performance estimates in Table 6-2 show an overall thermal energy loss of approximately 15 to 20 percent in the gasification and gas cleanup steps. This results in a penalty of about five to 10 percentage points in electrical generating efficiency. Other findings from this study are as follows:

- When hot gas cleanup is used, changing from air to oxygen results in an efficiency reduction of approximately one percentage point (Cases 2 and 2a). This stems primarily from the energy requirements of oxygen production.
- For the air-blown systems, use of hot gas cleanup rather than cold gas cleanup results in an energy savings of 5 percent and a corresponding electrical efficiency gain of approximately two percentage points (Cases 1 and 1a, plus 3 and 3a). The efficiency advantage for hot gas cleanup is expected to be lower for oxygen-blown systems because of their lower mass flow rates and sensible heat loads.
- The most efficient system in this comparison is the air-blown fluidized-bed gasifier with hot gas cleanup plus in-bed sulfur removal (Case 1a). A gain of over three percentage points in net generating efficiency (HHV) is indicated compared to the oxygen-blown entrained-flow gasifier with cold gas cleanup (Case 3) of the type currently under demonstration. However, carbon dioxide emissions increase by 4.5 percent due to the calcination of limestone in the gasifier.

²The KRW air-blown in situ desulfurization version of the KRW process is scheduled for demonstration under CCT-IV at the Sierra Pacific Power Company. For this process, using western coal, the ash is sintered and removed as agglomerate. The ABB/CE process is scheduled for demonstration at City Water, Light and Power in Springfield, Illinois, with CCT cost sharing. The first stage of the entrained-flow system operates at 1480 °C to 1650 °C (2700 to 3000 °F) and produces a molten slag. The second-stage gas leaves at 1070 °C (1960 °F) and is then cooled to allow hot-gas cleanup (540 °C to 590 °C [1000 °F to 1100 °F]) with the General Electric zinc titanate/zinc ferrite sulfur removal and candle filtration.

The efficiency penalty for coal gasification can be attributed to losses involved in cooling the gasification product, the temperature cycling required by the gas cleanup system, the pressure drops incurred by all gas cleanup systems, and by flow through the gasification reactor. Continued R&D can likely reduce these losses, as discussed below.

Technical Issues and Opportunities

Improvements in the integration of coal gasification with advanced power generation systems are of greatest current interest. In the mid- to long-term periods (2006 through 2040), the production of hydrogen, clean low- and medium-Btu gaseous fuels for industrial and utility use, and synthesis of liquid fuels and chemicals are expected to be major potential applications for coal gasification. For both power generation and fuels production, greenhouse gas concerns are expected to greatly increase the emphasis on improved efficiency. Thus, new and improved gasification processes with higher thermal efficiency will be required.

The inherent problem of coal gasification is the high-temperature required to achieve a practical rate of reaction of coal with steam. The temperature varies—depending on the reactivity of the coal and the choice of gasifier—from about 800 °C to 1650 °C (1500 °F to 3000 °F) for uncatalyzed gasification. If the raw exit gases are cooled to the low temperature conventionally required for removal of hydrogen sulfide (H₂S) and other contaminants, losses in useful heat are incurred despite use of bottoming cycles and transfer of heat to other process streams.

These losses can be minimized by reducing cyclic heating and cooling of the gas. Several approaches are possible. Hot cleanup of the gasification product to minimize or eliminate cooling is currently limited to the temperature range of 650 °C to 760 °C (1200 °F to 1400 °F) and is primarily applicable to integrated gasification gas turbine or fuel cell systems for power generation. In these applications it has the potential for savings of one to three efficiency points relative to cold gas cleanup and is a major part of the DOE coal R&D program (see Chapter 7). Lowering the gasification temperature reduces these losses, but it also increases the direct formation of methane. The lowering of gasification temperature by increasing the reactivity of the coal (char) is achievable by use of catalysts; this has been studied extensively and piloted by Exxon. Acceptable reaction rates were obtained at temperatures down to 625 °C to 650 °C (1160 °F to 1200 °F). This approach remains a promising opportunity for cost reduction.

While methane is an undesirable product for hydrogen or syngas manufacture, its direct formation is advantageous for both SNG manufacture and power generation, since the volumetric heating value of the fuel gas is higher and cleanup and compression energy requirements are reduced. The direct formation of methane during gasification, or by prior pyrolysis, reduces oxygen and steam requirements and reduces the volume and heat capacity of the fuel gases. Use of oxygen instead of air further reduces the heat capacity and volume of the gaseous mixture. The use of oxygen, rather than air, for production of SNG, hydrogen, and synthesis gas-based liquid fuels and chemicals also eliminates dilution from atmospheric nitrogen; most gasification systems have been developed for oxygen use.

The manufacture of oxygen requires energy for air compression to drive the separation process and also represents a major capital expense. For gas turbine power generation, therefore, air-blown systems appear attractive. However, the larger volume of gas will increase both

temperature cycling and pressure drop losses. Oxygen-blown systems produce about half the gas volume of an air-blown system but consume energy for oxygen manufacture. The cold gas cleanup losses (approximately 1 percent) can also be reduced by tailoring cold gas cleanup to match the emissions requirements for power generation, which are considerably less demanding than for catalytic synthesis of SNG or liquids. For fuel cell systems, to avoid electrolyte degradation, a high level of cleanup might be economically desirable.

For use in clean fuel manufacture, air-blown systems that result in about 50 percent nitrogen dilution are impractical. Dilution by methane, while undesirable for stand-alone syngas plants, presents less of a problem in plants when electricity or steam generation can make good use of the waste gas from liquids and hydrogen manufacture. Oxygen-blown systems are, therefore, needed for these applications. As previously discussed (Table 6-2), the loss in power generation efficiency for oxygen-blown versus air-blown systems is about 1 percent for the KRW fluidized-bed system provided that hot gas cleanup is successful, and this small difference can likely be reduced by further research and optimization. With this small difference, the incentive for development of specialized air-blown systems is not clear.

No single gasification process is likely to be optimal for all applications; the wide range of coal properties will, in itself, affect the choice. An overriding need is for mechanical simplicity. Solid reaction systems are notoriously difficult to extrapolate, making development of any system to commercial scale a costly operation (about \$0.5 billion for each process). Thus, careful selection of R&D and demonstration programs to be pursued is extremely important. For maximum efficiency, the following general guidelines are offered: minimum gasification temperature to reduce temperature cycling and oxygen consumption and to maximize methane production. Production of fused ash to minimize solid waste removal/disposal problems also is an important goal. The use of catalysts to allow lower-temperature operations appears attractive to achieve significant improvements in efficiency and to minimize the production of tars. The cost of using catalysts would be a disadvantage.

Current Programs

DOE's participation in R&D and demonstration of gasification technologies falls into three categories: CCT programs,³ development programs, and advanced research programs related to gasification. The last two fall within the scope of the coal R&D program in DOE's Office of Fossil Energy.

The CCT programs summarized in Table 6-3 all involve gasification for power generation. The gasifiers, while constituting a fraction of the total program cost, are an essential feature of each demonstration. The gasification systems being demonstrated represent technologies of commercial interest to companies within the United States, including affiliates of overseas companies. Overall, the program should provide a basis for commercialization of IGCC power generation plants, as well as a framework for future advances in gasification efficiency and cost reductions for power generation.

Of the seven programs, five plan to use the currently experimental hot gas cleanup—one

³The general nature of CCT programs is discussed in Chapter 8.

on a 10 percent slipstream. Use of cold gas cleanup reduces efficiency by approximately two percentage points (see Table 6-2). Four of the programs will use air as the oxidant with an efficiency advantage of approximately 1 percent over the use of oxygen. These advantages are specific to dedicated power generation systems and would not be applicable to the supply of hydrogen or syngas for coproduction of liquid fuels.

Recent DOE budgets for surface coal gasification are shown in Table 6-4. The major expense is for construction of facilities for development of an Advanced Hybrid Gasification System. This facility is designed for development of an air-blown moving fixed-bed system with hot gas cleanup. The proprietary CRS Sitrine Engineers, Inc., PyGas™ staged gasifier has been selected for development with 20 percent industry cost share (CRS Sitrine Engineers, Inc., 1994). Given the committee's concern regarding optimization of gasification systems and the central role of the PyGas™ staged gasifier in the DOE program, the proposed technology is discussed below in some detail.

Coal, air, and steam are contacted in a cocurrent flow duct where the temperature rises to 815 °C to 980 °C (1500 °F to 1800 °F) and pyrolysis of the coal occurs. The hot pyrolyzed coal (char) falls to the top of a countercurrent fixed-bed gasification section, and dry ash is withdrawn at the bottom. Remaining tars are cracked in a tar cracking zone where the temperature is increased by addition of air. The pyrolyzed gases join the hot gas leaving the countercurrent section to produce a 112 Btu/dry standard cubic foot gas stream. The product gas temperature is expected to be around 815 °C (1500 °F). In Phase I of the project, limestone will be included to capture sulfur in the bed. The spent lime, which exceeds the amount of coal ash, must be treated to oxidize the calcium sulfide before disposal. Use of hot gas cleanup is proposed for a later phase of the program. This system appears to have potential for efficient integration with hot gas cleanup in a power generation system. However, because it is air-blown it would not be a good choice for coproduction of clean gaseous or liquid fuels.

In addition to the programs given in Table 6-4, there is a program for developing the Wilsonville facility centered around hot gas cleanup. In January 1992 the hot gas particulate removal test facility at Wilsonville, Alabama, was expanded to include system development and integration studies for advanced power systems and was renamed the Wilsonville Power Systems Development Facility. The facility could ultimately be reworked for gasifier research. The proposed FY 1995 budget for this facility is \$12.9 million.

The two gasification research programs suffered a 58 percent reduction in funding in FY 1994, with a further reduction proposed in the FY 1995 budget request. These small programs (\$0.8 million) are not sufficient to take advantage of the opportunities identified for further improvements in efficiency of gasification systems. Some additional discussion of advanced research opportunities for gasification can be found in Chapter 9.

PRODUCTS FROM COAL-DERIVED GAS

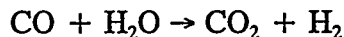
The raw gaseous products from coal gasification include hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), water (H₂O), ammonia (NH₃), hydrogen sulfide (H₂S), nitrogen (N₂), methane (CH₄), and, for the lower-temperature processes, higher hydrocarbons and tar. For conversion to "clean" gas suitable for combustion in simple equipment or for further

processing to other clean fuels or chemicals, the mixture is scrubbed to consist primarily of H₂, CO, CH₄, and N₂. This type of "synthesis gas" (syngas) mixture is currently of industrial importance for production of commodity chemicals and, to a growing extent, production of fuels. Natural gas is currently the dominant feedstock for production of syngas, with a large, continuing industrial and international R&D activity in this field. In this section the following major product categories are discussed: hydrogen, synthetic natural gas, methanol and other oxygenated products from synthesis gas, and products from F-T (Fischer-Tropsch) synthesis. The costs presented are based on the standard utility financing used by DOE. Costs would be \$6 to \$10/bbl higher for liquid feed production from coal if conventional petroleum industry financing were assumed (see Glossary).

Hydrogen Production

Major uses for hydrogen include ammonia manufacture for fertilizers and the refining of petroleum liquids with low hydrogen and high sulfur content. Hydrogen is also required to convert fossil resources into transportation fuels, since the hydrogen-to-carbon ratio for liquid transportation fuels is approximately two, compared to less than one for coal and slightly greater than one for petroleum tars.

The standard technique for hydrogen manufacture from natural gas or by coal gasification is to employ the water/gas shift reaction:

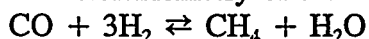


Production of hydrogen is favored by low temperatures, but satisfactory reaction rates currently require a temperature of 300 °C to 700 °C (570 °F to 1290 °F). In addition, a high level of acid gas (H₂S, CO₂, hydrogen chloride [HCl]) removal is needed to maintain catalyst reactivity. Hydrogen can also be separated from synthesis gas by cryogenic distillation. Another alternative for hydrogen production is to develop processes for the production of SNG, methanol, or liquid fuels that accomplish the shift of H₂/CO mixtures in situ, thereby avoiding energy losses incurred by heating and cooling, the shift reaction, and subsequent removal of CO and CO₂ from the product stream. Pressure swing methods for hydrogen separation are advantageous principally for small- and medium-scale applications.

If pure hydrogen could be obtained economically as a coproduct from the coal-derived fuel gas supplied for electric power generation, it might be used for high-efficiency fuel cell operation, hydrogenation of by-product coal pyrolysis liquid, direct coal liquefaction, or sold for the many conventional applications of hydrogen. New materials to allow efficient, low-cost separation of hydrogen from coal-derived gas by selective membrane diffusion offer performance enhancements (NRC, 1993), as discussed further in Chapter 9.

Synthetic Natural Gas Production

SNG is produced from gasified coal by a set of reactions of CO, CO₂, H₂, and H₂O over a catalyst to form methane. While the stoichiometry of the reaction is



in the presence of catalysts, the interchange between the feed components can be rapid and controlled by thermodynamic equilibrium, such that the feed H_2/CO ratio can be much lower than the stoichiometric 3/1 ratio. While the above methane synthesis reaction is highly exothermic, the gasification reactions to form synthesis gas are about equally endothermic, and the balancing of these reactions to minimize thermal losses from heating and cooling is essential for achievement of high efficiency. A large number of catalysts and systems have been studied with the goal of minimizing cost. An extensive discussion of SNG technology can be found in a report from the DOE Coal Gasification Research Needs Working Group (COGARN, 1987).

The one commercial SNG facility in the United States, the Great Plains plant in North Dakota, was built in the late 1970s by a consortium of natural gas companies in anticipation of constraints on natural gas supply and associated price rises. Despite the low cost of coal today and technically satisfactory operation, the plant is only profitable because contractual product prices are higher than the market price and a large portion of the capital costs is borne by the federal government. SNG is also produced in South Africa, and China plans to build a \$220 million plant in Henan province to produce 40 Mcf/day of SNG, with over 20 percent of the coal gas destined for use as petrochemical feedstock (Oil and Gas Journal, 1994).

The Great Plains plant uses 14 Lurgi dry bottom gasifiers followed by cold gas cleanup to reduce sulfur content to less than 1.0 ppm. The H_2/CO ratio produced is around 2.0, while for the higher-temperature British Gas Lurgi slagging gasifier the ratio is 0.46, with ratios for other gasification systems falling between these limits. Advanced catalytic systems for directly converting the low H_2/CO ratio gas from coal gasification have been an active R&D area. Goals include improvement in sulfur tolerance by appropriate choice of catalyst and operating conditions, better reactor temperature control, and avoidance of carbon formation favored by low-hydrogen-content fuel gas.⁴ It has been estimated that when commercialized these advanced technologies, together with limited work on improvements in the removal of acid gases, will reduce SNG costs by 25 percent for stand-alone plants using western coal (COGARN, 1987).

For the year 2010, EIA (Energy Information Administration) projects a wellhead price for natural gas of \$3.50/Mcf (EIA, 1994), and continued increases in price may be expected past this date as a result of resource limitations. Substitution of coal-generated low- and medium-Btu gas for natural gas for power generation and industrial use could make additional supplies of natural gas available for domestic and commercial consumers. Thus, the need for major dedicated SNG manufacture could well be delayed beyond the year 2021.

Currently there are no DOE programs budgeted specifically for SNG production. However, since the major cost and energy consumption are incurred by the gasification step, opportunities for improvement are similar to those for oxygen-blown advanced IGCC and fuel cell systems. A program aimed at improving gasification thermal efficiency could be applied to both uses, providing an additional incentive for an integrated gasification program.

⁴Methane is also produced noncatalytically in low-temperature gasification by thermal equilibration. The Exxon fluidized-bed catalytic gasification process makes use of this reaction with cryogenic separation of the methane produced (15 to 20 volume percent of gas at 650°C [1200°F]) and recycle of unconverted feed. Methane can also be produced from coal pyrolysis, and lower-temperature processes can provide up to 20 percent methane by volume in the gasifier product. High-temperature entrained-flow processes produce little methane.

Liquid Products from Synthesis Gas

By careful choice of catalyst and conditions, synthesis gas can be reacted to produce higher hydrocarbons and oxygenates such as methanol. These products are useful for commodity chemicals, are of increasing interest for use as transportation fuels, and have been considered for production of storable supplementary fuel for IGCC electric power plants (EPRI, 1984; Tam et al., 1993).

The reaction between carbon monoxide and hydrogen to produce paraffinic oxygenates or hydrocarbons is extremely exothermic (Probstein and Hicks, 1982). The heat evolved is approximately 20 percent of the heat of combustion of the product and, because of the narrow temperature range over which the catalysts provide satisfactory selectivity to the desired product, control of reaction temperature is a major engineering challenge. The difference between the several catalytic processes in use or under development is largely related to differences in approach to temperature control and choice of catalyst.

Methanol

Methanol has been a major commodity for many years, with principal uses in the chemical industry and as a solvent. It can also be used as a motor fuel and, with the requirement for inclusion of oxygenates in gasoline, its use for preparing oxygenated components by reaction with olefins has grown rapidly. Its direct use as a gasoline blending agent is limited by its relatively low solubility in gasoline and its tendency to be extracted by any water present in the gasoline distribution system. Its use as the primary fuel component offers good performance but is limited by cost in competition with imported petroleum, a potential problem with formaldehyde emissions, and the difficulties of establishing an adequate distribution system and availability of automotive systems designed to use this fuel. Other limitations of methanol are its high toxicity, potential reaction with elastomers used in the automobile fuel system, the fact that it burns with an invisible flame, the potential for ground water pollution, and a limited driving range because of the low energy content per unit volume.

Methanol is made by the catalytic conversion of syngas at about 250 °C (480 °F) and a pressure of 60 to 100 atmospheres. Both coal and natural gas can be used as syngas sources. The current commercial processes use a fixed-bed catalytic reactor in a gas recycle loop. There are a wide range of mechanical designs used to control the heat released from the reaction. Lurgi and Imperial Chemical Industries technologies currently dominate, but other designs are offered by Mitsubishi, Linde, and Toyo corporations. New developments in methanol technology include use of a liquid-phase slurry reactor for methanol synthesis and fluidized-bed methanol synthesis being developed by Mitsubishi Gas Chemical. Liquid-phase slurry reactors offer improved control of temperature and are of considerable interest for both methanol and F-T hydrocarbon production. A DOE-owned liquid-phase slurry reactor plant at LaPorte, Texas, has been operated with industry cost sharing for a number of years. A DOE-supported demonstration plant is now being built by Eastman Chemical at Kingsport, Tennessee. In the fluidized-bed design a fine catalyst is fluidized by syngas. Better contact between syngas and catalyst gives a higher

methanol concentration exiting the reactor, which reduces the quantity of recycle gas, the recycle compressor size, and the heat exchange area in the synthesis loop.

A study on production technologies for liquid transportation fuels (NRC, 1990) provides some perspective on costs of methanol production using both coal and natural gas as syngas sources. Natural gas at current prices is by far the lowest-cost feed, but at a delivered natural gas price of greater than \$4 to \$5/Mcf, coal gasification was judged to be competitive.

Methanol-Derived Fuels

There has been extensive industrial R&D, in the United States and overseas, on processes to convert methanol to gasoline, olefins, and diesel fuel (NRC, 1990). Major participants include Mobil Research and Development Corporation, Union Rheinische Braunkohlen Kraftstoff AG, Uhde GmbH, Haldor Topsoe, Mitsubishi, and Lurgi. Technologies for the conversion of methanol to gasoline have been demonstrated at scales of 1 to 100 bbl/day, and the Mobil process operates commercially in New Zealand producing 14,500 bbl/day of gasoline from syngas derived from natural gas rather than coal. Conversion of methanol to olefins has been demonstrated in Germany at a 100 bbl/day scale; high-quality gasoline is also produced. At present, however, new plants for hydrocarbon fuel production from natural gas use the F-T synthesis, indicating no current major advantages for prior synthesis of methanol.

Production costs for imported methanol manufactured from overseas natural gas at \$1.00/Mcf have been estimated (NRC, 1990) at \$29/bbl equivalent crude oil cost (for gasoline equivalent). This cost is approximately competitive with methanol production from coal using advanced technology and coproduction with electric power (Tam, 1993). Even when domestic natural gas prices rise to a level where dedicated production from coal could compete economically, natural gas is expected to remain the lowest-cost syngas source for methanol production due to the large overseas supply of very low cost natural gas. However, as discussed later in the section on coal refineries and coproduct systems, coproduction with gasification combined-cycle power generation might be competitive with imported methanol.

While there is extensive industry activity on methanol synthesis starting with natural gas and using synthesis gas with the stoichiometric H_2/CO ratio of 2.0 and low or very low sulfur content, there is relatively little activity on development of once-through processes using low H_2/CO ratios and sulfur concentrations achievable with hot gas desulfurization. Such a process could be more efficient and advantageously integrated with coproduction of electricity.

F-T Synthesis

The F-T process reacts and polymerizes synthesis gas to produce a wide range of products: light hydrocarbon gases, paraffinic waxes, and oxygenates. Further processing of these products is necessary to upgrade the waxy diesel fraction, the low-octane-number gasoline fraction, and the large amount of oxygenates in the product water. A premium diesel fuel can be manufactured from the higher-molecular-weight hydrocarbons and the wax. The gasoline boiling range fraction has low octane number and requires more substantial upgrading to produce

useful motor fuel. The distillation of high-molecular-weight products can be adjusted by choice of catalyst and operating conditions; wax produced as an intermediate is hydrocracked to produce a high cetane product. Greatest current interest is in the production of high-molecular-weight material for diesel and jet fuels, for which the low sulfur and high hydrogen content (compared to petroleum fractions) commands a premium price.

As with methanol, there is active industrial interest in the use of low-cost overseas natural gas to manufacture F-T synthesis products. The largest commercial activity with coal feed is by the South African Coal, Oil, and Gas Corporation (Sasol) in South Africa (NRC, 1990). Most of the R&D in the United States on F-T processes has been conducted by Exxon. Important research areas are in catalyst development and optimization of processing conditions. Highlights of F-T development and commercialization activities are summarized in Table 6-5. For production of both methanol and hydrocarbons, the slurry process has been a focus of DOE research since it can accept the low-hydrogen/carbon monoxide synthesis gas produced from coal without the additional step of shifting the ratio required by the traditional fixed-bed systems. Success of this DOE approach has been demonstrated in a large-scale pilot plant at LaPorte, Texas, with joint DOE/industry funding.

While there is an active international R&D program on F-T for use in remote natural gas locations, improved catalysts and process conditions for once-through processes with electricity as a coproduct may offer research opportunities specific to coal.

The results of DOE-sponsored design and systems studies on the cost of coal liquids production for stand-alone indirect liquefaction plants and for coproduction of coal liquids with gasification-based power generation are discussed below (see Coal Refineries and Coproduct Systems).

PRODUCTS FROM DIRECT LIQUEFACTION AND PYROLYSIS OF COAL

Direct Liquefaction

Background

In direct liquefaction, hydrogen is added to coal in a solvent slurry at elevated temperatures and pressures.⁵ The process was invented by Friedrich Bergius in 1913 and was commercialized in Germany and England in time to provide liquid fuels during World War II. The first U.S. testing of direct liquefaction processes followed World War II (Kastens et al., 1949); efforts in the area declined when inexpensive petroleum from the Middle East became available in the early 1950s. Interest revived when the Arab oil embargo of 1973 caused high oil prices, resulting in increased federal funding for such research. A variety of process concepts were examined on a small scale (10 to 20 tons/day), and three—Solvent Refined Coal, Exxon Donor Solvent, and H-Coal—were tested on a large scale (200 to 300 tons/day) in the late 1970s and early 1980s (NRC, 1990). The DOE provided much of the funding for these successful

⁵Direct liquefaction is generally believed to be 5 to 10 percent higher in efficiency than indirect liquefaction because of lower consumption of gasified coal (Stiegel, 1994).

demonstrations, but none of the processes proved economical when oil prices fell in the early 1980s. Overseas, Veba Oil and others built and operated a large-scale pilot plant at Bottrop, Germany, in the late 1970s and early 1980s. The facility is currently being used to hydrogenate chlorinated wastes. This facility was funded primarily by the German government. Demonstration of the liquid solvent extraction process developed by the British Coal Corporation is continuing at the Point of Ayr Plant in Wales with both industrial and government support. In the late 1980s the Japanese operated a 50-ton/day liquefaction plant in Australia (NRC, 1990).

State of the Art

Products of direct coal liquefaction can be refined to meet all current specifications for transportation fuels derived from petroleum. Major products are likely to be gasoline, propane, butane, and diesel fuel. Production of high-quality distillate fuels requires additional hydrogen to decrease smoking tendency and to increase cetane number for use in diesels.

High octane is achieved by the high aromatic content of the liquids. At one time, this was considered to be an advantage; however, the CAAs (Clean Air Act amendments) of 1990 place sharp limits on the aromatic content of motor fuels in the United States. Fortunately, the benzene content of gasoline made from coal is extremely low; the concentration of other aromatics can be reduced by hydrogenation to produce naphthenes at a modest increase in cost. This increases the volume of the products, decreases the octane number, and increases process hydrogen consumption.

The projected cost for direct coal liquefaction has dropped by over 50 percent since the early 1980s (Lumpkin, 1988). Recent improvements in economics cannot be attributed to any single breakthrough but rather to the accumulation of improvements over several years of operation, notably the following:

- A more effective and reliable process was developed to remove solids from the liquid product by controlled precipitation, replacing a filtration process.
- A second catalytic reactor was added to improve control over the chemistry of liquefaction. This reactor was first installed downstream of the solids removal and distillation systems; moving the reactor upstream further improved operation.
- Some of the recycled liquid used to slurry the feed coal was bypassed around the solids removal unit, increasing the efficiency of the unit.
- Improved catalysts were added to both the first and second reactors.

This series of modifications led to higher liquid yields, improved conversion of nondistillable liquids, less rejection of energy along with discarded coal minerals, and increased throughput relative to early two-stage systems. The success of this evolution shows that steady R&D can achieve major technological advances over time. The current U.S. direct liquefaction technology appears to be the best for U.S. coals, but work continues overseas with emphasis on other coals. All of the foreign projects have had the bulk of their financing contributed by government.

Current Programs

U.S. research into direct coal liquefaction continued after the big pilot plants were abandoned in the 1980s, but both industrial and DOE activities have steadily decreased with time. Small test units capable of continuous operation for sustained periods of time were available at Hydrocarbon Research, Inc., Exxon, Lummus-Crest, the University of Kentucky, and Amoco Corporation, but today are either shut down or only in limited use. The Advanced Coal Liquefaction R&D Facility in Wilsonville, Alabama, operated full-time through 1991. Hydrocarbon Research, Inc., started up a smaller facility in the second half of 1992 under DOE sponsorship. The unit operates approximately half-time, but funding beyond 1994 is uncertain. Research at West Virginia University on the production of coal-derived precursors using solvent extraction techniques as carbon product feedstocks has been supported by DOE. However, DOE funding for advanced research in direct liquefaction has decreased in recent years (see Chapter 9).

Technical Issues, Risks, and Opportunities

A 1989 assessment of research needs conducted by DOE's Office of Program Analysis outlined a comprehensive program aimed at bringing down the cost of direct liquefaction (Schindler, 1989). Industry participants in the aforementioned study stressed the need for federal funding of a large-scale pilot plant capable of processing 150 tons or more of coal per day, but such a unit was never funded. In addition, funding of intermediate-size flow units of the size of the Hydrocarbon Research, Inc., facility was recommended to test changes in process configuration at reasonable cost. Smaller pilot plants are needed to evaluate catalysts, explore operating conditions, and provide low-cost testing of new ideas.

A design and system analysis study, based on runs at the DOE Wilsonville plant, was carried out by a Bechtel-Amoco team under contract to PETC (DOE, 1993b).⁶ Using Illinois No. 6 coal (bituminous), the equivalent crude price was approximately \$33/bbl, compared to estimates of \$44/bbl prepared for an earlier study (NRC, 1990). This cost reduction results from the incorporation of more recent results from the DOE Wilsonville plant, improved gasification, and from inclusion of 3 percent inflation in the DOE-sponsored estimates. The earlier estimates assumed 10 percent return and did not include inflation. If inflation were eliminated from the current DOE-sponsored calculations, the equivalent crude cost would be increased by approximately \$5/bbl. An extension of the Bechtel-Amoco study will be based on lower-cost Wyoming coal and is expected to reduce the equivalent crude costs to slightly less than \$30/bbl. On the basis of achievements to date, there is now optimism at DOE and among some industry groups that the \$25/bbl target (in 1991 dollars) set by DOE (DOE, 1993a) may be attainable by sustained R&D and continued optimization studies.

The 1989 assessment (Schindler, 1989) also recommended a broad range of fundamental and exploratory research, based on the recognition that possible improvements to the current

⁶This study assumed *n*th plant costs with 3 percent per year price inflation over the plant life, 25 percent owner equity with 15 percent return, and 8 percent interest charges for the 75 percent loan.

technology may be limited but that advances in conversion chemistry may bring down the cost of liquid fuels produced from coal to be competitive with petroleum products. Possible approaches to conversion chemistry that might achieve costs below the current \$25/bbl goal include low-pressure reaction (2.17 MPa [300 psig] or less), direct use of gasifier product, use of low-cost subbituminous coal or lignite, removal of oxygen in coal as carbon dioxide, and elimination of product hydrocarbon gases (increased selectivity).

Integration of direct coal liquefaction with an existing petroleum refinery could take advantage of existing facilities and ease the transition between petroleum and coal feedstock. DOE sponsored work on simultaneous processing ("coprocessing") of coal with heavy petroleum fractions in an ebullated-bed hydroprocessing reactor. One CCT program submission utilizing this technique was selected for funding but was unable to find the private sector funding needed to proceed.

Coal Pyrolysis

Pyrolysis of coal dates back to the eighteenth century, using temperatures below 700 °C (1290 °F) in fixed- or moving fixed-bed reactors. The primary product was a low-volatile smokeless domestic solid fuel, although the value of the liquid products was also soon recognized. During the 1920s and 1930s there was a great deal of R&D in low-temperature processes, but interest dwindled in the mid-1940s when gas and oil became readily available at low prices. With the oil embargo and increased oil prices of the early 1970s, interest renewed in coal pyrolysis, but in more recent times interest has again declined along with petroleum prices (Khan and Kurata, 1985).

Pyrolysis kinetics are reasonably well understood and have been modeled extensively (Solomon et al., 1993). Both yield and liquid fuel properties depend on pyrolysis conditions. Pyrolysis under mild temperatures (500 °C to 700 °C [930 °F to 1290 °F]) and pressures (up to 50 psig) with rapid heat-up can produce high liquid yields without adding hydrogen. However, a significant part of the feed coal remains as char with market value comparable to or somewhat less than that of the feed coal. Coal pyrolysis offers some promise of lower liquid costs if the char can be upgraded to higher-value specialty products, such as form coke, smokeless fuel, activated carbon, or electrode carbon, or if the liquid yield can be significantly increased by using low-cost reactants (steam and carbon dioxide) or catalysts. Pyrolysis liquids have a low hydrogen-to-carbon ratio, generally less than one, in contrast to petroleum tars and bitumens (around 1.4) and high-quality petroleum products (approximately 2.0). They also contain substantial amounts of oxygen, compared to tars, and thus require more extensive hydrogen addition to produce specification fuels. Their tendency to polymerize on standing can cause operational problems, which also must be addressed.

Little heat is required to produce pyrolysis liquids from coal, however, and production as a side stream to coal gasification or fluidized-bed combustion is efficient. Pyrolysis reactors generally operate at modest pressures and temperatures compared to other coal conversion systems and offer high throughput. Both of these features lead to low capital cost. The cost of pyrolysis liquids could thus be low and might be competitive with bitumen or for integration with oil refinery hydroconversion operations where their solubility characteristics could improve

the operability of hydrocarbon units. They could also be combined with direct coal liquefaction. When made from low-sulfur coal, pyrolysis liquids have limited potential as a substitute without refining for petroleum fuel oil, and an ongoing CCT program (ENCOAL Mild Coal Gasification project) is aimed at this market. Pyrolysis liquids have traditionally been a source of coal tar chemicals, and the DOE Mild Gasification program is aimed, in part, at this market (see below).

The budget for the DOE Advanced Clean Fuels Program within the FE coal R&D activity underwent a 30 percent reduction between FY 1993 and FY 1994, and a further 45 percent reduction is proposed for FY 1995 (see Table 2-1). These budget decisions reflect a diminished commitment to the use of coal for production of clean liquid fuels by either indirect or direct liquefaction. Of particular note is the proposed reduction of 84 percent in FY 1995 funding for Advanced Research and Environmental Technology; programs in this area are expected to lead to improvements in efficiency and cost reductions for liquid fuel production (see Chapter 9).

COAL REFINERIES AND COPRODUCT SYSTEMS

A coal refinery or coproduct system is defined as "a system consisting of one or more individual processes integrated in such a way as to allow coal to be processed into two or more products supplying at least two different markets" (DOE, 1991). The concept resulted from the realization that coal must be processed in nontraditional ways to meet the needs of potential expanded markets. A key feature of the coal refinery concept is the production of more than one product form, for example, steam and electricity or fuel gas and electricity. The concept can be generalized to include cogeneration of steam and electricity, production of fuel gas for both industrial heat and electricity generation, production of syngas for manufacture of chemicals and/or fuels, capture and use of pyrolysis tars for chemicals and fuels manufacture, and production of specialty cokes.

Cogeneration

Cogeneration was initially practiced in energy-intensive industrial plants to meet internal needs for steam and electricity. Steam and electricity coproduct systems are now a major commercial activity. With few exceptions cogeneration facilities are designed to use natural gas because of the lower investment compared to a plant that uses coal. As natural gas prices rise to a level that renders the higher investment in coal facilities economically advantageous, advanced cogeneration systems, where the first step is gasification, could also supply coal liquids, fuel gas, and syngas made from coal. Currently, there appears to be ample opportunity for a variety of coproducts produced by the primary coal gasification process. Steam and electricity would continue to be major products.

It seems reasonable to expect that the time for introduction of cogeneration systems based on coal would approximately correspond to the time when the projected cost and/or availability of natural gas would justify investment in new coal-based, power-generating facilities, perhaps during the mid-term period (2006-2020). This time might well arrive before manufacture of

synthetic natural gas is required to meet domestic demand. The large world resources of petroleum and bitumen, combined with low prices, are expected to defer manufacture of liquid transportation fuels from coal until the price range is \$25 to \$30/bbl, although security considerations could call for an earlier date. The first major opportunity for coproducts would then arise from the predicted mid-term need for new high-performance coal-based, power generation systems. These high-performance systems will probably involve coal gasification offering the possibility of coproducts from the gasifier (syngas, fuel gas, and pyrolysis tar). The production of coproducts, in conjunction with SNG manufacture, was of major commercial and DOE⁷ interest until the 1980s, when low oil and gas prices and ample supplies eliminated the near-term economic incentive for synthetic fuels processes. The expected growth in coal-based power generation appears to offer a more robust opportunity for fuel and chemical coproducts than the traditional single product or dedicated plant approach.

The business environment and regulatory changes that have encouraged cogeneration could provide a framework for extension to the use of coal as a source of energy and a resulting greater variety of coproduct streams. Recent industrial concerns regarding efficient production of major products and conservation of capital are resulting in steam and power being supplied by external companies that build and operate facilities for supply of steam and electricity to both local manufacturing plants and utilities. In some cases these companies are subsidiaries of a utility. Such companies might supply fuel gas and syngas to chemical and petrochemical companies. Nonetheless, the complexity of the potential business relationships and the need for a flexible approach should not be underestimated.

With today's emphasis on increased generation efficiency and the availability of high-performance gas turbines and fuel cells, an incentive for development of high-efficiency gasification systems specifically designed to provide fuel for power generation has been established. As discussed earlier, these systems can differ from systems optimized to produce highly purified synthesis gas for conversion to chemicals and clean fuels in that dilution by methane and nitrogen is acceptable; a higher level of impurities can also be tolerated.

Indirect Liquefaction

DOE-sponsored design and systems studies by the Mitre Corporation and Bechtel (Gray, 1994; Tam et al., 1993) have provided information on cost for both present-day stand-alone indirect liquefaction plants and coproduction of coal liquids with gasification-based electrical power generation.⁸ For the stand-alone F-T synthesis, the Mitre study found an equivalent crude price of \$35/bbl. Coproduction with electricity reduced the equivalent crude cost by \$5 to \$6/bbl to approximately \$30/bbl. The savings for coproduction were attributed to a combination of better heat integration and the economies involved in once-through operation.

⁷Prior to the formation of DOE in 1977 programs were conducted under the auspices of the Energy Research and Development Administration.

⁸See Chapter 2 and the Glossary for discussion of financing options.

The study by Bechtel estimated a difference in equivalent crude cost of coal liquids produced by stand-alone and coproduction methods of approximately \$7/bbl. For coproduction, the gasoline boiling range fraction was sent to the turbines, thus reducing total liquid production but also avoiding the costs of upgrading the low-octane-number naphtha produced by this process. While the required selling price was similar to that for the Mitre study, the assumed refined product values were higher, with a larger assumed premium for the diesel fuel. This assumption, together with other cost differences, makes comparison of the two studies difficult. The Bechtel study estimates an equivalent crude price for coproduction of somewhat less than \$25/bbl. The cost estimates from the Bechtel and Mitre studies differ significantly from those found in a previous National Research Council study (NRC, 1990), where the estimated equivalent crude price was greater than \$40/bbl for the stand-alone plant. The difference results from a combination of the inclusion of inflation in the DOE-sponsored studies, higher product values, improved gasification technology, and use of the slurry reactor.

World oil prices in 2010 are projected to be in the range of \$18 to \$34/bbl (EIA, 1994). For the EIA reference case, the projected oil price in 2010 is \$28/bbl, indicating that, on the basis of the estimated costs discussed above, indirect liquefaction could be of commercial interest within the mid-term timeframe (2005–2020). However, it is important to note that the estimated costs from the Mitre and Bechtel studies are for the "nth" plant and are below pioneer plant costs. As in the case of advanced power generation technologies, early market entry would likely require some federal cost sharing (see Chapter 8).

Direct Liquefaction

Coproduction of coal liquids and electric power based on IGCC systems offers additional opportunities for cost reduction in the production of hydrogen, which could be used for direct liquefaction. No estimates of the magnitude of possible benefits are available for direct liquefaction; however, they would probably be somewhat less than those predicted for the F-T process because of lower synthesis gas consumption.

Current Programs

The U.S. Congress, in EPACT, directed DOE to examine the potential of coal refineries, evaluate their potential for meeting new markets, outline R&D needs for potential commercialization, and prepare a report on the subject for congressional consideration (see Appendix A). DOE activities related to this directive have included continuation of the program sponsored by DOE's Morgantown Energy Technology Center aimed at commercialization of the mild gasification process, which is based on pyrolysis and is directed toward producing specialty cokes and tars for production of chemicals. No further funding for the program has been requested for FY 1995. In addition, the ENCOAL mild coal gasification project is being funded by DOE on a 50/50 cost-share basis with ENCOAL Corporation under Round III of the CCT program. The two year operational test period began in July 1992, and solid process-derived fuel

and coal-derived liquids have been produced. DOE has also issued the mandated report to Congress (DOE, 1991).

DOE coal R&D funding for systems for coproducts is divided into two categories: the mild gasification program and conceptual studies of coproduction of electricity and coal liquids. The former activity at the Illinois Mild Gasification Facility is cost shared with Kerr/McGee. It received \$1.5 million in FY 1993 and \$3.9 million in FY 1994; no funding was requested for FY 1995. A similar process is addressed in the ENCOAL CCT project, thereby reducing the incentive for major continuation of funding under the coal R&D program. A conceptual study of electricity and coal liquids production—as proposed in the FY 1995 congressional budget request—could extend the existing preliminary studies. In FY 1995, \$0.6 million was requested for this study; there was no funding for this activity in FY 1993 and FY 1994.

FINDINGS

Coal Gasification Technology

1. Technology for the manufacture of clean gas is unique to coal-based systems; technology development is not addressed in DOE Fossil Energy programs other than those relating to coal (FE coal R&D and CCT).

2. The expected major future use of coal gasification in power generation has stimulated industrial R&D for gasification systems tailored to high-efficiency power generation requirements. Seven systems are scheduled for demonstration in the CCT program. However, further improvements in gasifier performance are required to achieve DOE's 45 percent efficiency goal for second-generation IGCC systems.

3. Use of coal gasification for supply of clean gaseous and liquid fuels, in addition to uses for power generation, provides an incentive to develop improved processes for this set of interacting needs. Fluidized-bed systems, with possible use of catalysts, offer an attractive method for providing the entire array of products from coal because of their temperature characteristics and compatibility with hot gas cleanup systems.

4. There are systems integration and research opportunities for further improvement in combined gasification/gas cleanup efficiency.

5. The air-blown fixed-bed gasifier scheduled for development at the DOE Gasification Product Improvement Facility may be competitive for use in a hot gas cleanup combined-cycle power generation system. If cold gas cleanup is used, the overall advantage over current commercial systems is not clear.

6. Despite opportunities for technology improvement, the proposed FY 1995 budget indicates reductions in funding for gasifier development, systems studies, and research.

Gaseous Products

1. Manufacture of low- and medium-Btu gas is expected to play a major role in high-efficiency power generation systems, as a source of syngas and hydrogen for manufacture of coal-based liquid fuels, and for production of industrial chemicals.

2. Improvements in gasification efficiency and reductions in capital cost offer major R&D opportunities.

3. While domestic natural gas is currently favored as fuel and as a source of hydrogen and synthesis gas, projected increases in price and decreased availability will increasingly favor use of coal-based gases. Displacement of natural gas by coal-based low- and medium-Btu gas can extend the supply of low-cost natural gas for domestic and commercial consumers and postpone the need for synthetic natural gas facilities.

4. Minimum CO₂ production, as well as cost, will be important factors in the choice of processes to manufacture gaseous products from coal.

5. Efficient separation of gaseous products and gas cleanup processes offer opportunities for improvement.

Liquid Fuels from Coal

1. Advances in coal gasification and liquefaction technology have reduced estimated costs to approximately \$33/bbl equivalent crude oil cost for mature (i.e., not pioneer) single-product plants using direct liquefaction with Illinois No. 6 coal.

2. Experience with sustained R&D indicates that DOE's goal of \$25/bbl (1991 dollars) for coal-based liquids may be attainable with continued research and systems studies.

3. Industrial programs have been drastically reduced.

4. The DOE budget for FY 1995 proposes a drastic reduction in liquefaction activities.

Coal Refineries and Coproduct Systems

1. The concept of coal refineries or coproduct systems, defined as the production of more than one commercial product from coal, offers opportunities for optimization and significant cost reduction of coal conversion systems relative to single-product plants.

2. Coproduction with electricity has the potential to reduce indirect coal liquefaction costs by \$6/bbl or more, indicating that pioneer production of liquids may become economically attractive in the timeframe projected for widespread construction of advanced gasification power generation facilities.

3. Opportunities for coproducts could determine the choice of gasification technology. Systems studies are needed to identify the major research, development, and commercialization opportunities.

4. The first major opportunities for implementation of coal refineries will likely involve electric power as the major product. Indirect liquefaction could well be the first application of coproduction with electricity.

5. The large reduction in FY 1995 funding for DOE coal R&D programs relating to coproduct systems is caused by discontinuation of the mild gasification activity. DOE has proposed \$0.6 million for conceptual studies of coproduction of liquids and electricity.

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Table 6-1 Status of Gasification Processes

Developer ^a	Status	Gasifier Exit Temperature °C (°F)
<u>Entrained-Flow Processes</u>		
Texaco (U.S.), CCT	Commercial	1260–1480 (2300–2700)
Shell (Europe/U.S.)	Commercial	1370–1540 (2500–2800)
Destec (U.S.), CCT	Commercial	1040 (1900)
Prenflo (Europe)	Commercial/ demonstration	1370–1540 (2500–2800)
Koppers Totzek (Europe) -Atmospheric	Commercial	1480 (2700)
ABB/Combustion Engineering (Europe/U.S.), CCT	Development	1040 (1900)
IGC (Japan)	Development	1260 (2300)
HYCOL (Japan)	Development	1480–1620 (2700–2950)
VEW (Germany)	Development	
<u>Fluidized-Bed Processes</u>		
KRW (Europe/U.S.), CCT	Demonstration/ development	1010–1040 (1850–1900)
High-Temperature Winkler/Lurgi (Europe)	Demonstration/ development	950 (1750)
Exxon Catalytic (U.S.)	Development (currently inactive)	760 (1400)
Tampella/UGas (Finland/U.S.), CCT	Development	980–1040 (1800–1900)
MCTI Pulse Combustor/Gasifier, CCT	Demonstration/ development	1090–1260 (2000–2300)
<u>Moving Fixed Bed Processes</u>		
Lurgi (dry ash) (Europe)	Commercial ^b	
British Gas Lurgi (slagging), CCT	Demonstration	
British Gas Lurgi (high pressure, 1,000 psi)	Development	
DOE-Sirrine Advanced Moving Bed (U.S.)	Research/ development	850 (1560)

^aCCT is technology demonstrated in DOE's Clean Coal Technology program (see Table 6-4).

^bOver 100 units in operation.

Sources: COGARN (1987); DOE (1994b).

Table 6-2 Effect of Gasifier Design on IGCC Efficiency

Case Number	1	1a	2	2a	3	3a
Gasifier ^a	KRW fluidized-bed	KRW fluidized-bed	KRW fluidized-bed	KRW fluidized-bed	CE entrained-flow	CE entrained-flow
Oxidant	air-blown	air-blown	air-blown	oxygen-blown	air-blown	air-blown
Gas cleanup ^b	in situ plus cold gas	in situ plus hot gas	hot gas	hot gas	cold gas	hot gas
Carbon-to-gas efficiency ^c	81.3	86.4	85.9	84.6	79.0	84.5
Coal-to-gas efficiency ^c	80.5	85.5	81.8	80.5	77.4	82.8
Carbon-to-electricity efficiency ^c	44.9	46.7	46.0	45.0	43.4	45.4
Coal-to-electricity efficiency ^c	44.5	46.2	43.8	42.8	42.5	44.5

^aKRW, Kellogg-Rust-Westinghouse; CE, Combustion Engineering.

^bIn situ (Cases 1 and 1a) refers to limestone addition to the KRW gasifier for sulfur removal. Cold gas cleanup is at 315 °C (600 °F) for the KRW system (Case 1) and 230 °C (450 °F) for the CE system (Case 3). Hot gas cleanup is at 565 °C (1050 °F) for all systems and assumes use of candle filters for particulate removal and the General Electric barium titanate system for sulfur removal.

^cAll efficiencies are given as percentages on a higher heating value basis (see Glossary). The carbon-to-gas efficiency refers to the production of cleaned fuel gas, excluding carbon losses. The coal-to-gas efficiency includes all losses. Carbon conversion efficiencies for the KRW system are 99.0 percent for the in situ sulfur removal (Cases 1 and 1a), 95.2 percent without in situ removal (Cases 2 and 2a), and 98.0 percent for the CE system (Cases 3 and 3a).

Source: Gilbert/Commonwealth, Inc. (1994).

Table 6-3 Gasifier Systems Being Demonstrated for Power Generation Under the CCT Program

Gasification Technology	Name, Location	Oxygen or Air-blown	Hot or Cold Gas Cleanup	Total Project Cost ^a (millions of current \$)	DOE Cost Share ^b (millions of current \$)
Entrained-flow	Texaco, Polk Power Station, Tampa Electric Co.	Oxygen	Cold plus 10 percent hot	241.5	120.7
	Destec, Wabash River Station, PSI Energy, Inc.	Oxygen	Cold	396.0	198.0
	ABB Combustion Engineering, Lakeside Station, City Water, Light and Power	Air	Hot	270.7	129.4
Fluidized-bed	KRW, Tracy Station, Sierra Pacific Power (Pinon Pine)	Air	Hot	270.0	135.0
	MCTI Pulse Combustor, Caballo Rojo Mine	Air	Hot	37.3	18.7
	Tampella U-Gas, Toms Creek Mine, Va.	Air	Hot	196.6	95.0
Moving fixed-bed	British Gas Lurgi, slagging, Camden IGCC, Duke Energy Corp.	Oxygen	Cold	780.0	195.0

^aTotal value of projects is \$2,192.1 million.

^bTotal DOE cost share is \$891.8 million (40 percent).

Source: DOE (1994b).

Table 6-4 DOE Budget for Surface Coal Gasification (thousands of current dollars)

	FY 1993	FY 1994	FY 1995 (request)
Design and construction of advanced hybrid gasification systems	5,350 ^a	8,205	10,140
Systems analysis and small-scale experimentation for syngas and hydrogen	765	453	395
Modeling, advanced gasification concepts, and catalytic gasification	1,447	471	410

^aInvolves industry participation with 20 percent cost share.

Source: DOE (1994a).

Table 6-5 F-T Process Development and Commercial Activities

Participants	F-T Process	Status
Sasol	Lurgi/Sasol Arge fixed-bed process; waxy product from coal feed	Commercial operation at Sasol I for 40 years
Sasol	Sasol Synthol circulating fluid bed; light olefins and olefinic naphtha from coal feed	Commercial operation
Sasol	Slurry-phase process using coal feed; 30-44 percent paraffins, 50-64 percent olefins; 7 percent oxygenates	Commercialized in 1993 after 10-year development program. Plant capacity is 2,500 bbls/day.
Shell Oil Company	Shell middle distillate fixed-bed synthesis using gas feed	Bitulu plant in Malaysia became operational in 1993; capacity is 12,000 bbl/day.
Mobil R&D Corporation/DOE	Slurry F-T reactor with gas feed using ZSM-5 catalyst	Major development in late 1980s
Exxon	Slurry hydrocarbon synthesis with gas feed and product hydroisomerization	Program completed in 1993 demonstrated processes at scale of 200 bbl/day; ready for large-scale commercialization.
Statoil	Gas to middle distillate slurry process	Pilot plant stage
DOE plus industrial partners ^a	Slurry-phase F-T technology using coal feed	Demonstrated at LaPorte facility in 1992

^aAir Products, Exxon, Shell, and Statoil.

Electric Power Generation

A major part of the DOE effort in the Office of FE is directed toward development of coal-fired electric power generation systems. The DOE program sponsors coal technology development from basic research through engineering, proof-of-concept testing, and commercial-scale demonstration. These efforts include R&D on components that are engineered and designed to operate in an integrated fashion in advanced power generation systems. For example, IGCC electric power systems include components such as advanced coal gasifiers, high-temperature gas cleanup systems, and advanced gas turbines.

This chapter focuses on the main coal-based electric power systems under development in DOE and industry programs—namely, pulverized coal-based systems, fluidized-bed combustion systems, and integrated gasification-based systems. Other concepts, including magnetohydrodynamics and direct coal-fired heat engines, also are discussed. In each case the main emphasis is on identifying technical issues, risks, and opportunities likely to influence future development activities by DOE and other organizations. Two key components of many of these systems—combustion turbines and emission control technologies—are then discussed separately. Complementing the R&D directed toward improvements in coal-based electric power systems, the DOE has engaged in extensive technology demonstration through its CCT program (see chapters 2 and 8). Relevant CCT demonstration activities are also addressed in this chapter.

DOE's programs in coal-based power generation focus on advanced technologies that can enable utilities to meet future environmental requirements while containing electricity costs. Thus, advanced power systems must not only produce significantly lower emissions than current coal-fired plants but also must compete economically with other future options. Higher efficiencies in the new technologies will contribute not only to lower fuel costs but also to improved environmental performance for a given power output. DOE's research goals for advanced power systems performance and cost were shown earlier in Table 2-3. Later sections of this chapter include discussions and assessments of goals for individual power generation technologies. Budget data are taken from the FY 1994 and FY 1995 congressional budget requests (DOE, 1993b, 1994d). The committee's comments on DOE's overall strategic objectives for advanced power systems are provided in Chapter 10.

PULVERIZED COAL SYSTEMS

Background

Pulverized coal-fired electric power generation involves reducing coal size to a powder and conveying it with combustion air into a boiler where it is burned. The heat released evaporates water flowing in tubes in the boiler walls to form high-pressure, high-temperature steam, which is used to drive a turbine connected to an electric generator. The steam is then condensed back to a liquid and returned to the boiler to repeat the cycle (called the Rankine cycle). A wide range of coals may be combusted in pulverized coal boilers; however, units designed to burn a variety of coals are more costly than units using a more uniform fuel. Coal cleaning is widely practiced, usually at the mine, to reduce the coal ash and sulfur content and to raise its heating value, thus providing a more uniform fuel supply (see Chapter 5). Pulverized coal combustion has been practiced for many decades, and there is an extensive literature on boiler and system designs.

State of the Art

The overall efficiency of a pulverized coal power generation cycle is affected by many factors, including the thermodynamic cycle design, steam conditions (temperature and pressure), coal grind, combustion air-to-fuel ratio, fuel mixing, air leakage into the system, cooling (condenser) water temperature, and parasitic energy loads for auxiliary equipment such as grinding mills, pumps, fans, and environmental control systems. The net thermal efficiency (conversion of fuel energy to electricity leaving the plant) of U.S. coal-fired generating plants operating today averages 33 percent (EIA, 1993). However, newer state-of-the-art plants with full environmental controls have efficiencies of 38 to 42 percent, the higher values corresponding to new supercritical steam units operating in Europe. Supercritical steam units operate at much higher temperature and pressure conditions than subcritical steam units, thus achieving higher overall efficiency. U.S. experience with early supercritical units installed in the 1960s and 1970s was generally unfavorable because of lack of operator experience and reliability and maintenance problems. Most U.S. coal plants today employ subcritical steam conditions, which give lower efficiency (typically 36 to 37 percent). Some early supercritical units, however, are still operating satisfactorily. The most efficient supercritical steam unit operating in the United States is the Marshall 4 unit of Duke Power, which was installed in 1970 with a design efficiency of 40 percent and today operates at a 38 percent efficiency without a FGD (flue gas desulfurization) unit (Electric Light and Power, 1993). Typical capital costs of modern U.S. subcritical pulverized coal plants equipped with an FGD system range from about \$1,100 to \$1,500/kW, with typical electricity costs of about 40 to 55 mills/kWh.¹

¹Personal communication from C. McGowin, Electric Power Research Institute, to E.S. Rubin, Vice Chair, Committee on Strategic Assessment of DOE's Coal Program, May 1994.

Current Programs

The DOE program to improve pulverized coal-based power generation systems builds on several aspects of current pulverized coal power generation technology that are commercial or near-commercial, including:

- staged air and other combustion modification techniques for NO_x control;
- selective noncatalytic NO_x reduction using ammonia or amines;
- advanced (supercritical) steam conditions to 590 °C (1100 °F), 31 MPa (4,500 psia);
- combined power generation and space heating (hot water);
- combined power generation and process steam (cogeneration);
- coal-water slurry combustion with up to 70 percent coal by weight; and
- expansion turbine electricity generation using steam, hot combustion gases, or heated

air.

As shown in Table 7-1, there are three major components of the DOE RD&D (research, development, and demonstration) program on pulverized coal-based power generation systems: the APC (advanced pulverized coal) systems activity incorporating the LEBS (low-emission boiler system) program and the coal-fired cogeneration program; the IFC (indirectly fired cycle) system activity comprising the externally fired combined-cycle (EFCC) and HIPPS (high-performance power system) programs; and the direct coal-fired heat engines systems activity, incorporating two distinct but related power generation systems—direct coal-fired gas turbines and direct coal-fired diesels. The major technology goals for these programs are summarized in Table 7-1. The FY 1994 budgets for these activities were \$9.1 million for advanced pulverized coal and \$14.4 million for IFCs.

Advanced Pulverized Coal

The LEBS program is focused on improvement in currently available pulverized coal systems through integration with advanced combustion and emissions control technology and state-of-the-art supercritical steam generators. Three power system design teams are currently engaged in cost-shared systems analyses and preliminary design studies. Current designs include use of boiler combustion modification and advanced flue gas treatment systems (e.g., combined SO₂/NO_x removal) to achieve cost-effective emissions control. Selection of final designs for further development is scheduled for early 1995, with engineering development and subsystem testing to be completed in 1996. Proof-of-concept facility construction and operation are scheduled to lead to commercial readiness during the year 2000 (Ruth, 1994).

The related APC coal-fired cogeneration program is aimed at combined electricity and process steam generation in plants of 100 MW electric (MWe) or smaller (i.e., medium industrial and institutional markets). The program addresses constraints imposed on the use of coal in urban areas—including environmental constraints—and the market for process steam.

Indirectly Fired Cycle

IFC systems are advanced coal-based combined-cycle systems intended to compete with oil and gas-fired generation using conventional generation technology familiar to the utility industry. The EFCC variant necessitates the development of an advanced high-temperature ceramic heat exchanger to transfer the heat from coal combustion to an air stream that is the working fluid for a gas turbine. Thus, the turbine is not directly exposed to corrosive and abrasive coal combustion products. The ceramic heat exchanger tubes will allow clean filtered air from the gas turbine compressor to be heated to the turbine inlet temperature, eliminating the need for complex fuel preparation from pulverized coal (LaHaye and Bary, 1994). EFCC will demonstrate the combined cycle including steam generation from the gas turbine and combustion exhaust gases, using current postcombustion emission controls (e.g., FGD plus fabric filter). Subsequent development of HIPPS will incorporate a new high-temperature advanced furnace—also requiring development—that integrates combustion, heat exchange, and emission controls. Although there is no consensus that DOE's goal for NO_x emissions (Table 7-1) can be met by application of advanced state-of-the-art staged combustor technologies, some optimism has been expressed.² A major incentive is to avoid the additional cost of flue gas treatment (e.g., selective catalytic reduction) to meet the emissions goal.

Direct Coal-Fired Heat Engines

DOE's direct coal-fired heat engines program is directed toward commercialization by the private sector of two types of coal-fired engines—a direct-fired gas turbine and a direct-fired diesel engine. The program is aimed at burning coal-water slurry fuels in a combustion turbine by using a sufficiently clean fuel or modifying the turbine. The program is intended to develop modified diesel engines to burn coal-water slurry fuels. Both programs were completed in 1993 and are not part of ongoing DOE activities.

Technical Issues, Risks, and Opportunities

Central station power generation technology using pulverized coal is commercially mature and widely implemented in industrialized countries around the world. The large base of existing capacity and expertise provides a strong incentive to seek environmental, efficiency, and cost improvements by enhancing pulverized coal technology.

DOE's program goals for the LEBS system offer thermal and environmental performance goals comparable to the capabilities of state-of-the-art pulverized coal technology today (see Chapter 3), while EFCC and HIPPS offer a potential for significantly higher efficiencies. However, numerous technical challenges must be overcome if the program's environmental and efficiency goals for EFCC and HIPPS are to be met simultaneously with the cost goals,

²Personal communication from Janos M. Beer, Massachusetts Institute of Technology, to John P. Longwell, Chair, Committee on the Strategic Assessment of the DOE's Coal Program, July 25, 1994.

especially for the higher-efficiency systems. Some of the major technical challenges, well recognized by DOE, include development of key system components, notably a specialized ceramic heat exchanger for EFCC, a high-temperature advanced furnace for HIPPS, and reliable low-emission slagging combustor technology.

An example of the technical challenges facing DOE is illustrated by the heat exchanger requirements for the EFCC system. Experimental studies in the 1940s on open-cycle, indirectly fired gas turbines using metallic heat exchangers did not allow sufficiently high turbine inlet temperatures for economic power production (Orozco, 1993). The use of ceramic materials may permit higher operating temperatures and resulting system efficiencies, but significant materials technology development is still required to achieve the performance targets projected in Table 7-1. The exit air temperature from current ceramic heat exchangers is limited by materials constraints (see Chapter 9) to approximately 1100 °C (2000 °F), significantly below the inlet temperatures of 1290 °C (2350 °F) for state-of-the-art turbines, or 1370 °C to 1425 °C (2500 °F to 2600 °F) for advanced turbines. If development of a high-temperature, high-pressure ceramic heat exchanger proves not to be feasible either technically or economically, a compromise solution may be considered where natural gas is used to reach a high turbine inlet temperature. In one scoping design study (Bannister et al., 1993) the heat supplied from natural gas was on the order of 30 to 40 percent of the heat supplied by coal for a ceramic heat exchanger limited to an operating temperature of 1100 °C (2000 °F) or less.

In addition to these specific technical challenges, the DOE program emphasizes a "unified approach," "synergies," and integration of components and subsystems to achieve target efficiencies and reduce the cost of the commercialized technology (DOE, 1993a). To achieve these opportunities, substantial development and demonstration of integrated systems still remains.

Findings

Pulverized coal combustion systems are an established and mature technology for power generation, with comparatively limited opportunity for further performance enhancements based on a simple Rankine steam cycle relative to advanced combined-cycle systems. Thus, the market niche for the LEBS system is not clear. Environmental performance is comparable to state-of-the-art commercial systems available today, and the efficiency of the LEBS system is comparable to today's supercritical steam units. Potentially lower costs through system integration, however, could be of interest for near-term power generation markets.

The indirectly fired combined-cycle systems have the potential for significantly higher efficiency. However, this higher efficiency depends on providing gas heated to 1260 °C to 1425 °C (2300 °F to 2600 °F), while heat exchanger materials are currently limited to 1100 °C (2000 °F). Increasing this temperature is a major materials challenge. The fallback strategy of depending on natural gas for increasing the gas temperature could provide an interim system.

FLUIDIZED-BED COMBUSTION

Background

Fluidized-bed combustion (FBC) technology consists of forming a bed of finely sized ash, limestone (for sulfur removal), and coal particles in a furnace and forcing combustion air up through the mixture, causing it to become suspended or fluidized. The height of bed material suspended above the bottom of the furnace is a function of the velocity of the combustion air entering below the bed. Atmospheric "bubbling-bed" FBC technology has a fixed height of bed material and operates at or near atmospheric pressure in the furnace. In atmospheric circulating FBC technology, the combustion air enters below the bed at a velocity high enough to carry the bed material out of the top of the furnace, where it is caught in a high-temperature cyclone and recycled back into the furnace. This recycling activity improves combustion and reagent utilization. In all AFBC (atmospheric fluidized-bed combustion) designs, coal and limestone are continually fed into the furnace and spent bed material, consisting of ash, calcium sulfate, and unreacted or calcined limestone, is withdrawn at the rate required to maintain the proper amount of bed material for fluidization.

The amount of coal fed into the bed is approximately 2 to 3 percent of the total weight of the bed material. The fluidization of the bed and the relatively small amount of coal present in the bed at any one time cause good heat transfer throughout the bed material, and the resulting bed temperature is relatively low, about 800 °C to 900 °C (1470 °F to 1650 °F). The fluidization and relatively low bed temperature enhance the capture of SO₂ emitted during combustion and retard the formation of NO_x. The features of in-bed capture of SO₂ and relatively low NO_x emissions, plus the fluid bed's capacity to combust a range of different fuels, are the main attractions of FBC as a power generation technology. Under some operating conditions, AFBC units also may produce higher levels of organic compounds, some of which may be potential air toxics. Current studies also indicate that AFBC units emit higher levels of N₂O—a greenhouse gas—than other combustion systems (Takeshita, 1994).

AFBC technology has been in commercial use worldwide for well over 50 years, primarily in the petrochemical industry and in small industrial steam generators that are a tenth to a hundredth the size of commercial power plant generators. In the United States, development of AFBC technology began in 1965, when DOE contracted for development of a low-cost, industrial-sized AFBC unit. AFBC development in the U.S. power generation sector began in the early 1980s, with support from the private sector, including EPRI (Electric Power Research Institute), and DOE. A 20-MW bubbling bed AFBC unit was constructed and operated by the Tennessee Valley Authority and EPRI beginning in 1980 and concluded in 1987. During this same period, four AFBC demonstration projects ranging in size from 80 to 160 MW were implemented as either retrofits or repowering of an existing unit. As a result of these demonstrations and similar installations abroad, AFBC technology became commercial by the end of the 1980s for industrial steam generation, cogeneration, and utility-scale applications.

The next generation of FBC technology operates at pressures typically 10 to 15 times higher than atmospheric pressure. Operation in this manner allows the pressurized gas stream from a pressurized fluidized-bed combustion (PFBC) unit to be cleaned and fed to a gas turbine. The exhaust gas from the turbine is then passed through a heat recovery boiler to produce steam.

The steam from the PFBC unit and that from the heat recovery boiler are then fed to a steam turbine. This combined-cycle mode of operation significantly increases PFBC system efficiency over the AFBC systems. If the PFBC unit exhaust gas can be cleaned sufficiently without reducing its temperature (i.e., by using hot gas cleanup systems), additional cycle efficiency can be achieved.

Development of PFBC has been under way since 1969, when the British Coal Utilization Research Association began operating a PFBC test unit at Leatherhead, England. A significant portion of the test work conducted there over the next 15 years was supported by EPA, DOE, and the U.S. private sector. In the early 1980s a number of other PFBC test and pilot facilities were constructed in the United States and Europe. The United States, the United Kingdom, and the Federal Republic of Germany under the auspices of the International Energy Agency constructed an 85-MW thermal (MWt) PFBC unit that was placed in service in 1980. Early cooperation between the American Electric Power Service Company and ASEA STAL (now ASEA Brown Boveri, with its subsidiary ABB Carbon) led, in 1982, to the construction of a 15-MWt PFBC component test facility now located in Finspong, Sweden (Miller et al., 1982).

State of the Art

AFBC technology has achieved commercial acceptance, while PFBC technology is currently undergoing commercial demonstration. As of mid-1993, 622 AFBC units (293 bubbling bed and 276 circulating bed) were operating worldwide, with an average steam capacity of 235,000 lb/hr. About 43 percent of the steam capacity and 35 percent of the total number of units were sold in North America, mainly in the United States. EPRI has estimated that 75 percent of the U.S. capacity is circulating FBC technology. Independent power producers, rather than investor-owned utilities, have pushed the development of AFBC in the United States. The present generation of AFBC technologies has no difficulty meeting the current NSPS for steam electric power plants or industrial sources.

PFBC technology is in the early stages of commercialization. Four PFBC units of less than 80 MW, two in Sweden, one in Spain, and one in the United States, have been placed in operation in the past four years. A fifth 71-MW unit is in initial operation in Japan. The DOE CCT program is sponsoring an 80-MW circulating PFBC project expected to be in commercial operation in mid-1997 (DOE, 1994a).

In addition, the CCT program has selected a 95-MW second-generation PFBC project for funding. This advanced PFBC system will involve partial gasification of the coal, with the resulting fuel gas going to a topping combustor along with cleaned gases from a circulating unit that will receive char from the gasifier. Electricity is generated from the topping combustor and from a steam cycle coupled to the PFBC unit. An advanced system for hot gas cleanup will also be used in the demonstration. A fully integrated second-generation PFBC system is also scheduled to be tested at the 8-MWe level at the Power Systems Development Facility under construction in Wilsonville, Alabama, sponsored by DOE, Southern Company Services, and EPRI. This PFBC testing will evaluate the integration of all of the components in the PFBC system, with emphasis on the integration of hot gas cleanup ceramic filters and gas turbines (DOE, 1993a).

Current Programs

DOE funding for AFBC technology development ended in FY 1992. The current PFBC program is aimed at developing second-generation systems for electric power generation with performance goals as summarized in Table 7-2. The FY 1994 Office of Fossil Energy budget for PFBC was \$24.1 million.

Technical Issues, Risks, and Opportunities

AFBC systems, either in the bubbling bed or circulating bed configuration, constitute a commercially mature technology, and DOE has contributed in a major way to its success. To further enhance its commercial application, manufacturers need to refine the technology to achieve lower capital costs compared with modern pulverized coal (PC) plants, improved environmental performance, and improved operating efficiency. However, the time period for competitive application of this technology in the U.S. electric power production sector is now and in the immediate future. The availability and cost of natural gas, along with competition from modern PC plants, will dictate whether AFBC continues to be a technology of choice for environmental compliance and new capacity additions by independent power producers. Because most new coal plants currently are being constructed outside the United States, the greatest opportunity for this technology is in developing countries.

PFBC technology is just beginning to be commercially demonstrated and offers significant design, performance, environmental compliance, and cost advantages over AFBC technologies. As noted earlier, a second generation of PFBC technology offering additional performance (efficiency) benefits is entering the pilot and demonstration phase. These systems employ a coal pyrolyzer to produce a fuel gas that is burned in the turbine topping cycle. Since only a portion of the coal is gasified, this design has the potential for higher efficiencies than IGCC systems, where all of the coal is gasified. Maude (1993) estimates that the efficiency advantage may be approximately four percentage points. Because PFBC operates at a higher pressure and increased efficiency compared with AFBC, the same power output can be achieved with a unit that requires less land area (i.e., smaller "footprint" of equipment). The steam flows for PFBC units also are compatible with steam turbines at existing power plants. Thus, the technology is especially attractive for repowering existing units at existing power plant sites, avoiding the need and difficulty of developing new sites. The higher cost of equipment operating at higher pressures and temperatures is partially offset by the reduced equipment size and higher efficiency. Efficiencies on the order of 39 to 42 percent can be achieved with newer PFBC designs, compared with 34 percent efficiency for AFBC. EPRI estimates the capital cost of a 340-MW bubbling bed supercritical PFBC boiler (42 percent efficiency) at \$1,318/kW (in 1992 dollars), with a total levelized cost of 37 mills/kWh (80 percent capacity factor, eastern bituminous coal) (EPRI, 1993a).

Substantially higher efficiencies (45 to greater than 48 percent) are expected from second-generation PFBC systems. It is questionable whether the advanced PFBC systems can achieve DOE's goal of 20 to 25 percent reduction in electricity cost as well as capital cost reductions relative to current PC plants. In general, the higher degree of complexity of advanced systems

makes it likely that capital costs will tend to increase rather than decrease, although the resultant efficiency gains will have a positive effect in lowering the cost of electricity. At present, however, there remains considerable uncertainty as to the future costs of advanced power systems.

One of the key performance and cost uncertainties for advanced PFBC systems is the development of hot gas cleanup technology. Reliable hot gas particulate cleanup plus advanced (1370 °C [2500 °F] or higher) turbine systems will be required for PFBC technology to achieve DOE's projected performance potential of more than 50 percent efficiency while meeting environmental compliance requirements. At the present time these technologies are under development. The status of hot gas cleanup technology and advanced turbine systems (ATS) is discussed later in this chapter.

Related issues concern the development of adequate SO₂ and NO_x controls and their associated costs. Current DOE flowsheets for advanced PFBC systems are beginning to incorporate the possible need for selective or nonselective catalytic reduction systems for NO_x control in addition to the combustion controls inherent in FBC systems. Added NO_x controls would increase the base cost of the plant. Also of concern is the reagent requirement for sulfur removal and the resulting solid waste generation. As elaborated later in this chapter (see "Emission Control Technologies"), increasingly stringent requirements for SO₂ removal are becoming more difficult or more costly to achieve with fluidized-bed systems, which also generate larger quantities of solid waste than new PC plants with FGD. An increase in solid waste generation is inconsistent with DOE's goals for advanced power systems, which seek sizeable reductions in solid waste. Thus, there is a need to demonstrate efficient environmental designs and to address potential by-product markets for spent reagent in order to reduce solid waste impacts.

Findings

AFBC systems are a mature commercial technology, and, as such, DOE is no longer pursuing additional R&D on this technology. Significant performance improvements are expected for PFBC systems, which are now beginning to be commercialized. The DOE performance goals for the PFBC program appear to be reasonable for the first- and second-generation systems. The capital cost goals for all generations appear to be optimistic, especially as the number of components and complexity of the system are increased for the second-generation and improved second-generation systems. A major uncertainty still facing PFBC systems is the reliability and cost of hot gas particulate controls. Reduction of solid wastes, economical high SO₂ removal efficiencies, and generation of supercritical steam in a fluidized bed are other issues to be addressed.

INTEGRATED GASIFICATION COMBINED-CYCLE SYSTEMS

Background

Coal gasification is a method of producing a combustible gaseous fuel from almost any type of coal. The current status of gasification technology and opportunities for efficiency enhancement have been discussed in Chapter 6. Gasification is a key step for advanced conversion of coal to electricity using IGCC systems. An IGCC power plant is a gasification facility coupled to a gas-fired combined-cycle unit. Based on current environmental control capabilities, IGCC offers a coal-based power technology with low emissions, high thermal efficiency, and the potential for phased construction—that is, building simple-cycle natural-gas-fired combustion turbines first, then converting to combined-cycle, and finally adding coal gasification as gas prices increase or gas availability deteriorates. Future advances in gasification-based power production are linked to increases in gas turbine firing temperature, hot gas cleanup of the fuel gas, coproduction of both chemicals and electricity, improved gasifier designs, and integration of gasification with advanced cycles and fuel cells.

State of the Art

Components of IGCC technology have been under development for some time, and several competing coal gasification processes now have successful commercial-scale operating records (see Chapter 6). These include the Texaco, Shell, and Destec (formerly Dow) entrained-flow processes and the Lurgi moving-bed process. Other gasification processes have been successfully tested at pilot scale and are ready for scale-up to commercial size, including the Prenflo entrained-flow, the British Gas/Lurgi moving-bed, and the KRW and the high-temperature Winkler fluidized-bed processes.

The IGCC concept was first successfully demonstrated at the 100-MW scale at Southern California Edison's Cool Water Station in Daggett from 1984 to 1989 using the Texaco entrained-flow coal gasification process. Destec is currently operating a 160-MW IGCC plant in Plaquemine, Louisiana, using a two-stage, entrained-flow coal gasification process. In the Netherlands, SEP (the joint authority for electricity production) has begun operation of a 250-MW IGCC plant based on the Shell entrained-flow coal gasification process. Each of these plants employs gas turbines with firing temperatures of about 1100 °C (2000 °F).

Table 7-3 summarizes the performance and economics for a hypothetical 500-MW first-generation IGCC plant employing a state-of-the-art, oxygen-blown, entrained-flow gasification process to provide fuel gas to advanced combustion turbines. The IGCC plant is fueled with an eastern bituminous coal, is highly integrated, and employs cold gas cleanup. The cost for current systems is significantly higher than the DOE goals for advanced systems shown later in Table 7-4.

Technical Issues, Risks, and Opportunities

First-generation IGCC plants have already demonstrated outstanding operability and environmental performance at commercial scale. The key issue for these technologies is the impact of high capital cost on economic competitiveness. Chapter 6 discussed technical issues and opportunities related to coal gasifiers. Reductions in the capital costs of IGCC systems can be accomplished through simplification and optimization of the process, economies of scale, and/or through thermal efficiency gains. Future improvements to the economics of IGCC, therefore, are linked mainly to development of advanced gas turbines with firing temperatures over 1370 °C (2500 °F) and secondarily to development of reliable hot gas cleanup schemes. Both of these subjects are discussed later in this chapter. As noted in Chapter 6, energy losses in gasification and gas cleanup amount to about 15 to 20 percent of the total coal energy input, resulting in a loss of 5 to 10 percentage points in power generation efficiency. Thus, improved gasifier designs with lower energy losses also can contribute to overall efficiency improvements. Current systems studies suggest that the integration of gasification with advanced cycles, such as the humidified air turbine, and compressed air storage with humidification, also has the potential to reduce capital costs and provide competitive intermediate-load capacity (EPRI, 1991b, 1993c,d). The highest-efficiency system proposed by DOE and based on gasification is an integrated gasification advanced-cycle (IGAC) system based on a humidified gas turbine (DOE, 1993a).

Current Programs

DOE's program goals for IGCC systems are summarized in Table 7-4. The FY 1994 Fossil Energy coal program authorization for IGCC was \$27.2 million. The DOE CCT program also includes several gasification-based power projects, which represent the state of the art and encompass both entrained-flow and fluidized-bed gasification systems. Table 6-3 summarized the status of these CCT projects. The completion of the CCT programs in about five or six years will provide the data and experience for subsequent commercial IGCC plants to be employed beyond the year 2000. Table 7-5 summarizes the major European IGCC projects in progress. Except for the Buggenum project (Table 7-5), all the combustion turbines are 1300 °C class (2350 °F). Other IGCC projects are also planned for Asia.

Findings

IGCC offers a coal-based power technology with low emissions, the potential for higher thermal efficiency, and the capability for phased construction. First-generation IGCC plants have already demonstrated outstanding operability and environmental performance at commercial scale. The key issue for these technologies is the high capital cost and its impact on economic competitiveness.

Gasification is an enabling technology that allows the use of very high efficiency energy conversion devices—such as high-temperature gas turbines and fuel cells—for power production

in combined-cycle systems. Reductions in capital costs can be accomplished through process simplifications, economies of scale, and thermal efficiency improvements. With completion of the DOE CCT programs and the major European demonstration projects in the next five to six years, areas for continued improvements to the gasification technologies and IGCC process can be identified to reduce the capital cost and enhance the economic competitiveness.

INTEGRATED GASIFICATION FUEL CELL SYSTEMS

Background

Fuel cells are electrochemical energy conversion devices that convert the chemical energy in a fuel and oxidant directly to electricity without direct combustion. They can be thought of as "gas batteries" where the electrochemically active materials are gases that can be ducted to the electrodes from outside the battery case. The reaction products are also gases and can be removed similarly. A fuel cell can be "discharged" continuously to produce electricity so long as the reactants are supplied and the products removed.

The fuel cell has many of the same features as a battery. The power production takes place at a constant temperature; hence, it is not constrained to the theoretical upper limit for heat engines (known as the Carnot cycle efficiency). Thus, fuel cells potentially can be much more efficient than combustion-based systems. Environmentally, the electrochemical reactions do not involve direct combustion, so thermal NO_x production is negligible. Reactants are consumed exactly in proportion to the electric energy output, so the efficiency remains high even when the level of power production is reduced.

In practice, fuel cell system efficiencies remain limited by energy losses and inefficiencies inherent in most engineered systems. Continued R&D is aimed at reducing these losses to improve overall efficiency. An attraction of fuel cell systems is that natural gas or coal-derived fuel gas both make suitable fuels for running a fuel cell system. Interest in fuel cells as an energy conversion system stems primarily from the fact that they offer the highest efficiency and lowest emissions of any known fossil-fueled power generation technology.

State of the Art

Fuel cells first came to public attention in the 1960s because of their importance in the manned space program. Today, commercially available fuel cell systems are based on phosphoric acid fuel cell (PAFC) technology and are configured for small-scale commercial and residential cogeneration applications. These systems use natural gas or other light hydrocarbons as fuel. They typically yield 36 percent net electrical efficiency and over 70 percent total efficiency if all thermal energy is used (e.g., for space heating). This type of fuel cell operates at approximately 200 °C (400 °F), too low a temperature for the thermal energy to be efficiently converted to useful work in a bottoming cycle. ONSI Corporation has delivered nearly 60 of the 200-kW PAFC cogeneration systems. Plant reliability and availability based on experience to date have been outstanding.

Molten carbonate fuel cells (MCFC) using a molten alkali-metal carbonate electrolyte operate at approximately 650 °C (1200 °F), a temperature where rejected heat can be used efficiently in a bottoming cycle and where conventional materials still can be used for the balance of plant equipment. This type of fuel cell power plant is just entering the demonstration phase of development. Power plants from several U.S. and Japanese manufacturers ranging in size from 200 kW to 2 MW are planned to be in operation in 1995. These plants are expected to enter the utility market as 1- to 5-MW units, natural gas fueled, with electrical generation efficiency greater than 50 percent (without a bottoming cycle) by the year 2000. In larger sizes, with steam or gas bottoming cycles, efficiency will be 60 percent or higher when using natural gas fuel (EPRI, 1993b).

The solid oxide fuel cell (SOFC), of which the basic building block is an oxide-ion conducting ceramic electrolyte, operates at an even higher temperature (980 °C [1800 °F]). The potential for future cost reduction makes SOFCs attractive. The most successful system to date is the Westinghouse tubular design that has been operated in units of up to 20 kW for over 6,000 hours. The key fabrication issue is the use of chemical vapor deposition to fabricate these tubular components, which is expensive. A great deal of current research is focusing on simpler planar systems that show promise for less expensive fabrication techniques. The largest planar unit under test at this time is 1 kW. It is anticipated that the scale will be increased to 10 kW within one year.

Fuel cells integrate readily with coal gasifiers. Such IGFC systems are potentially the most efficient and least polluting method to generate electricity from coal. Characteristics of the three types of fuel cells integrated with coal gasifiers are given in Table 7-6. EPRI (1993b) estimates that integrated gasification molten carbonate fuel cells based on current state-of-the-art entrained-flow gasification will have a full-load efficiency around 50 percent. Because of energy losses of about 15 to 20 percent inherent in gasification (see Chapter 6), major advances in gasification technology will be required to meet the DOE IGFC efficiency goal of 60 percent or greater. The total capital requirement is approximately \$1,900/kW, and the cost of electricity is not yet competitive with other gasification-based power systems. The capital cost must be reduced by approximately 20 percent to make the systems competitive. This is generally considered feasible, with technological advances already planned for the fuel cell and gas cleaning subsystems within the plant.

Technical Issues, Risks, and Opportunities

IGFC will not materialize for utility-scale electricity generation until the fuel cells are first used commercially as small-scale distributed generators on natural gas. This in turn requires demonstration that engineering development issues are resolved and that the fuel cells themselves have the reliability and durability necessary for utility service. Since demonstration projects are costly, there is the risk that commercial firms could fail because of insufficient funds to complete the necessary demonstrations of their technology.

Molten carbonate systems offer the most attractive near-term opportunities for utility applications. For the long term, there is some risk that the MCFC manufactured cost will not decrease to the levels needed for widespread use in distributed generation and in coal-based

IGFC systems. Independent studies of MCFC manufacturing methods, however, show that stack costs similar to combustion turbines (i.e., \$250/kW) are possible in production quantities of 300 to 400 MW per year (EPRI, 1992b). Manufacturing costs now are about 10 times higher—partly because manufacturing facilities are still about 100 times smaller. Studies indicate that the balance of plant costs will exceed the stack costs in commercial fuel cell power plants. A systematic market-entry program is the key to overcoming the high-cost, low-volume hurdle of new technologies.

For applications with coal, contamination of the fuel cell by trace coal constituents is the primary area of concern. Substances such as chlorides, sulfides, arsenic, alkali metals, zinc, cadmium, lead, and mercury vapors are capable of poisoning fuel cells and reducing their performance. At present, there is little information on the acceptable levels of these contaminants. High-temperature purification systems that can reduce some trace contaminants to very low levels are under development (Pigeaud, 1994).

Current Programs

DOE's program goals for IGFC systems are presented in Table 7-4. The FY 1994 budget authorization for fuel cells RD&D—which is now in the natural gas program—was \$51.8 million. DOE is supporting technology and demonstrations of MCFC by two manufacturers at approximately \$30 million/year, with EPRI and GRI collaborating at approximately \$5 million/year each. One application is a 2-MW plant for the Santa Clara, California, municipal electric utility grid; the other is a 250-kW pilot plant at Unocal's research center. Both demonstrations are expected to begin operation in the first half of 1995.

EPRI also has been sponsoring testing of a 20-kW MCFC stack on a coal-gas slipstream at the 160-MW Destec IGCC plant in Plaquemine, Louisiana, since late 1993. To date, this test has shown no indication that coal-derived gas presents any difficulty in use. However, long-term data remain to be collected.

DOE is supporting SOFC R&D at approximately \$18 million per year, with EPRI and GRI each contributing approximately \$1 million/year. For the tubular SOFC, the effort is focused on scale-up and demonstration. For the planar SOFC, the emphasis is on fundamental materials and manufacturing issues at a number of industrial, specialty research, and academic organizations. No prototype or commercial-scale plants are envisioned for three to four years for the planar SOFC. Many cost and manufacturing issues remain to be resolved in this time period.

While both the MCFC and SOFC systems ultimately will operate on gasified coal, at this time there are no commercial-scale or demonstration projects of coal-based IGFC.

Findings

The current U.S. fuel cell program is focused on the use of natural gas, although IGFC systems running on coal-derived fuel gas are envisioned by DOE as a logical follow-on. Such systems offer the highest efficiency and lowest emissions of coal-based technologies, but their

cost currently is high. The initial demonstration of MCFC projects by two manufacturers is under way at the 250-kW and 2-MW scales using natural gas. However, it is not likely that these demonstrations will be capable of resolving all technical issues.

At a reasonable rate of growth in demand for fuel cells, manufacturing costs for MCFC stacks could drop an order of magnitude to the \$250/kW range. A systematic market entry program is the key to overcoming the high-cost, low-volume hurdle. Therefore, planned DOE support of balance of plant cost reduction development is the logical next step in fuel cell technology development, since these costs are larger than the fuel cell stack costs.

Future development of coal-based IGFC systems will depend on the success of current gas-based technology and on the resolution of key technical issues, particularly the types and levels of contaminants in coal-derived fuel gas that must be controlled.

MAGNETOHYDRODYNAMIC POWER GENERATION

Background

MHD (Magnetohydrodynamic) power generation is a method for converting thermal energy directly to electric power. The MHD generator is based on the concept of using a flowing ionized gas or liquid metal heated by fossil and/or nuclear fuel as the moving conductor in an electric generator. By using this very high temperature (typically 2300 °C [4170 °F]) working fluid directly, the MHD generator serves as a topping cycle that achieves high overall efficiency (60 percent or more) when combined with additional power generation from a steam cycle fueled by the hot exhaust gas.

The simplest MHD generator is based on a linear geometry—the hot combustion gas flows through a linear duct or channel. A magnetic field provided by high-strength electromagnets at right angles to the gas flow induces an electric field at right angles to both the gas flow and magnetic fields. A "seed" material such as sodium or potassium is added to the combustion gas to improve its electrical conductivity. If electrodes are then placed on either side of the channel and connected through an external electrical load or resistance, current will flow through the gas, electrodes, and external load, providing power. In addition to MHD systems based on the flow of high-temperature seeded combustion gases, other proposed schemes for MHD power generation employ flows of liquid metals, combinations of liquid metals with gas bubbles, and alkali-seeded noble gases (or pure nitrogen or hydrogen) that ionize at much lower temperatures than do combustion gases (Angrist, 1976).

State of the Art

Most of the development work on MHD power generation has been on open-cycle combustion gas systems. These projects received significant funding in the United States (from DOE) and in the former U.S.S.R. Both projects have now been closed down. In the U.S.S.R. a 25-MW natural-gas-fired system (U-25) provided electricity to the Moscow power grid for several years. The DOE concentrated on smaller-scale coal-fired systems, which included tests

of over 2,000 hours on the lower-temperature heat recovery systems. The proof-of-concept high-temperature combustion and MHD generator sections were run for only about 400 hours. While most of the test performance goals were reached, the long-term high-temperature component durability required for utility applications is still in question. A proposal to DOE's CCT program to scale up to a combined MHD-steam plant of about 75 MW with an efficiency of approximately 31 percent was not selected for funding. Work on a tall-loop liquid metal MHD cycle has been concentrated in Israel, where test loops have been built to prove out the concept. These systems have the potential of 45 percent efficiency, but funding for further development is uncertain.

Technical Issues, Risks, and Opportunities

The open-cycle combustion gas systems as tested would extrapolate to a 500-MW coal-fired MHD plant meeting the federal NSPS for SO₂ and NO_x with an efficiency of up to 45 percent (Lohrasbi et al., 1991). This efficiency potential would drop considerably for smaller power plants. A claimed potential efficiency of 60 percent could only be met with the development of a high-temperature heat exchanger to preheat the combustion air to over 1370 °C (2500 °F), but little development work has been done on this exchanger. Furthermore, economic operation would depend on low-cost seed recovery, but only preliminary work has been accomplished in this area. The durability of the high-temperature MHD channel has not yet been demonstrated, and an integrated plant has not operated at any scale. Relative to other advanced technologies now under development, MHD systems pose much greater technological challenges because of the aggressive thermal environment and system complexity. At the same time, the thermal efficiency advantage of MHD systems has been eroded by more recent developments in other coal-based systems employing advanced gas turbines, fuel cells, and gasifiers.

Current Programs

DOE funding of the MHD proof-of-concept facility ended in FY 1993. FY 1994 funding and that requested for FY 1995 are only for site restoration, and no large-scale follow-on work is planned.

Findings

While a number of important technical goals were met by the DOE MHD program, significant issues were left unresolved, notably operational reliability. No U.S. funding is planned to resolve these remaining issues, since other advanced power systems now offer comparable or superior performance with higher reliability, lower projected cost, lower emissions, and a much lower level of technical risk.

COMBUSTION TURBINES

Background

The combustion turbine is the key power generation component in most advanced coal-based systems. The turbine system consists of a compressor to take combustion air from atmospheric pressure to a pressure of 8 to 16 atmospheres; a combustor burning a fossil fuel (natural gas, light refined petroleum fractions, or coal-derived fuel gas) to produce hot combustion gases; and an expansion turbine to extract work as the high-temperature, high-pressure gas is reduced to ambient conditions. This system is referred to as the Brayton cycle. About two-thirds of the shaft work of the expansion turbine drives the compressor, and the remainder drives a generator to produce electricity. The net power output depends strongly on the turbine inlet temperature, which is limited primarily by materials considerations. Combustion turbines can be designed to burn any of the above-mentioned fuels (provided they are adequately free of contaminants) and to switch from one fuel to another in service.

Two types of combustion turbines are used for electric power generation, namely, heavy-frame and aeroderivative turbines, the latter derived from jet engine technology. Historically, major evolutionary improvements in aircraft jet engine technology have been adapted to heavy-frame utility combustion turbines. In addition, utilities have used aeroderivative combustion turbines for smaller-capacity generation applications. Thus, forecasting the evolution of combustion turbines for power generation is a relatively straightforward matter of assessing current jet airplane engine technology.

State of the Art

Current commercial gas turbine systems offered by U.S. and foreign manufacturers achieve firing temperatures up to 1300 °C (2350 °F), with unit sizes up to about 250 MW. Natural gas and light petroleum liquids are the fuels currently employed for power generation, typically for peak or intermediate loads. The simplest, lowest-cost-per-kilowatt, fossil power plant for peaking duty is the simple Brayton cycle combustion turbine described above. Both aeroderivative and heavy-frame turbines are used this way. Aeroderivative turbines are more efficient in simple-cycle operation because jet aircraft engines are intended to extract maximum energy from the hot combustion gases during the turboexpansion.

A combined-cycle combustion turbine plant, in which a Brayton cycle gas turbine is combined with a Rankine cycle steam generator using the waste heat in the exhaust from the turboexpander, is the most efficient system for a fossil power plant commercially available today. Because relatively little useful energy remains in the expander exhaust of an aeroderivative combustion turbine, the heavy-frame machine has the higher efficiency in combined-cycle operation. Table 7-7 compares the capacities and thermal-to-electric energy efficiency typical of 1300 °C-class (2350 °F-class), heavy-frame, and aeroderivative combustion turbines burning natural gas being sold now or expected for delivery in the mid-1990s.

If the feed gas has been cleaned to a level that will meet air quality standards, oxides of nitrogen (NO_x) are the only emission concern for combustion turbine power generation. Gas

turbine manufacturers have developed dry (no water or steam injection) premixed lean-burn low- NO_x combustors for commercially available gas turbines to achieve NO_x levels of 7 to 25 ppm in the exhaust. As noted earlier (Chapter 3), such levels are required to comply with various state and local regulations, which are far more stringent than the federal NSPS of 75 ppm for gas turbines. Some of the first-generation dry low- NO_x systems, however, are not so effective if operating at low load. Steam injection is another approach used to lower NO_x and simultaneously augment power output by putting more mass through the turboexpander.

Continued evolution of gas turbines is projected with firing temperatures up to 1430 °C (2600 °F). These machines will require further cooling advancements, NO_x reduction improvements, and probably ceramic nozzles and blades in the hottest sections of the hot gas path. The major combustion turbine manufacturers are forecasting commercial availability of such machines (using natural gas) in the 1998 to 2000 timeframe.

Technical Issues, Risks, and Opportunities

Ongoing and future technology improvements can further increase economic application of combustion turbines and broaden the attractiveness of coal utilization in advanced power systems. At this time, however, most of the technical issues and opportunities in gas turbine development remain focused on the use of natural gas. Cleaner fuels and combustion air to keep out corrosive agents, materials to resist corrosion at higher turbine operating temperatures, more sophisticated blade cooling methods (closed-circuit steam cooling, partial cooling of the last-stage blades), and designs for reduced maintenance all will increase reliability over current combustion turbine models and are expected to push combined-cycle efficiencies on natural gas to 53 percent (HHV) or higher by the end of the decade and to 57 percent no later than 2010.

Advancements in hot section cooling designs, construction materials, coatings for oxidation and corrosion resistance, and thermal barrier coatings (see Chapter 9) will be key to increasing combustion turbine firing temperatures and thus further increasing the efficiency of combustion turbines and associated coal-based power generation cycles. Single-crystal alloys—already used in aircraft engines—could advance last-stage turboexpander blading design and thus improve combined-cycle efficiency. A major uncertainty for coal-based applications is the level of fuel gas cleanup needed to protect such advanced turbine designs.

Other technical issues facing application of combustion turbines in advanced coal-based power generation include

- use of medium- and low-Btu fuel gas in combustors, and the effect of gas composition and variability on combustion efficiency and emissions;
 - corrosion and/or deposition on turbine blades;
 - integration of coal gasification with novel combustion turbine thermodynamic cycles;
- and
- potential for catalytic combustion (low NO_x) technology using coal syngas.

Many of these issues are being addressed in the ongoing programs described below. For example, recently reported work at General Electric Company, sponsored by EPRI and DOE,

has confirmed that the combustion of coal gas with heating values below 100 Btu/scf is stable with very low CO emissions if the volumetric ratio of hydrogen to carbon monoxide exceeds unity. NO_x emissions are also significantly below current standards. Control of NO_x emissions from advanced turbines achieving higher firing temperature (and thus producing higher thermal NO_x in air-blown systems) will require further study to determine whether future standards can be met by combustion controls alone or if additional requirements for postcombustion controls will be required.

DOE programs have investigated the corrosion potential of alkali metals on gas turbine blades in both PFBC and IGCC systems. In lower-temperature systems below about 870 °C (1600 °F), little damage has been observed. At higher temperatures, there has been some experimental evidence that fine mineral matter components carried along in the gas phase interact with vapor-phase alkalis to form innocuous solids that do not attack the turbine blades. If the problem turns out to be more severe, blade coating has been identified as the most promising approach for current designs. For higher-temperature advanced turbines (e.g., 1430 °C [2600 °F]), requirements for contaminated removal from coal-derived fuel gas are not yet established.

Issues of system integration for coal-based power plants also remain to be addressed. At the present time, the concept of phased construction is widely viewed as a flexible strategy that can be a cost-effective way to transition the modest capital investment in a combustion turbine from peaking application to mid-load and eventually to baseload. However, there are significant technological and regulatory hurdles to overcome in such a conversion, which must be addressed. For example, a combustion turbine optimized for simple- or combined-cycle gas firing is not optimal for coal-based IGCC operation. Overall, converting to gasified coal lowers the net power plant efficiency by 5 to 10 percentage points—depending on gasifier and cleanup system design—relative to natural gas, primarily due to losses upstream of the turbine (Gilbert/Commonwealth, Inc., 1994).

Finally, turbine design modifications may be needed to take full advantage of integration issues that are unique to coal-based systems. For example, conceptually, integration of coal gasification with gas turbines that have been modified for operation on compressed humidified air from a storage reservoir have the potential to reduce gasification power plant costs by 20 percent. Another advantage to this cycle is that low-level waste heat energy can be reinjected into the cycle through the evaporation of hot water to humidify the high-pressure air. Expensive development efforts, however, will be required to modify existing aeroderivative turbines for this cycle. Systems studies are needed to identify the most promising options, as well as associated risks.

Current Programs

DOE's ATS program—housed in the natural gas program of the Office of Fossil Energy—is a major effort to develop and design high-efficiency combined-cycle combustion turbines. The FY 1994 authorization for this program was \$21.9 million; the FY 1995 DOE request has more than doubled to \$44.9 million. The research is aimed at potential barrier issues, focusing on two primary areas: higher firing temperatures, mainly from improved cooling

concepts and materials, and high-efficiency cycles, aimed at steam cooling, interstage compression cooling, and chemical recuperation. The program aims to provide technology ready for commercial baseload application by 2000 that will be applicable to coal and biomass systems as well as natural gas. DOE is also involved in other cooperative programs with industry, notably the Collaborative Advanced Gas Turbine program involving DOE, EPRI, GRI, and turbine manufacturers.

Increases in the firing temperatures of advanced gas turbines will occur as a result of competitive pressures among manufacturers with a very significant acceleration resulting from the DOE ATS program. The availability of those machines will significantly improve IGCC plant efficiencies, as discussed earlier in this chapter. The higher-temperature turbines will also utilize higher pressure ratios and be significantly larger. As a result, single-train IGCC plants will have outputs of 350 to 400 MW, which will lower specific plant costs through improved economies of scale.

As noted above, the General Electric Company has successfully tested combustion in a General Electric model 7F combustion turbine of a simulated coal-based syngas diluted with H₂O, CO₂, and/or N₂ to HHV (higher heating values) as low as 100 Btu/Scf. These heating values (which are nearly 10 times less than that of natural gas) are comparable to values from the low-Btu fuel gas produced by advanced air-blown coal gasifiers.

Findings

Combustion turbine technology will continue to advance rapidly, driven by aircraft technology improvements but also by power generation application needs. Continued combustion turbine technology improvements and advanced cycles development on natural gas also will benefit the economics of future coal-based systems such as IGCC, PFBC, and IFC designs.

With respect to coal-based applications, key issues and uncertainties include fuel gas cleanup requirements for advanced turbine designs and the design and integration of turbine systems that can optimally accommodate evolution from natural gas to coal gas firing. NO_x emission control requirements and approaches for higher-temperature advanced turbines also remain to be resolved.

EMISSION CONTROL TECHNOLOGIES

Background

The development of environmental control technologies for electric power generation has primarily focused on the control of air emissions resulting from the combustion of fossil fuels. For coal-fired steam-electric generation, the emphasis has been on the control of particulate matter, sulfur dioxide (SO₂), and nitrogen oxide (NO_x) emissions—the three "criteria" air pollutants subject to federal NSPS (see Chapter 3 and Appendix D).

Particulate emissions in coal-based systems arise primarily from coal ash entrained in the flue gas stream (flyash) and from chemical reagents added to control other pollutants, especially SO_2 . Control methods may employ inertial separation, wet scrubbing, electrostatic precipitation, or filtration to separate particles from the gas stream. The electrostatic precipitator (ESP) is the most widely used technology in conventional pulverized coal combustion systems. The particle-laden flue gas passes through an ionizing field, which imparts an electric charge to the particles, allowing them to be collected on an oppositely charged surface. Alternately, a fabric filtration system may be employed to collect particles by passing the flue gas through a fabric filter (baghouse) collector, which operates much like a high-efficiency vacuum cleaner. Current IGCC systems remove particulates by condensing or quenching the raw fuel gas with water (wet scrubbing). First-generation PFBC designs often employ cyclone (inertial) separators in conjunction with an ESP or fabric filter. Advanced IGCC and PFBC systems employ solid (typically ceramic) barrier filters that operate at high temperature and pressure, in contrast to conventional low-temperature devices at atmospheric pressure.

Sulfur dioxide is a component of flue gas resulting from the oxidation of sulfur in the coal during combustion. Sulfur dioxide can be controlled by reducing the sulfur content of coal prior to combustion, by reacting the SO_2 with a reagent (typically calcium-based) either during or after combustion, or by a combination of both approaches. Postcombustion removal of SO_2 using wet or dry FGD (flue gas desulfurization) systems is the most common technology for conventional power plants. For PFBC systems, the SO_2 reacts with a sorbent injected directly into the fluid bed. This approach is also being examined as an option for IGCC systems employing fluidized-bed gasifiers. Gasification-based power systems convert sulfur to hydrogen sulfide (H_2S) rather than SO_2 . Current IGCC systems employ cold gas cleanup to remove H_2S via commercial low-temperature absorption systems. Advanced IGCC systems are being designed to remove H_2S using an absorption-regeneration system at high temperatures to improve system efficiency. Any H_2S remaining in the gas stream is oxidized to produce SO_2 emissions when the fuel gas is burned to generate electricity.

Nitrogen oxide emissions are formed from high-temperature reactions involving the oxygen and nitrogen present in coal and combustion air. Formation of NO_x can be reduced by various measures that control the temperature-time profile of combustion reactions. Postcombustion control of NO_x is typically accomplished by the injection of ammonia-based substances, with or without catalysts, that reduce NO_x to nitrogen gas. In gasification-based systems, nitrogen in the fuel gas stream typically occurs as ammonia, which is converted to NO_x upon combustion in the gas turbine. Cold gas cleanup systems remove most of the ammonia prior to combustion, thus lowering potential NO_x emissions, while current hot gas systems do not. In the latter case, postcombustion controls could be required to meet applicable emissions standards.

Most current methods of air pollution control generate some type of solid waste that must be disposed of or reused. At a minimum, the wastes include the mineral matter (ash) originally found in the coal. Other wastes arise from technologies to control SO_2 emissions. Technologies and processes do exist to replace or eliminate many of these wastes through reuse or by-product production, but most of these options are not economical in the United States at the present time. Hence, their use is not widespread. In the future, however, waste minimization is expected to become increasingly important in response to new economic and environmental pressures.

State of the Art

Recent trends in particulate, SO₂, and NO_x emission reductions achievable with current technology for pulverized coal-fired power plants were addressed in Chapter 3 (see Figure 3-2). Particulate control technologies were the first to be developed, and their evolution has been undertaken primarily by the private sector with limited government support. Current ESPs and fabric filters achieve emission levels of one-third to one-sixth NSPS levels at costs of about \$50 to \$75/kW and about 2 to 4 mills/kWh in total electricity cost (Sloat et al., 1993).

FGD technologies came into use in the United States in the 1970s and were developed throughout the 1980s with limited research and pilot plant efforts by EPA and DOE. Wet limestone systems, the most prevalent now in use, are being designed today for up to 95 percent annual average SO₂ removal, with about 97 to 98 percent removal using organic acid additives, in contrast to 90 percent removal a decade ago. Wet scrubbers using magnesium-enhanced lime systems are the most efficient FGD units now deployed, achieving over 98 percent SO₂ removal (Makansi, 1993a). For the typical plant shown earlier in Figure 3-2a, this corresponds to an emission rate of 0.1 lb SO₂/million Btu, or one-sixth the NSPS level. On low-sulfur coals, lime spray dryer systems, originally deployed as a 70 percent removal technology, today are designed for over 90 percent SO₂ removal in the United States and over 95 percent in Europe.

The cost of FGD systems also has decreased significantly as a result of process improvements and design simplifications over the past decade. Typical capital costs for application with a new power plant now range from about \$100 to \$200/kW, with total levelized costs of about 5 to 10 mills/kWh (Keeth et al., 1991). Capital costs for retrofit systems are typically higher than those cited above. For example, the capital cost of most FGD systems announced for Phase I compliance with the 1990 CAAAs (Clean Air Act amendments) range from \$220 to \$260/kW (Colley et al., 1993).

For NO_x control, advanced low-NO_x burner designs and other combustion modifications now available or nearing commercialization are able to achieve emission reductions of 30 percent or more below the NSPS level for new PC-fired power plants (Kokkinis et al., 1992). Costs are relatively low, at roughly \$7 to \$15/kW (EPRI, 1993b). Retrofit situations pose greater difficulties for coal plants due to the wide variety of boiler types and plant vintage. To date, NO_x reductions from existing coal-fired units have not yet been widely undertaken or required to meet the ambient NO_x standard.

Postcombustion NO_x removal systems employing selective catalytic reduction (SCR) technology are now in widespread use on coal plants in Japan and Germany, with about 30 GW of installed capacity (Scharer and Haug, 1993). Current SCR technology achieves up to 90 percent NO_x removal in low- and medium-sulfur coal applications overseas (Makansi, 1993b). Such systems have not yet been deployed in the United States, although demonstration of SCR with U.S. coals currently is in progress as part of DOE's CCT program. A commercial order also has been placed for SCR on a 285-MW coal-fired plant operated by an independent power producer (Makansi, 1993b).

The cost of SCR remains high relative to combustion controls, although a decade of experience and the emergence of industry competition have lowered the cost significantly. Capital costs today are roughly \$50 to \$80/kW, with total levelized costs of about 2 to 6 mills per kilowatt-hour for hot-side systems on new coal-fired plants (EPRI, 1991c). SCR costs are

dominated by the cost of the catalyst and frequency of catalyst replacement. Substantial cost reductions have been achieved in both areas in recent years. Retrofit costs for SCR can be significantly higher depending on the level of difficulty, the size and age of the plant, and other factors. For gas turbine systems, SCR already is required on some U.S. plants to meet local air quality standards. NO_x emission levels of 9 ppm or less are being achieved (Makansi, 1993b). Gas turbine designers also are employing a variety of combustion-based control measures in efforts to avoid the need for tail-end SCR.

The DOE CCT program has resulted in significant joint federal and private sector funding for the further development and demonstration of advanced emission control technologies. As elaborated in Chapter 8, this program includes the commercial demonstration of 19 emission control systems, with five completed, 11 in operation, and three in design and construction. Table 7-8 shows the control levels projected to be achieved by the emission control systems in the CCT program and indicates whether the technologies can be utilized for new facilities or as retrofits on an existing facility.

In addition to the emission control systems above, advanced systems employing hot gas cleanup and in-bed desulfurization are being developed. For PFBC systems, the current state of the art for sulfur removal employs a circulating PFBC designed to achieve SO₂ removal efficiencies of 95 percent or more (DOE, 1994a). Scale-up and demonstration of this capability are planned under Round V of the CCT program. The goal is to achieve SO₂ reductions comparable to modern FGD systems at reagent stoichiometries low enough to permit economical operation with minimum solid waste. At the present time, relatively high reagent use often is required to achieve high SO₂ removal efficiencies. The spent and unreacted sorbent roughly doubles the total solid waste for coal-fired plants.

Hot gas desulfurization systems that achieve over 99 percent sulfur removal from gasifier fuel gas streams also are scheduled for demonstrations in conjunction with several IGCC CCT projects. To date, hot gas (480 °C to 700 °C [900 °F to 1300 °F]) desulfurization systems employing regenerable metal oxides such as zinc ferrite and zinc titanate have not achieved the durability required for a cost-effective process. Continued work on improved sorbents and reactor designs is in progress (DOE, 1994b). System studies for IGCC systems using advanced fluidized-bed gasifiers also suggest that the optimal SO₂ removal system may be a combination of hot gas desulfurization and in-bed desulfurization in the gasifier using limestone.

Hot gas particulate removal from PFBC and IGCC gas systems also is under development. These devices can be viewed as an integral component of the power generation system rather than as an environmental control technology, since they serve the critical function of removing particles and alkaline materials from the fuel gas to protect the gas turbine from erosion and corrosion. For current and advanced turbine designs, the cleanup requirements needed to protect the turbine from particle-induced damage exceed the current requirements for environmental protection. The most promising systems to date have employed barrier filters designed to achieve emissions of less than 2 ppm by weight of particles greater than 5 microns in diameter. The major problem, however, has been longevity. Current candle filter designs have operated no more than several hundred hours at the required temperatures (760 °C to 870 °C [1400 °F to 1600 °F]) before breaking, whereas lifetimes on the order of 16,000 hours are needed for economical PFBC systems (DOE, 1994c). Improved designs, as well as testing in the

reducing gas environment of IGCC systems, are planned as part of the CCT demonstration projects.

With respect to solid waste emissions, many state-of-the-art air pollution control systems offer improved prospects for waste reduction through the production of salable by-products, especially with regard to sulfur emissions control. Modern FGD systems produce gypsum, which can be upgraded to commercial quality and sold (which is common practice in Europe and Japan). Several advanced flue gas cleanup systems being demonstrated in the CCT program produce by-product sulfur or sulfuric acid, as do the hot and cold gas cleanup systems employed with coal gasifiers. Only advanced PFBC systems increase rather than decrease the total solid wastes generated from coal use. In all cases the economic viability of by-product recovery systems depends on site-specific factors and markets. In the United States today, waste disposal in landfills is still more attractive for many electric utilities.

Technical Issues, Risks, and Opportunities

Existing control technologies for the criteria air pollutants (SO_2 , NO_x , and particulates) associated with PC-fired power plants are capable of meeting current or anticipated emission reduction requirements in the near term (i.e., prior to 2005). The same is true of cold gas cleanup control technologies for gasification-based systems. Cost reduction and minimization of solid waste remain important goals to improve the viability of these coal-based systems. For the medium term (post-2005), additional performance improvements also may be required, especially for NO_x controls.

Control technologies applicable to advanced combustion and gasification technologies need further development. In particular, hot gas cleanup systems for SO_2 and particulate removal, which are critical to several of the advanced high-efficiency technologies—especially PFBC—have yet to achieve the performance, reliability, or durability needed for commercial applications. In IGCC systems, hot gas cleanup does not presently control nitrogen emissions (in the form of gaseous ammonia), which increases downstream costs and complexity for NO_x controls in the gas turbine/heat recovery system. Research to address these issues is in progress.

With respect to solid waste minimization, one of the key needs is to improve the sorbent utilization for sulfur removal in advanced fluidized-bed combustors and gasifiers. Current PFBC systems produce the largest volume of solid waste per unit of sulfur removed. The presence of unreacted lime (as well as sulfides in the case of gasifiers) adds to the difficulty and cost of waste disposal. Pilot plant data for circulating PFBC designs show improved sorbent utilization relative to bubbling bed designs, but more work is needed to achieve commercially acceptable systems. More intensive research on reuse of spent sorbent also is needed if DOE's goal for solid waste reduction is to be achieved.

Control technologies for noncriteria pollutants also need to be addressed. To deal with the emerging issue of air toxics (see Chapter 3), trace substance emissions and fate must be characterized for current and advanced technologies. It is anticipated that existing high-efficiency particulate control technologies will be adequate to deal with most heavy metal emissions from coal combustion, but specific regulations have yet to be established. Similarly, the extent to which vapor-phase emissions such as mercury, chlorides, and selenium will have to be controlled

is not yet clear; technologies to control these emissions may well be needed in the near future. Should that be the case, an additional risk of hot gas cleanup systems is their uncertain capability to control emissions of air toxics, since they presently do not remove vapor-phase species. Additional controls for air toxics may impose additional economic costs.

The ability of control technology to reduce or eliminate emissions of potential air toxics is currently under study by DOE, EPRI, and others. The most prevalent data are for conventional cold-side ESPs, which show high removal efficiencies for most heavy metals but much lower removal rates for volatile species such as mercury (Rubin et al., 1993). Wet FGD systems in conjunction with an upstream particulate collector appear to offer the greatest removal rates of volatile species and other potential air toxics such as chlorides. However, there is large uncertainty in the data, with relatively little information currently available for wet scrubbers operating in the United States. Experiments with carbon-based additives show an enhanced ability to remove mercury in some cases, particularly with high chloride coals. Research on novel control methods for air toxics is being pursued by EPRI, DOE, and others.

As noted in Chapter 3, a major concern for all coal-based technologies is the potential requirement to control carbon dioxide (CO₂) emissions. The most economical means is to improve the efficiency of energy conversion and utilization so that less CO₂ is emitted per unit of useful energy delivered. For coal-fired power plants, average U.S. energy losses are about 2 percent in coal preparation, 67 percent in power generation, and 8 percent in transmission and distribution (EIA, 1993), yielding an overall efficiency of about 30 percent for fuel to delivered electricity. Within the limits of thermodynamic cycles, the greatest opportunity for energy efficiency improvements thus lies in the power generation process. As noted previously, the most efficient PC-fired plants commercially available today have efficiencies in the range of 38 to 42 percent. Thus, advanced technologies achieving 50 to 60 percent efficiency offer the potential to reduce CO₂ emissions up to a third relative to current new plants.

The potential for CO₂ capture and disposal also has received preliminary study (Ormerod et al., 1993; MIT, 1993; EPRI, 1991a). The consensus is that the technological means of scrubbing CO₂ from flue gases already exists today but that the feasibility of CO₂ disposal in deep wells, oceans, or other final storage sites remains a critical issue to be resolved. From a cost viewpoint, CO₂ removal today is very expensive. Estimates for a 90 percent CO₂ reduction suggest roughly a doubling of electricity generation costs and about a 35 percent energy penalty for removing and transporting CO₂ to a hypothetical disposal site (NRC, 1992). Somewhat lower energy penalties are estimated for advanced combustion and gasification cycles. The development of viable CO₂ removal and disposal processes remains a long-term challenge to control technology development.

Current DOE Programs

The Control Technology program in the Office of Fossil Energy is divided into four program components: Flue Gas Cleanup, Gas Stream Cleanup, Waste Management, and Advanced Research. As noted in Chapter 2, DOE has established incremental emission control goals for its Advanced Power Systems program (Table 2-3) that must be supported by the Control Technology program. The FY 1994 authorized budget for this activity was \$13.25

million for flue gas cleanup, \$19.29 million for gas stream cleanup, \$2.41 million for waste management, and \$1.16 million for advanced research.

As noted previously, commercial technology developed by the private sector with DOE participation already can achieve the DOE emission goals for 2000 and 2005 for conventional coal combustion systems. With the anticipated increase in demand for baseload generating capacity beyond 2005 and the expected tightening of future emission control requirements, the DOE program emphasis on developing improved control technologies for highly efficient, "superclean" power systems appears to be well placed.

The Flue Gas Cleanup program has a goal of reducing SO₂, NO_x, and particulate emissions to one-tenth current NSPS levels without high-volume waste generation (DOE, 1993a). Further goals are to control air toxics and CO₂ emissions and to develop salable by-products from the control systems. Development of advanced FGD systems and combined SO₂/NO_x removal systems is also part of this program area. The other major component is the Gas Stream Cleanup program. It has a similar focus of removing contaminants from gasifier or combustor streams prior to their entry into advanced power systems such as the PFBC, IGCC, and IGFC systems. Activities focus on the development of high-temperature, pressurized contaminant control systems.

DOE also has a Waste Management program focused on waste products formed by advanced power generation technologies. The goal of that program is to ensure that solid waste from advanced fossil energy technologies is not a roadblock to commercialization of those technologies. More specifically, the objectives are to achieve a 50 percent utilization of solid waste from advanced fossil energy technologies and commercial markets by 2010, to establish use for mine remediation of alkaline by-products such as are produced by fluidized-bed combustors and gasifiers with limestone added for sulfur removal, and to provide commercial acceptance of products manufactured from advanced pulverized coal by-products (DOE, 1993a). Many examples of successful waste product recycling, such as the use of flyash, exist. The best uses for the future are generally considered to be in construction, agriculture, mine reclamation, and soil stabilization. The present cost of these options and the enormous quantities of waste relative to by-product demand are the principal roadblocks to increased commercialization.

The final component of the Control Technologies Program is Advanced Research. The emphasis in this part of the program is on fundamental hot gas cleanup methods such as ceramic filter and membrane research.

Findings

Current commercial technologies for SO₂, NO_x, and particulate control for pulverized coal plants have improved substantially over the past decade and now can meet or exceed DOE's air pollutant emission targets for 2000 and 2005. Cost reduction is the primary need and the main potential benefit of current CCT demonstration projects.

The most difficult near-term R&D challenges are in development of the hot gas particulate and sulfur cleanup systems to be employed with advanced power generation systems (IGCC, PFBC, IGFC). In particular, the technical problems of achieving reliable and sustained operation have yet to be overcome. Solutions to these problems are central to the achievement

of cost-effective, high-efficiency power generation systems. Especially critical is the need for a high-temperature, high-pressure particulate removal system for advanced PFBC.

Other DOE programs are beginning or continuing to address the emerging issues of hazardous air pollutants (air toxics), greenhouse gas emissions (especially CO₂), and solid waste minimization. All of these are important issues that will require increased R&D attention in the future.

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Table 7-1 DOE's Program Goals for Pulverized Coal Systems

Technology Goals	Advanced Pulverized Coal		Indirectly Fired Cycle: Externally Fired Combined-Cycle/ High-Performance Power System		Direct Coal-Fired Heat Engines	
	Low Emission Boiler System	Coal-Fired Cogeneration	Coal-Fired Cogeneration	High-Performance Power System	Direct Coal-Fired Gas Turbines	Direct Coal-Fired Diesels
Net efficiency, percent	42	70 (total system)	70 (total system)	50	40	45
Emissions, fraction of SO ₂	1/3	Meet local regulations	Meet local regulations	1/10	Meet	Meet
New Source Performance Standards (NSPS)	1/3	Meet local regulations	Meet local regulations	1/10	Meet	Meet
Particulates	1/2	Meet	Meet	1/4	Not specified	Not specified
Air toxics emissions relative to 1990 Clean Air Act amendments	Meet	Meet	Meet	Meet	Meet	Meet
Solid wastes	Saleable	Benign	Benign	Benign/saleable	Not specified	Not specified
Capital cost, \$/kW	1,400	NA	NA	1,200	1,400	1,300
Electricity cost compared to current pulverized coal	Lower	NA	NA	10 percent lower	Lower	Lower
Commercial completion milestones	Commercial demonstration by 2000	5 MW demonstration in 2001	5 MW demonstration in 2001	Externally fired combined-cycle demonstration—1997; high-performance power system demonstration—2003	Proof of concept supporting projects complete in 1994	1.8-MW proof-of-concept demonstration in 1994
Development status	Preliminary commercial design in 1994	System design completed in 1994	System design completed in 1994	Development and testing of ceramic heat exchanger ongoing	Complete in 1993	Complete in 1993

NA, not available.
Source: DOE (1993a).

Table 7-2 DOE's Program Goals for Pressurized Fluidized Bed Combustion Systems

Pressurized Fluidized Bed Combustion			
Technology Goals	First-Generation	Second-Generation	Improved Second-Generation
Net efficiency, percent	40	45	≥50
Emissions, fraction of NSPS			
SO ₂	1/4	1/5	1/10
NO _x	1/3	1/5	1/10
Particulates	Not specified	Not specified	Not specified
Air toxics emissions relative to 1990 Clean Air Act amendments	Meet	Meet	Meet
Solid wastes	Not specified	Not specified	Not specified
Capital cost, \$/kW	1,300	1,100	1,000
Electricity cost compared to current pulverized coal	10 Percent lower	20 Percent lower	25 Percent lower
Commercial completion milestones	Commercial-scale demonstrations—mid-1990s	Commercial scale demonstration—2000	Commercial-scale demonstration—2007
Development status	70- to 80-MW demonstration projects ongoing	Systems development, integration, and testing ongoing	Development initiated

Source: DOE (1993a).

Table 7-3 IGCC Power Plant Performance and Economics Based on Shell Gasification Technology and Eastern Bituminous Coal (all costs in constant 1992 dollars)

Plant Parameter	Value
Nominal size, MW	500
Thermal efficiency (HHV basis)	
% Fuel to power	42
Net heat rate, Btu/kWh	8,900
Total capital cost, \$/kW	1,613
Levelized cost of electricity, ^a mills/kWh	41

^aAssuming a capacity factor of 80 percent and a levelized coal price of \$1.30/10⁶ Btu.
Source: EPRI (1993a).

Table 7-4 DOE's Program Goals for Integrated Gasification-Based Systems

Technology Goals	Second-Generation Integrated Gasification Combined-Cycle ^a	Integrated Gasification Advanced-Cycle	Integrated Gasification Fuel Cell
Net efficiency, percent	45 (by 2000)	≥50 (by 2010)	≥60 (by 2010)
Emissions, fraction of NSPS			
SO ₂	1/10	1/10	1/10
NO _x	1/10	1/10	1/10
Particulates	Not specified	Not specified	Not specified
Air toxics emissions relative to 1990 Clean Air Act amendments	Meet	Meet	Meet
Solid wastes	Not specified	Not specified	Not specified
Capital cost, \$/kW	1,200	1,050	1,100
Electricity cost compared to current pulverized coal	20 Percent lower	25 Percent lower	20 Percent lower
Commercial completion milestones	Demonstration 2001	Demonstration 2004	Coal demonstration 2000
Development status	Under development	Development initiated	Current activities focusing on natural gas-fired systems

^aFirst-generation integrated gasification combined-cycle power systems are presently at the commercialization stage and are being demonstrated with design improvements in the CCT program.

Source: DOE (1993a).

Table 7-5 Major European IGCC Projects in Progress

Project	Technology	Efficiency (percent)	MW (net)	Startup
SEP, Buggenum, Netherlands	Shell entrained Oxygen-blown Cold gas cleanup Siemens V94.2 gas turbine	41	253	January 1994
ELCOGAS, Puertollano, Spain	PRENFLO entrained Oxygen-blown Cold gas cleanup Siemens V94.3 gas turbine	43	300	Mid-1996
RWE, KoBra, Hurth, Germany	HT Winkler fluid bed Air-blown Cold gas cleanup Siemens V94.3 gas turbine	43	312	Post-2000

Source: Wolk and Holt (1994).

Table 7-6 Integrated Gasification Fuel Cell System Characteristics

Parameter	Phosphoric Acid Fuel Cell	Molten Carbonate Fuel Cell	Solid Oxide Fuel Cell
Design plant size (MW)	150	440	300
System efficiency on coal (% HHV)	33.5	51.3	46.6
NO _x , SO _x , VOCs ^a total (lb/MWh)	<1	<1	<1
Total capital cost (1992 \$/kW)	2,210	1,896	2,107
Year of commercial demonstration on natural gas	1993	1998	1998

^aVolatile organic compounds.

Sources: EPRI (1983, 1992a, 1993b).

Table 7-7 Characteristics of Natural-Gas-Fired Heavy-Frame, and Aero-derivative Combustion Turbine Power Plants

Turbine-Type	Simple-Cycle	Combined-Cycle
Heavy-frame	140-160 MW 34% efficiency	200-250 MW 50% efficiency
Aero-derivative	25-45 MW 36% efficiency	35-55 MW 47% efficiency

Source: Preston (1992).

Table 7-8 Combustion-Related Emission Control Systems in the Clean Coal Technology Program

Project	Removal Efficiency (percent)		Applicability	
	SO ₂	NO _x	New	Retrofit
<u>Sulfur Dioxide Removal</u>				
Gas suspension absorption	90+		X	X
Confined zone dispersion	50			X
Furnace sorbent injection with humidification (LIFAC)	85		X	
Advanced flue gas desulfurization	95+		X	X
CT-121 flue gas desulfurization system	98+		X	X
<u>NO_x Removal</u>				
Cyclone fired coal reburn		55		X
Low-NO _x cell burner		50+		X
Low-NO _x burner-gas reburn		70	X	X
Advanced combustion-wall fired		50	X	X
Advanced combustion-tangentially fired		48	X	X
Selective catalytic reduction		80	X	X
Micronized coal reburn		60	X	X
<u>Combined SO₂/NO_x</u>				
SNO _x catalytic advanced flue gas cleanup	96	94	X	X
Limestone injection multistage burner	70	50		X
SNRB combined SO _x and NO _x control	85	90	X	X
Low-NO _x burners & gas reburn	50	70		X
NO _x SO dry regenerable flue gas cleanup	97	70	X	X
S-H-U ^a wet FGD	95	30	X	X
Dry NO _x /SO ₂	70+	80+	X	X

^a Saarberg Holter Umwelt.
Source: DOE (1994a).