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**High Efficiency Integrated Environmental  
Control for Coal-Based  
Power Generation**

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## INTRODUCTION

The acid rain provisions of the 1990 Clean Air Act Amendments (CAAA) provide new incentives for the development of power generation technology with low SO<sub>2</sub> emissions. Detailed evaluations of possible NO<sub>x</sub> and air toxics emission limits also are required by the CAAA in the next few years. Furthermore, reauthorization of other key environmental legislation, such as the Clean Water Act and RCRA, will be considered by Congress in the 1990s. Thus, an increasingly multi-pollutant and multi-media approach to waste minimization will be required. If coal is to continue to supply the major electricity needs for the U.S., there is a need for new coal-based power generation technologies that can comfortably comply with both current and possible future environmental regulations.

Integrated gasification combined cycle (IGCC) systems are among the leading candidates to meet the environmental challenges of coal use. These modular systems can be configured in a number of ways to meet different goals with respect to plant performance (e.g., efficiency), emissions, and cost. IGCC systems are capable of stringent SO<sub>2</sub> control, and can simultaneously achieve low discharges of other key pollutants, such as NO<sub>x</sub>, particulates, and liquid and solid wastes.

This paper will discuss the performance and cost of a few alternative IGCC systems, with particular focus on SO<sub>2</sub> emissions. The paper also will consider how IGCC technology can respond to constraints on emissions of other pollutants. The state of development of IGCC systems, and the corresponding uncertainties in performance, emissions, and cost, also will be addressed.

## MOTIVATIONS FOR HIGH EFFICIENCY CONTROL

Current U.S. Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) applicable to coal-fired power plants require up to 90 percent sulfur dioxide (SO<sub>2</sub>) removal, over 99 percent particulate matter (PM) removal, and moderate (about 50 percent) reduction of nitrogen oxides (NO<sub>x</sub>) emissions. A conventional emission control system for a new pulverized coal (PC) power plant typically consists of a wet limestone flue gas desulfurization (FGD) system for SO<sub>2</sub> control, an electrostatic precipitator (ESP) for PM removal, and combustion controls for NO<sub>x</sub> reduction. These systems are all commercially available and well-demonstrated.

Advances in FGD technology, particularly involving the use of additives to enhance sulfur capture performance, promise to improve FGD operation and to allow SO<sub>2</sub> capture efficiencies significantly higher than 90 percent. Removal efficiencies on the order of 95 percent or higher may be achievable with only modest increases in capital and operating costs.<sup>1</sup>

High removal efficiency for NO<sub>x</sub> is also technically feasible. For example, recent commercial experience in Japan and Germany with selective catalytic reduction (SCR) indicates that 80 to 90 percent NO<sub>x</sub> removal may be feasible, although SCR has not yet been applied with U.S. coals.<sup>2</sup> For some types of coal-fueled power plant systems which are not yet commercialized, such as integrated gasification combined cycle (IGCC) systems, SCR is also an option for NO<sub>x</sub> control.

New plants may also be subject to permitting under Prevention of Significant Deterioration (PSD) rules, which are intended to preserve air quality based on ambient atmospheric concentration standards. Such permits are issued on a case-by-case basis and are often more stringent than NSPS.

Conventional electric power plants also are required to comply with EPA Effluent Guidelines and Standards for liquid discharges, including wastewater, cooling tower blowdown, boiler blowdown, ash transport water, process condensate, and purge water.<sup>3</sup> However, in many cases, a more stringent permit may be issued on a case-by-case basis under the National Pollutant Discharge Elimination System (NPDES).<sup>4</sup> Typically, water treatment systems are required in order to comply with either of these standards. Solid wastes from coal-fueled power plants are regulated under the Resource Conservation and Recovery Act (RCRA). Power plant solid wastes are usually nonhazardous, and as such are disposed of in accordance with the nonhazardous material guidelines of RCRA. A more detailed discussion of environmental regulations applicable to coal-based electric power plants may be found in Rubin (1989).<sup>5</sup>

## Recent Changes in Environmental Regulations

The most recent imperative for high-efficiency SO<sub>2</sub> removal is the acid rain provision of the CAAA signed by the President on November 15, 1990. Prior to 1995, 110 of the largest SO<sub>2</sub>-emitting stations are targeted for specific emission reductions. By 2000, the CAAA requires a reduction in national SO<sub>2</sub> emissions by 10 million tons/year compared to 1980 levels. After 2000, a nationwide SO<sub>2</sub> emission cap of 8.9 million tons/year will be in effect. In addition, emissions from virtually all power plants larger than 75-MW will be required not to exceed 1.2 lb SO<sub>2</sub> per million BTU (lb/MMBtu) of coal consumed. In its full implementation, the CAAA is a market-based approach to emission control, unlike the "command and control" NSPS regulations now in effect. Under the market-based system, each emitter must possess an emission allowance for each ton of SO<sub>2</sub> emitted annually. In principle, emitters are free to buy, sell, and bank emission credits to meet their needs and to comply with the national emission cap at lowest cost.<sup>6</sup>

Under the CAAA, each emitter faces economic incentive to reduce emissions to the point where the marginal cost of pollution control equals the cost of an emission credit. Thus, technologies which can economically achieve high removal efficiencies can provide a direct financial benefit to the utility. Thus, the CAAA may promote more rapid innovation in clean coal technology.

## Future Implications of the CAAA

The CAAA calls for a 2 million ton/year reduction in national NO<sub>x</sub> emissions by 2000.<sup>7</sup> EPA is required to set command-and-control NO<sub>x</sub> standards for tangentially-fired and dry-bottom wall-fired boilers, as well as for other boilers specified in the amendment. EPA must also set new NSPS for other fossil-fueled units. Trading between SO<sub>2</sub> and NO<sub>x</sub> is not part of the current CAAA, but may be studied later for possible inclusion in a future amendment.<sup>6</sup>

The CAAA also calls for studies of the hazards to public health reasonably anticipated to occur from emissions of hazardous air pollutants from electric steam generating units after the imposition of other requirements of the Amendment. A total of 189 chemical species have been named in the CAAA provisions for air toxics. In the study report, due to Congress by November 15, 1993, EPA must also develop and describe alternate control strategies for hazardous emissions

that may warrant regulation. EPA must then regulate electric utilities under Title III of the CAAA if "appropriate and necessary" after considering the results of the study.<sup>8</sup> Thus, emission reductions for certain hazardous air pollutants may also be required, in addition to SO<sub>2</sub> and NO<sub>x</sub> emission reductions.

### INTEGRATED ENVIRONMENTAL CONTROL

With the prospect of increasingly stringent emission control has evolved the concept of integrated environmental control. The concept has several dimensions. One is to consider interactions among control methods for air, water, and solid waste emissions, so that reductions in one type of discharge do not unduly increase others. Another is the integrated use of pre-combustion, combustion, and post-combustion control methods (as distinct from one approach alone). A third dimension is the development of new processes for combined pollutant removal in lieu of separate processes for individual pollutants. Other process innovations not directly related to emission control may also affect emissions. Thus, integrated environmental control represents good design practice and provides opportunities to minimize costs for a given set of emission reduction requirements.<sup>9</sup>

Key objectives of emissions control research, embodied in the notion of integrated environmental control, have been system simplification and cost reduction. Examples of integrated concepts for pulverized coal-fired power plants include combining flue gas SO<sub>2</sub> and NO<sub>x</sub> removal in a single reactor vessel, and coupling the designs of the power plant and emission control systems. An example of an advanced SO<sub>2</sub>/NO<sub>x</sub> emission control system for a pulverized coal-fired power plant is described by Frey and Rubin.<sup>10</sup>

The U.S. Department of Energy (DOE), Electric Power Research Institute (EPRI), and others have supported development of more advanced alternatives for control of SO<sub>2</sub> and NO<sub>x</sub> emissions from coal-fueled power plants. One alternative, integrated gasification combined cycle (IGCC), represents a new approach for the clean and efficient use of coal in electric power generation.

As emission control requirements have increased, so has the cost of conventional PC power plants, while their thermal efficiency has decreased, due to power requirements for emission control systems.<sup>11</sup> Natural gas- and oil-fired systems based on gas turbine combined cycle technology have high efficiencies, but consume expensive premium fuels. In a combined cycle plant, fuel is burned in a gas turbine, and the hot exhaust gas is used to generate steam for a steam cycle. By substituting synthetic fuel gas derived from coal for natural gas or oil, a coal-fueled gas turbine combined cycle power plant results. By integrating the steam cycle with the coal gasifier, the overall thermal efficiency can be optimized. Potential advantages of IGCC over PC plants include higher thermal efficiency, a capability for high (over 95 percent) sulfur removal efficiency, lower NO<sub>x</sub> emissions, low particulate emissions, reduced solid waste due to byproduct recovery of elemental sulfur, reduced cooling water requirements (because gas turbines, rather than boiler/furnaces, generate a large portion of the power), reduced land requirements and a capability to burn coal, oil, or natural gas.<sup>4</sup>

Compared to PC power plants, the notion of integrated environmental control is extended further in IGCC processes. In IGCC systems, environmental control is required not just to meet environmental regulations, but also for proper plant operation. For example, pollutants such as

sulfur species and ash particles have deleterious effects on key components of IGCC systems, such as the gas turbine, and therefore must be controlled. In addition, the environmental control systems significantly affect the thermal cycle and, hence, plant efficiency.

### INTEGRATED GASIFICATION COMBINED-CYCLE SYSTEMS

A number of variations of IGCC power plant designs exist, based primarily on differences in the coal gasifier technology. Both oxygen and steam are necessary reactants in the coal gasification process, which produces a syngas containing carbon monoxide and hydrogen. Alternate gasifier designs may use either oxygen or air as the oxidant. The primary difference in gasifier design is the type of reactor bed in which the coal is gasified. The three generic types of gasifiers are moving-bed, fluidized-bed, and entrained-flow. In a moving bed gasifier, coal flows downward counter-current with the steam and oxidant, and the highest temperatures are reached toward the bottom of the reactor. A prominent example of this type of gasifier is the Lurgi design. In a fluidized bed reactor, such as the Kellogg-Rust-Westinghouse (KRW) gasifier, the coal is well-mixed with steam and oxidant, leading to a more uniform temperature distribution in the gasifier. In an entrained flow gasifier, such as the Texaco or Shell designs, the coal is gasified in a plug flow reactor in which the coal and reactants move co-currently through the reactor. The gasifier design affects the temperature of the fuel gas, composition of the fuel gas (e.g., methane content, ammonia content, presence of tars and oils), ability to handle certain coals (e.g., caking coals), ability to handle fines, and oxidant and steam requirements, among other factors.<sup>4</sup>

EPRI has sponsored a number of performance and cost evaluations of IGCC technologies, focused primarily on entrained-flow gasifiers. This is partly because gasifiers such as the Texaco, Shell, and Dow designs have more operating experience on the demonstration plant level than other many other technologies.<sup>4</sup> EPRI, in cooperation with others, has co-sponsored the Cool Water gasification program, the first IGCC demonstration plant, based on the Texaco technology. The Cool Water IGCC plant was in service for five years. Emissions of SO<sub>2</sub> and NO<sub>x</sub> were well below both NSPS and the more stringent local emission permit limits for Cool Water.<sup>12</sup>

#### Baseline Technologies with Cold Gas Cleanup

An oxygen-blown (oxygen used as the oxidant) KRW-based system may offer some advantages over a comparable Texaco-based system, including reduced oxygen consumption, a lower temperature and pressure gasifier, a syngas with a higher heating value, and fewer parasitic loads (due largely to reduced oxygen consumption). Initial comparisons of Texaco and KRW based systems indicate that the heat rates (efficiency), capital costs, and levelized costs for these systems are competitive, even though a larger capital cost contingency factor was used for the KRW cost estimate.<sup>13</sup> A schematic of an oxygen-blown KRW-based IGCC system is shown in Figure 1.

Lurgi gasification technology is the oldest of the technologies most commonly considered for IGCC systems. The Lurgi dry-ash coal gasification process was developed in the 1930s in Germany, and over 150 gasifiers have been installed internationally since, most notably nearly 90 gasifiers in South Africa. Because the Lurgi gasifier is a moving-bed design in which the coal flows countercurrently with the steam and oxidant, the temperature varies throughout the reactor. The exiting gas temperature is lower than for other gasifier designs, and the "cold gas efficiency" (percent of chemical energy in the coal contained in the syngas) is higher than for other gasifier

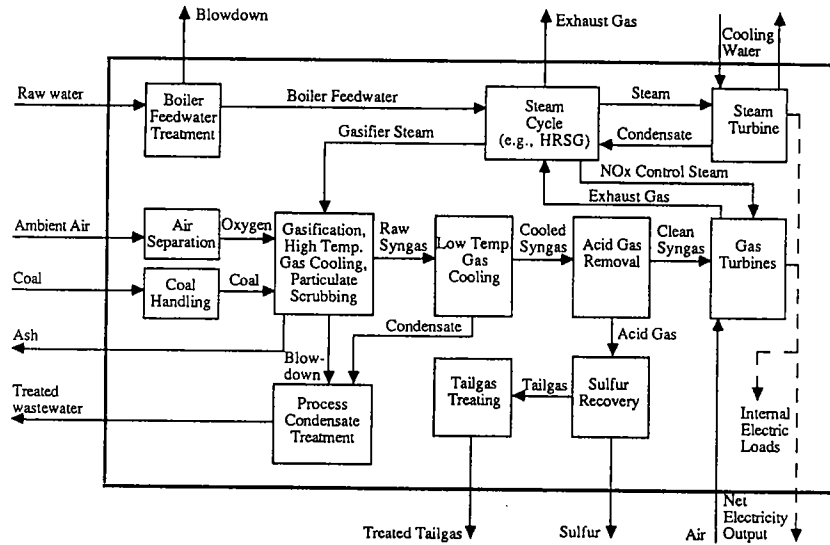


Figure 1. Schematic of oxygen-blown fluidized-bed KRW gasifier IGCC system with cold gas cleanup.

designs.<sup>4</sup> However, the syngas typically contains oils and tars, which must be removed from the syngas in conventional IGCC designs to avoid deposition on downstream equipment. The removal of tars and oils reduces the heating value of the syngas, and requires additional scrubbing equipment, increasing capital costs.<sup>14,15</sup> Alternatives to conventional gas cleanup systems may eliminate the requirement for syngas cooling in Lurgi-based systems, therefore preventing the condensation of tars and oils and eliminating the associated gas scrubbing equipment, resulting in significant cost savings.<sup>16</sup>

DOE's Morgantown Energy Technology Center (DOE/METC) has sponsored a number of system analysis studies to identify potentially promising advanced IGCC process configurations. These include simplified air-blown (air used as the oxidant) systems using Lurgi gasifiers and "hot" gas cleanup,<sup>16</sup> and the performance and cost of "hot" gas cleanup and sulfur recovery systems,<sup>17,18</sup> as opposed to the lower temperature "cold" gas sulfur removal systems assumed in EPRI studies. More recently, METC has sponsored a study by Southern Company Services of air-blown KRW-based IGCC systems featuring "hot" gas cleanup.<sup>19</sup>

Conventional IGCC designs, such as that of the Cool Water demonstration project, are based on "cold" gas cleanup, in which the fuel gas from the gasifier is cooled to a sufficiently low temperature (e.g., 100 °F) that the Selexol or similar sulfur removal process can be used to separate H<sub>2</sub>S from the fuel gas. A focus of research at the METC is the development of "hot" gas cleanup systems, in which sulfur compounds may be removed from the gasifier or the fuel gas at high temperature (e.g., 1,000 °F). Hot gas cleanup eliminates the capital cost associated with heat

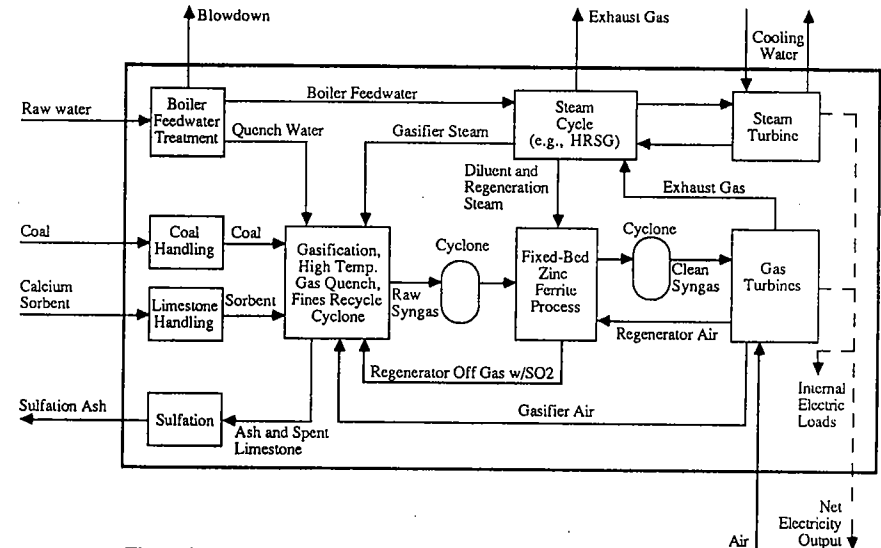


Figure 2. Schematic of air-blown fluidized-bed KRW gasifier IGCC system with hot gas cleanup.

exchangers needed to cool the fuel gas and process condensate treatment systems needed to handle condensate resulting from fuel gas cooling. Hot gas cleanup also reduces the thermal efficiency penalty associated with gas cooling, allowing the sensible heat of the high temperature fuel gas to be supplied directly to the gas turbine.

#### Advanced Systems with Hot Gas Cleanup

A promising hot gas cleanup configuration is an air-blown Kellogg-Rust-Westinghouse (KRW) IGCC system.<sup>19</sup> A schematic of this technology is shown in Figure 2. The hot gas cleanup system features in-bed desulfurization in the fluidized bed gasifier with limestone or dolomite, subsequent sulfur removal from the fuel gas with a zinc ferrite sorbent, and high efficiency cyclones and ceramic filters for particulate removal. The off-gas from the zinc ferrite reactor, which contains sulfur compounds, is recycled to the gasifier. The advantages of such a system, compared to a base case oxygen-blown system with cold gas cleanup, are: (1) it does not require an expensive and energy consuming oxygen plant, (2) it eliminates the capital costs associated with sulfur recovery (all sulfur is disposed with the spent limestone or dolomite), and (3) it reduces the amount of fuel gas cooling required prior to combustion in the gas turbine, thereby improving the plant thermal efficiency.

Testing of an air-blown KRW-based system with hot gas cleanup at the process development unit (PDU) level has been conducted.<sup>20</sup> M.W. Kellogg has presented some results of

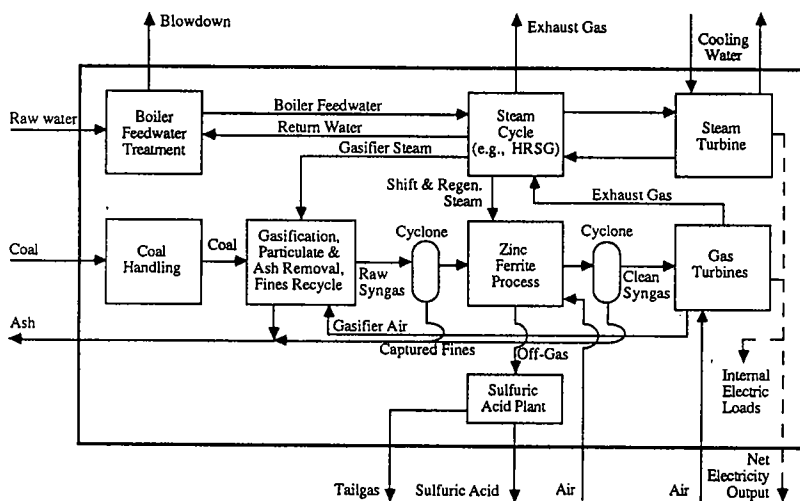


Figure 3. Schematic of air-blown dry-ash Lurgi gasifier IGCC system with hot gas cleanup.

a performance and cost analysis of such a system, although no detail was provided on costs.<sup>21</sup> M.W. Kellogg and Bechtel, under a cooperative agreement with DOE as part of the clean coal technology program, began design of a 63.5 MW demonstration plant of a KRW gasifier IGCC system with hot gas cleanup using the fixed-bed zinc ferrite process, although actual construction and testing has not occurred.<sup>20,22</sup>

In the fixed-bed zinc ferrite process, sulfur is removed from the syngas by reaction with a sorbent consisting of zinc ferrite pellets. Absorption occurs until just before "breakthrough", at which point the sorbent is saturated. The absorber is then taken off-line, and the syngas is diverted to another zinc ferrite reactor vessel containing regenerated sorbent. Sulfided sorbent is regenerated using air as a reactant and steam as a diluent, to prevent the heat released in the exothermic regeneration reactions from sintering the sorbent. The regeneration off-gas containing sulfur dioxide is then recycled to the gasifier, in KRW-based designs.

### Simplified IGCC

METC has also sponsored development of IGCC systems with hot gas cleanup based on the Lurgi gasification technology. A schematic of this technology is shown in Figure 3. The higher cold gas efficiency of Lurgi gasifiers compared to other gasifiers assumed for IGCC design can result in a higher plant efficiency, because a larger portion of the energy input enters the combined cycle system through the fuel gas rather than only through the steam cycle. The conversion efficiency of energy entering the gas turbine is much higher than that of energy entering the steam cycle. The exit temperature of syngas from a Lurgi or similar gasifier provides a more direct match with the temperature window of hot gas cleanup systems, thereby eliminating any

requirement for syngas cooling. Lurgi-based IGCC systems with hot gas cleanup therefore offer the potential for simplified plant designs. General Electric, under contract to METC, has been involved in analysis, testing, and development of hot gas cleanup systems for simplified Lurgi-based IGCC plants. These efforts include conceptual cost and design studies<sup>16,23</sup>, proof-of-concept system design studies<sup>24</sup>, and construction of a proof-of-concept system for a moving bed gasifier with hot gas cleanup.<sup>25</sup>

The focus of the General Electric research program is testing of a moving-bed zinc ferrite desulfurization system, in which sorbent circulates continuously between an absorber and regenerator vessel, as opposed to the fixed-bed system in which the sorbent remains in one vessel which is cycled between absorption and regeneration duty. The moving bed design offers advantages in terms of a steady flow of regeneration off-gases and the elimination of a requirement for steam as a diluent.<sup>24</sup> However, at this time, only limited design data and no detailed cost data are publicly available for this proprietary system.

### Technologies Evaluated in this Study

Based on a review of published design studies and research efforts, three IGCC technologies were selected for evaluation in this paper. These include one system featuring cold gas cleanup up, which is intended to be representative of conventional IGCC technology, and two advanced alternatives featuring hot gas cleanup, representing innovative process technologies. The advanced systems differ in the approach used for gasification and fuel gas desulfurization. These systems are:

- Oxygen-blown KRW-based IGCC with cold gas cleanup (Figure 1)
- Air-blown KRW-based IGCC with hot gas cleanup, featuring gasifier in-bed bulk desulfurization and external fuel gas polishing desulfurization using the fixed bed zinc ferrite process (Figure 2)
- Air-blown Lurgi-based IGCC with hot gas cleanup, featuring external fuel gas bulk desulfurization using the fixed bed zinc ferrite process (Figure 3)

### MODELING PERFORMANCE AND COST

The performance, emissions, and cost of each of the three IGCC systems selected for evaluation in this paper are modeled using detailed engineering models. For each of the three systems, performance models were developed by DOE/METC using the ASPEN chemical process simulator. These performance models have been significantly modified to more completely and accurately represent process performance and emissions. Furthermore, new cost models for all three systems were developed. The details of model development and applications are reported elsewhere.<sup>26-29</sup>

A unique aspect of the engineering modeling in this study is the use of probabilistic simulation techniques to explicitly represent uncertainties in these advanced technologies, which have not been commercially demonstrated. In many cases, model input assumptions are given probability distributions, rather than single numbers. These distributions are then propagated through the computer models using a variation of Monte Carlo simulation called Latin Hypercube sampling (LHS). LHS is a stratified sampling technique that is more efficient than random Monte

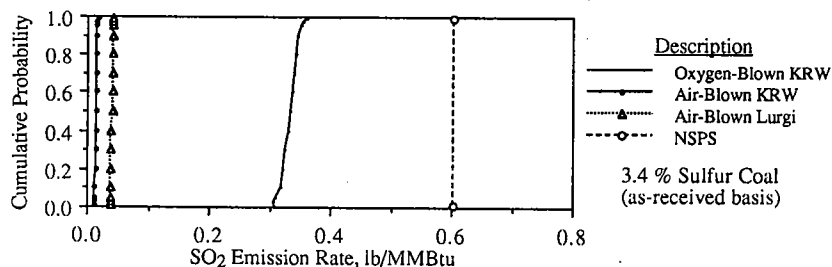


Figure 4. Uncertainty in SO<sub>2</sub> emission rates for three IGCC systems.

Carlo simulation. A new capability has been added to the ASPEN chemical process simulator by Rubin and Diwekar<sup>30</sup> for probabilistic simulation, based on work by Iman and Shortencarier.<sup>31</sup>

Key performance and cost parameters of the engineering models for each of the three IGCC systems were assigned probability distributions based on data analysis, literature review, or the elicitation of expert judgments. The input assumptions are documented by Frey.<sup>28</sup>

#### High Efficiency Sulfur Control

The approach to sulfur emissions control in an IGCC plant is fundamentally different from a pulverized coal-fired power plant. Emission control strategies typically focus on the fuel gas, which is pressurized (typically 300 to 500 psi) and has a substantially lower volumetric flow rate than the conventional flue gas, which flows near atmospheric pressure, of coal-combustion power plants. Furthermore, sulfur in the fuel gas is in reduced form (mostly H<sub>2</sub>S), which can be removed by a variety of commercially available processes.<sup>4</sup> Typically, H<sub>2</sub>S and COS are removed using a Selexol or similar process, and the concentrated acid gas is then processed for elemental sulfur recovery. In many recent design studies, the Selexol process is assumed to be capable of 98 to 99 percent of H<sub>2</sub>S, and approximately 30 percent of COS.

The simulated SO<sub>2</sub> emission rates for the three IGCC systems considered in this study are compared in Figure 4, based on a 3.4 percent Illinois No. 6 coal and other modeling assumptions documented by Frey.<sup>28</sup> For the oxygen-blown KRW system with cold gas cleanup, a fuel gas H<sub>2</sub>S capture efficiency of 95 percent and a COS capture efficiency of 31.7 percent are assumed. The resulting emission rate of SO<sub>2</sub> is well below current NSPS for coal-fired power plants, with a mean value of 0.34 lb/MMBtu and a 90 percent probability range from 0.31 to 0.35 lb/MMBtu. The uncertainty in this emission rate is due primarily to uncertainty in sulfur retention in the gasifier bottom ash, which ranges from 10 to 20 percent of the inlet sulfur in the coal. Additional reductions in emissions are possible at modest incremental cost.<sup>4</sup>

For the two air-blown systems with zinc ferrite desulfurization, the SO<sub>2</sub> emission rates are substantially lower. For the air-blown KRW system, in-bed desulfurization is expected to result in 90 percent sulfur capture within the gasifier. The external zinc ferrite desulfurization process is expected to reduce the sulfur content of the syngas to 10 ppmv, resulting in low SO<sub>2</sub> emissions from the gas turbine combustor. Upon regeneration, the sulfur captured by the zinc ferrite sorbent is evolved in an offgas containing SO<sub>2</sub>, which is recycled to the gasifier for capture by the calcium-

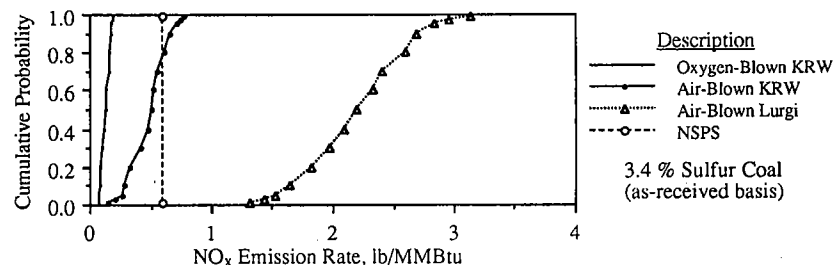


Figure 5. Uncertainty in NO<sub>x</sub> emission rates for three IGCC systems.

based sorbent. Thus, the SO<sub>2</sub> emissions from the air-blown KRW system are slightly lower than for the air-blown Lurgi system. Both systems have emissions significantly below 0.1 lb/MMBtu.

#### Control of Other Pollutants

Thermal NO<sub>x</sub> emissions are expected to be quite low for IGCC systems, due to the low heating value of the fuel gas. The presence of thermal diluents such as H<sub>2</sub>O, CO<sub>2</sub>, and N<sub>2</sub> result in relative low combustor flame temperatures and, hence, reduce the formation rate of NO<sub>x</sub>.<sup>32</sup> However, the hot gas cleanup systems employed by both the air-blown KRW and Lurgi systems do not remove fuel-bound nitrogen from the fuel gas, whereas the cold gas cleanup system removes ammonia (the key fuel-bound nitrogen species) via wet scrubbing. Thus, fuel-bound NO<sub>x</sub> emissions may pose a concern for air-blown systems.

As shown in Figure 5, the NO<sub>x</sub> emissions for the oxygen-blown system with cold gas cleanup are significantly less than the current NSPS for coal-fired power plants. However, for the air-blown KRW system, there is approximately a 20 percent probability of exceeding the NSPS value, and for the air-blown Lurgi system, which has a high ammonia concentration in the fuel gas, the uncontrolled fuel NO<sub>x</sub> emissions will exceed NSPS. The uncertainties in the NO<sub>x</sub> emission rates for these two systems are due to uncertainty in both the concentration of ammonia in the fuel gas and the conversion rate of ammonia to NO<sub>x</sub> in the gas turbine combustor.

Alternative NO<sub>x</sub> control technologies, such as rich/lean staged combustion and/or post-combustion selective catalytic reduction (SCR), are under consideration for future applications if fuel NO<sub>x</sub> emissions must be reduced more stringently. For example, an SCR removal efficiency of 80 percent will control the NO<sub>x</sub> emissions of the air-blown Lurgi system within the coal-fired NSPS.

A gaseous discharge of emerging concern is CO<sub>2</sub>. The CO<sub>2</sub> emissions of the three IGCC technologies are compared in Figure 6. In addition, the CO<sub>2</sub> emissions of a PC power plant with wet limestone FGD are shown for comparative purposes. The performance and cost of the PC/FGD system were simulated using the Integrated Environmental Control Model (IECM) developed by Rubin *et al.*<sup>33</sup>, based on assumptions documented by Frey and Rubin.<sup>10</sup>

Due to the significantly higher thermal efficiencies of the IGCC systems, the CO<sub>2</sub> emissions of the IGCC systems are approximately 15 percent lower than for the PC/FGD system. However, differences in gasifier bottom ash carbon retention, and the calcination of limestone

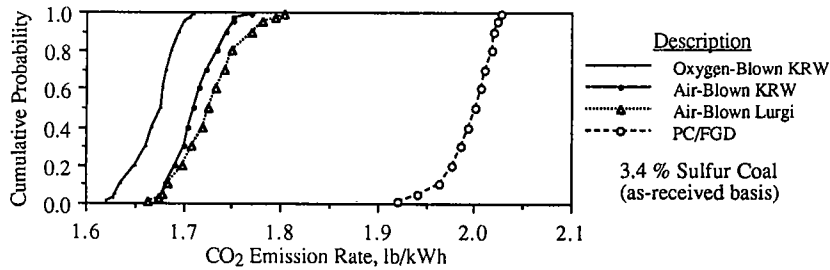


Figure 6. Uncertainty in CO<sub>2</sub> emission rates for four coal-based electric power systems.

sorbent in the air-blown KRW system, lead to variations in CO<sub>2</sub> emissions for the three IGCC systems. The mean efficiencies of the oxygen-blown KRW, air-blown KRW, air-blown Lurgi, and PC/FGD systems are 36.0, 41.0, 37.5, and 34.8 percent, respectively. Thus, the two most efficient IGCC systems are shown to have slightly higher CO<sub>2</sub> emissions than the oxygen-blown system.

The IGCC systems also enjoy advantages over the PC/FGD system in terms of ash disposal burden, as shown in Figure 7. Two of the IGCC systems, the oxygen-blown KRW and air-blown Lurgi, have ash disposal rates that are approximately 40 percent or less than that of a PC/FGD system, on a mass basis. For the oxygen-blown system, IGCC solid wastes include gasifier bottom ash and particulate cake from the scrubber system. These solid wastes are suitable for landfilling. Compared to a pulverized coal-fired plant with FGD, a portion of the solid waste burden from an IGCC system is eliminated by the production of a byproduct (e.g., sulfur or sulfuric acid) and the lack of a spent sorbent waste. However, this latter advantage is not applicable to the air-blown KRW system, which employs a limestone sorbent for in-bed desulfurization. Nonetheless, this system has approximately a 20 percent lower ash disposal rate than the PC/FGD system.

The IGCC systems with hot gas cleanup are not expected to have any liquid discharges other than those normally associated with the steam cycle and plant utilities. The solid waste streams include bottom ash (which includes spent limestone sorbent), fines collected in the

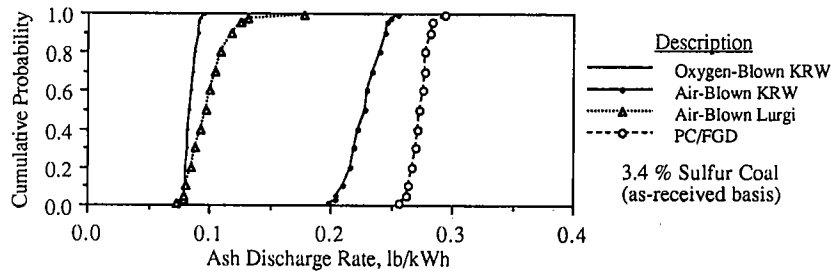


Figure 7. Uncertainty in ash discharge rate for four coal-based electric power systems.

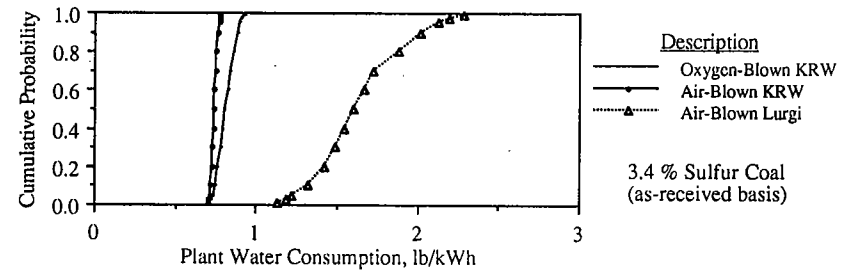


Figure 8. Uncertainty in plant water consumption for three IGCC systems.

secondary cyclones, and spent zinc ferrite sorbent. However, it is assumed that the spent zinc ferrite sorbent is returned to the manufacturer for reprocessing. In IGCC systems featuring fuel gas cooling, such as the oxygen-blown KRW system, liquid condensates from the high temperature fuel gas must be removed and treated prior to discharge. Additionally, blowdown from the fuel gas scrubber must also be treated. These wastewater streams are in addition to the steam cycle and cooling water cycle blowdown streams typical of modern thermal power stations.

The three IGCC systems also differ in terms of process water requirements. The lower temperature Lurgi gasifier requires significantly more water than the two KRW options, as shown in Figure 8.

### Process Economics

IGCC systems are becoming increasingly cost-competitive with PC-based power generation technologies. A comparison of the total levelized costs of the three IGCC technology operations and a baseline PC/FGD system is shown in Figure 9. The cost of the air-blown KRW system is shown to be within roughly 10 to 20 percent of the PC/FGD system. The air-blown Lurgi system also offers potential promising levelized costs; however, uncertainties in the performance and cost of the zinc ferrite desulfurization system lead to the possibility of very high operating costs. The oxygen-blown KRW system has the highest average cost, primarily due to the cost of air separation, gas cooling, process condensate treatment, and gas scrubbing systems.

IGCC systems are not yet commercialized. Several demonstration plants have been built, notably the Cool Water plant in California<sup>12</sup> and the Dow Chemical IGCC plant in Louisiana.<sup>34</sup> These systems employ cold gas cleanup, which we consider to be a "baseline" technology representing the lowest technical and economic risks for future IGCC systems. Hot gas cleanup systems have not yet been demonstrated at a commercial scale, although testing of process development unit (PDU) scale systems has been sponsored by DOE. The uncertainties in predicting commercial-scale performance and cost of systems with hot gas cleanup are reflected in the estimates given in Figure 9.

### DISCUSSION AND CONCLUSIONS

The comparison presented here between IGCC and PC/FGD systems indicates potentially overall superior environmental performance of IGCC systems with respect to air, water, and solid

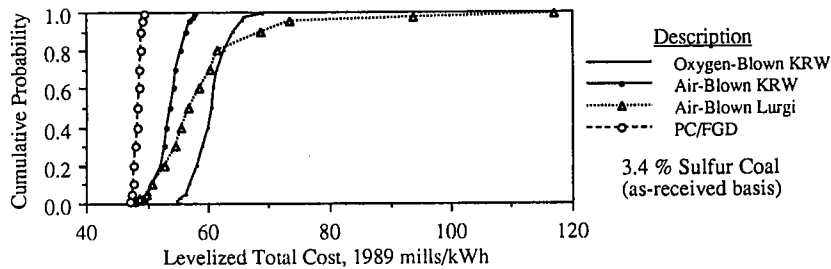


Figure 9. Uncertainty in total levelized costs for four coal-based electric power systems.

pollutants. With only modest increases in cost, and modest penalties on plant efficiency, SCR may be added to IGCC systems to further reduce NO<sub>x</sub> emissions.<sup>35</sup>

Among the three IGCC systems analyzed, the oxygen-blown IGCC system produced the lowest NO<sub>x</sub>, CO<sub>2</sub>, and ash discharges. It also has low water consumption comparable to that of the air-blown KRW system. The SO<sub>2</sub> emission rate can be lowered by changing the design (and increasing the cost) of the Selexol unit to achieve higher (e.g., over 99 percent) H<sub>2</sub>S removal efficiency.

The wet scrubbing cold gas cleanup system is more likely to remove air toxics from the fuel gas than the dry physical-chemical cleanup employed in the two air-blown systems. Thus, air toxic emissions may be more of a concern for IGCC systems employing hot gas cleanup technology. This area remains to be addressed in future studies.

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#### NOTE TO EDITORS

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