INTEGRATION OF COAL UTILIZATION AND
ENVIRONMENTAL CONTROL IN IGCC SYSTEMS

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ABSTRACT

Integrated gasification combined cycle (IGCC) systems are a new generation of coal-fueled
power generation technologies which embody the notion of integrated environmental control.
However, because few IGCC concepts have been demonstrated at a commercial scale, there is
significant uncertainty regarding the emissions, performance and cost of these systems in full-scale
applications. To capture the effect of such uncertainties in preliminary design studies, a
probabilistic approach to performance and cost modeling is employed, in contrast to conventional
deterministic (point-estimate) methods. Examples of IGCC system concepts involving both cold
and hot gas cleanup are evaluated probabilistically, to provide insights into the resulting differences
in plant performance, emissions, and cost.

INTRODUCTION

Integrated gasification combined cycle (IGCC) systems represent a promising new
approach for the clean and efficient use of coal for power generation, offering low levels of SO2
and NOx emissions along with benign solid wastes or byproducts, and zero or low wastewater
discharges. A distinguishing feature of IGCC concepts is the type of fuel gas cleanup strategy
employed. Typical designs for IGCC systems use "cold gas cleanup" (CGCU), including low
temperature removal of SO2 and particulates from the coal syngas, sulfur byproduct recovery, and
syngas moisturization to reduce NOx formation in the gas turbine combustor. On-going research
by the U.S. Department of Energy (DOE) and others is focused on developing alternative methods
for reducing SO2 emissions using dry physical and chemical hot gas cleanup (HGCU) techniques
to reduce the efficiency penalty associated with syngas cooling [1]. The cost and performance of
IGCC systems with hot gas cleanup is expected to compare favorably with advanced alternatives
for SO2 and NOx emission control in pulverized coal power plants.

The environmental control systems in IGCC plants significantly affect the thermal cycle
and, hence, plant efficiency. Furthermore, environmental control is required not just to meet
environmental regulations, but as an integral part needed for proper plant operation. In particular,
contaminants such as sulfur, particulates, and alkali must be removed prior to fuel gas combustion
to protect the gas turbine components from erosion, corrosion, and deposition. Because of the
close interactions among plant performance, environmental control, and cost, assessments of
IGCC technology must be based on integrated analysis of the entire system.

At the present time, however, there is still very limited experience with IGCC power
systems. The uncertain nature of the limited performance data for the first generation systems,
coupled with uncertainties associated with alternative process configurations, suggests a strong
need for systematic analysis of uncertainty in evaluating alternative designs and their environmental
performance. Furthermore, even if process performance is known with certainty, there is typically
uncertainty in the cost of equipment, maintenance, operation, consumables, byproduct credits, and
waste disposal. Failure to fully account for uncertainties in process performance and cost analyses
often results in misleading estimates for comparative analysis and planning, particularly for pioneer
process plants [2]. To explicitly represent uncertainties in IGCC systems, a probabilistic modeling approach has been developed. This approach features: (1) development of sufficiently detailed engineering models of performance, emissions, and cost; (2) implementation of the models in a probabilistic modeling environment; (3) development of quantitative representations of uncertainties in specific model parameters based on literature review, data analysis, and elicitation of technical judgments from experts; and (4) modeling applications for cost estimating, risk assessment, and research planning.

Using the probabilistic modeling approach, this paper will explore the close interactions among environmental control, plant performance, and cost in IGCC systems. The study will focus on the implications of alternative fuel gas treatment technologies with respect to: air, solid, and liquid discharges; plant efficiency; and plant cost. Results will illustrate the types of insights provided by a probabilistic method for evaluating IGCC system designs.

IGCC TECHNOLOGY

An example of an IGCC system concept with CGCU is shown in Figure 1. The design basis for this system, which features fluidized-bed gasifiers, is described by Dawkins et al. [3]. The fuel gas cleanup system is representative of the technology employed in the Cool Water demonstration plant [4]. Coal is partially combusted with oxygen and gasified with steam in a reducing atmosphere to yield a fuel gas containing CO and H₂ as key constituents. Oxygen for the gasifier is provided by an air separation plant. Steam is supplied from the plant steam cycle. The hot fuel gas is cooled in a steam generator, and then enters a low temperature cooling section. As part of low temperature cooling, nearly all of the the particulate matter and ammonia in the fuel gas is removed by wet scrubbing. The fuel gas, at a temperature of about 100 °F, then enters a Selexol acid gas removal unit, where H₂S, the primary sulfur species in the fuel gas, is selectively removed. The clean fuel gas is then combusted in a gas turbine combined cycle system. A portion of the electrical output from the generators must be used to power equipment in the plant, most notably the air separation plant.

Environmental Performance for Cold Gas Cleanup

The approach to 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. Furthermore, sulfur in the fuel gas is in reduced form (mostly H₂S), which can be removed by a variety of commercially available processes [5]. Typically, H₂S and COS are removed using a Selexol or similar process, and the concentrated acid gas is then processed for elemental sulfur recovery. Fuel gas cleanup is also necessary because particulate control and sulfur removal are required to meet gas turbine design specifications for fuel gas composition. Removal of ammonia in the fuel gas in wet scrubbing systems reduces substantially the amount of fuel-bound nitrogen in the fuel gas. In conventional gas turbine combustors, most of the fuel-bound nitrogen is converted to NOₓ. Thermal NOₓ emissions are controlled either by moisturization of the fuel gas or gas turbine combustor steam injection to reduce the flame temperature.

In the Cool Water demonstration plant, air emissions with low-sulfur coal were reported to be 0.06 lb NO₂/MMBtu, 0.07 lb SO₂/MMBtu, and 0.008 lb/MMBtu of particulate matter (PM) [4]. All three rates are well below federal New Source Performance Standard (NSPS) levels for conventional coal-fired power plants.

In IGCC systems featuring fuel gas cooling, liquid condensates from the high temperature fuel gas must be removed and treated prior to discharge. Additionally, blowdown from the fuel
Figure 1. Schematic of Oxygen-Blown Fluidized Bed Gasifier IGCC System with Cold Gas Cleanup
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.

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 an elemental sulfur byproduct and the lack of a spent sorbent waste.

**Hot Gas Cleanup**

Although conventional IGCC system designs with CGCU incorporate environmental controls as an integral part of the power plant, improved fuel gas cleanup systems have important implications for plant performance. So-called "hot gas cleanup" (HGCU) systems reduce or eliminate the need for syngas cooling prior to particulate removal and desulfurization. This improves the plant thermal efficiency and reduces or eliminates the need for heat exchangers and process condensate treatment. Thus, HGCU offers a more highly integrated system in which a major wastewater stream is eliminated.

An example of an air-blown fluidized-bed gasifier IGCC system with HGCU is shown in Figure 2. The schematic represents process elements based on design and cost studies prepared for GRI [6,7] and for DOE [8]. The primary features of this design, compared to the IGCC system with CGCU, are: (1) elimination of an oxygen plant by using air, instead of oxygen, as the gasifier oxidant; (2) in-situ gasifier desulfurization with limestone or dolomite; (3) external (e.g., not in the gasifier) desulfurization using a high temperature removal process; (4) high efficiency cyclones for particulate removal; (5) elimination of heat exchangers for fuel gas cooling at gasifier exit; (6) elimination of sulfur recovery and tail gas treating; and (7) addition of a circulating fluidized bed boiler for sulfation of spent limestone (to produce an environmentally acceptable waste) and conversion of carbon remaining in the gasifier ash. The design basis assumed here includes the use of water quench, rather than heat exchange, for high temperature syngas cooling from 1,850 °F at the gasifier outlet to 1,100 °F prior to gas cleanup. Therefore, there is no knockout drum for process condensate removal. The clean fuel gas is then combusted in a gas turbine modified to fire low-BTU coal gas.

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 SO₂ emissions from the gas turbine combustor. Upon regeneration, the sulfur captured by the zinc ferrite sorbent is evolved in an offgas containing SO₂, which is recycled to the gasifier for capture by the calcium-based sorbent.

Thermal NOₓ emissions are expected to be quite low for air-blown IGCC. However, the hot gas cleanup system shown in Figure 2 does not remove fuel-bound nitrogen from the fuel gas. Thus, fuel-bound NOₓ emissions may pose a concern. However, alternatives such as rich/lean staged combustion and/or post-combustion selective catalytic reduction are under consideration for future applications if fuel NOₓ emissions must be reduced more stringently.

The IGCC/HGCU system is 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 secondary cyclones, and spent zinc ferrite sorbent. However, it is assumed that the spent zinc ferrite sorbent is returned to the manufacturer for reprocessing.

**Commercial Status**

IGCC systems are not yet commercialized. Several demonstration plants have been built, notably the Cool Water plant in California and the Dow Chemical IGCC plant in Louisiana. These
Figure 2. Schematic of Air-Blown Fluidized Bed Gasifier IGCC System with Hot Gas Cleanup
systems employ CGCU, which is considered to be a "baseline" technology representing the lowest technical and economic risks for future IGCC systems. HGCU systems have not yet been demonstrated at a commercial scale, although testing of process development unit (PDU) scale systems has been sponsored by DOE. Thus, there is still considerable uncertainty in predicting the commercial-scale performance and cost of IGCC systems with HGCU.

IGCC SYSTEM PERFORMANCE AND COST MODELS

A number of IGCC performance models have been developed by DOE's Morgantown Energy Technology Center (DOE/METC) using ASPEN, a chemical process simulator [9,10]. One limitation of ASPEN has been the inability to analyze uncertainties. Typically, sensitivity analysis is employed in which only one or two parameters are varied at a time in a simulation containing hundreds of independent variables. Thus, important interactions or cases easily can be overlooked. Another limitation of the existing IGCC process models has been a lack of directly coupled cost models, which has prevented the simultaneous evaluation of process performance and economics in a single computer simulation. Work previously reported has addressed both of these limitations. To explicitly characterize uncertainties, a general probabilistic modeling capability has been developed and implemented in ASPEN [11]. To evaluate the economics of selected IGCC systems, new cost models, which estimate capital and annual costs, have been developed and directly coupled to ASPEN performance models previously developed by DOE/METC [12]. The cost models for each IGCC system are sensitive to approximately 100 performance, design, and economic parameters. The performance and cost models are modular. Process areas that are common to both IGCC systems are modeled consistently, permitting comparative analysis of the alternative technologies.

CHARACTERIZING UNCERTAINTIES

Nearly all analyses of energy and environmental control technologies that are still in the research phase involve uncertainties. In developing performance and cost estimates of technologies that are in early stages of development, the most common approach is for engineers to assume a "best guess" point-value judgment for key parameters. These judgments may be intended to represent neither undue optimism or pessimism regarding the technology, or they may be intended to incorporate a degree of conservatism. However, the basis for many assumptions, and the scope of thought that went into them, are often not explicitly documented in conceptual design studies. Thus, the degree of confidence that a decision-maker should place in the performance and cost estimate is often not rigorously considered.

The most common approach to handling uncertainties is either to ignore them or to use simple "sensitivity" analysis. In sensitivity analysis, the value of one or a few model input parameters are varied, usually from "low" to "high" values, and the effect on a model output parameter is observed. Meanwhile, all other model parameters are held at their "nominal " values. In practical problems with many input variables which may be uncertain, the combinatorial explosion of possible sensitivity scenarios (e.g., one variable "high", another "low," and so on) becomes unmanageable. Furthermore, sensitivity analysis provides no insight into the likelihood of obtaining any particular result.

A more robust approach is to represent uncertainties in model parameters using probability distributions. Using probabilistic simulation techniques, simultaneous uncertainties in any number of model input parameters can be propagated through a model to determine their combined effect on model outputs. The result of a probabilistic simulation includes both the possible range of values for model output parameters and information about the likelihood of obtaining various results. This provides insights into the risks or potential pay-offs of a new technology. Statistical analysis on the input and output data can be used to identify trends (e.g., key input uncertainties affecting output uncertainties), without need to re-run the analysis. Thus, probabilistic analysis
can be used as a research planning tool to identify the uncertainties in a process that matter the most, thereby focusing research efforts where they are most needed. Probabilistic analysis may be referred to elsewhere as "range estimating" or "risk assessment."

There are three general areas of uncertainty that should be explicitly reflected in engineering models. These are uncertainties in: (1) process performance parameters (e.g., flowrates), (2) process area capital costs, and (3) process operating costs. For example, in calculating the cost of a gasifier, there may be uncertainty (because of the lack of commercial experience with the design) in the coal throughput required to achieve a given fuel gas specification. This leads to uncertainty in the size and number (hence, cost) of gasifiers for a particular IGCC system. However, for a given gasifier size and type, there is also a probability that the equipment cost could be higher or lower than the nominal estimate (e.g., due to expected improvements in equipment design and cost, or to potential problems with fouling and corrosion, requiring more expensive materials, design modifications, or additional maintenance). The same type of uncertainties may apply to operating and maintenance cost factors. The uncertainties associated with advanced systems or subsystems will typically be much larger than for conventional technology. A probabilistic engineering modeling framework is required to evaluate the overall uncertainty in process cost, as a result of performance and cost uncertainties in specific process areas, to determine the overall technical and cost risks and to identify research priorities.

The development of ranges and probability distributions for model input parameters in the case studies reported here is based on information available in published studies, statistical data analysis and/or the judgments of process engineers with relevant expertise. The approaches to developing probability distributions for model parameters are similar in many ways to the approach one might take to pick a single "best guess" number for deterministic (point-estimate) analysis or to select a range of values to use in sensitivity analysis. However, the developmental of estimates of uncertainty usually requires more detailed thinking about possible outcomes and their relative likelihoods.

For the IGCC system with CGCU, uncertainties were assigned to 41 engineering model parameters. For the IGCC system with HGCU, 46 parameters were treated probabilistically. A few of these uncertainties are shown here as examples. The uncertainties assumed for the gasification process area of the systems with CGCU and HGCU are shown in Tables 1 and 2, respectively. Uncertainties were also ascribed to other process area performance parameters (e.g., gas turbine, sulfation, zinc ferrite), capital cost model parameters, process area direct cost estimates, maintenance cost factors, variable operating cost parameters (e.g., unit costs of consumables, waste disposal, and byproducts), and regression model error terms. Regression models are used to characterize the direct cost of several process areas as a function of key performance parameters, and to estimate auxiliary power requirements for some process areas. Complete details regarding the development of uncertainty estimates in the IGCC models are given by Frey [13].

RUNNING THE MODELS

The IGCC models were run on a DEC VAXStation 3200 mini-computer using the public U.S. Department of Energy version of ASPEN. Running an ASPEN flowsheet involves several steps. For a single run of an IGCC flowsheet, representing either a deterministic analysis or a single repetition during a stochastic analysis, the run time may take approximately 2 to 10 minutes, depending on the flowsheet, initial guesses for key variables, and limits specified in ASPEN design specifications (see MIT [10] for a description of the structure of ASPEN models). Thus, a deterministic analysis may take approximately 20 to 30 minutes to run, including input translation, compiling, linking, execution, and report generation. In the case of a probabilistic simulation, the flowsheet is executed many times, with a different set of values (samples) assigned to uncertain input parameters each time. Thus, a probabilistic analysis with a sample size of 100 may take 6 to
Table 1. Summary of the Gasifier Base Case Parameters Values and Uncertainties for the Oxygen-Blown KRW-based IGCC System with Cold Gas Cleanup (Conventional Design).

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Value</th>
<th>Distribution</th>
<th>Parameters&lt;sup&gt;a&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GASIFIER PROCESS AREA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasifier Pressure</td>
<td>psia</td>
<td>465</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasifier Temperature</td>
<td>°F</td>
<td>1,850</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall Carbon Conversion</td>
<td>wt-% of feed coal carbon</td>
<td>95</td>
<td>Triangular</td>
<td>75 to 95 (95)</td>
</tr>
<tr>
<td>Oxygen/Carbon Ratio</td>
<td>lbmole O₂/C</td>
<td>0.34</td>
<td>Uniform</td>
<td>0.33 to 0.35</td>
</tr>
<tr>
<td>Steam/Oxygen Ratio</td>
<td>lbmole H₂O/O₂</td>
<td>1.35</td>
<td>Uniform</td>
<td>1.1 to 1.6</td>
</tr>
<tr>
<td>Sulfur Retention in Bottom Ash</td>
<td>mol-% of inlet sulfur</td>
<td>15</td>
<td>Triangular</td>
<td>10 to 20 (15)</td>
</tr>
</tbody>
</table>

<sup>a</sup> For Uniform distributions, the lower and upper bounds are given. For the triangular distribution, the mode is given in parentheses. For the fractile distribution, the lower and upper bounds for each range are given, along with the probability of sampling within that range. For normal and lognormal distributions, the 99.8 percent probability range is given.

Table 2. Summary of the Gasifier Base Case Parameters Values and Uncertainties for the Air-Blown KRW-based IGCC System with Hot Gas Cleanup (Advanced Design).

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Value</th>
<th>Distribution</th>
<th>Parameters&lt;sup&gt;a&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GASIFIER PROCESS AREA</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasifier Pressure</td>
<td>psia</td>
<td>465</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gasifier Temperature</td>
<td>°F</td>
<td>1,900</td>
<td>Triangular</td>
<td>1,900 to 1,950 (1,900)</td>
</tr>
<tr>
<td>Overall Carbon Conversion</td>
<td>wt-% of feed coal carbon</td>
<td>95</td>
<td>Triangular</td>
<td>90 to 97 (95)</td>
</tr>
<tr>
<td>Oxygen/Carbon Ratio</td>
<td>lbmole O₂/C</td>
<td>0.46</td>
<td>Triangular</td>
<td>0.45 to 0.47 (0.46)</td>
</tr>
<tr>
<td>Steam/Oxygen Ratio</td>
<td>lbmole H₂O/O₂</td>
<td>0.45</td>
<td>Uniform</td>
<td>0.4 to 0.5</td>
</tr>
<tr>
<td>Sulfur Retention in Bottom LASH</td>
<td>mol-% of inlet sulfur</td>
<td>90</td>
<td>Triangular</td>
<td>85 to 95 (90)</td>
</tr>
<tr>
<td>Limestone Calcium-to-Sulfur Ratio</td>
<td>lbmole Ca/S</td>
<td>2.6</td>
<td>Triangular</td>
<td>2 to 2.8 (2.6)</td>
</tr>
<tr>
<td>Gasifier Ammonia Yield</td>
<td>Equiv. fraction of coal N to NH₃</td>
<td>0.10</td>
<td>Triangular</td>
<td>0.005 to 0.10 (0.10)</td>
</tr>
</tbody>
</table>

<sup>a</sup> For Uniform distributions, the lower and upper bounds are given. For the triangular distribution, the mode is given in parentheses. For the fractile distribution, the lower and upper bounds for each range are given, along with the probability of sampling within that range. For normal and lognormal distributions, the 99.8 percent probability range is given.
12 hours to run, depending on the flowsheet. However, while stochastic simulation requires an initial computer-intensive phase, the interpretation of results is much easier and more meaningful compared to sensitivity analysis.

MODEL APPLICATIONS AND RESULTS

Case study results of both IGCC systems are first reported individually. Then, the two systems are compared probabilistically. The results reported here focus on characterizations of uncertainty in plant emissions, performance, and cost. The model results are based on a 3.86 percent sulfur Illinois No. 6 coal.

Case 1: IGCC with CGCU

Results of both deterministic and probabilistic simulations of the performance, emissions, and cost of the IGCC system with CGCU are given in Table 3. The results for plant thermal efficiency, total capital cost, and the cost of electricity are shown also as cumulative distribution functions (cdfs) in Figures 3, 4, and 5, respectively.

Because of the negative skewness of the assumption regarding uncertainty in the gasifier carbon conversion efficiency (see Table 1), the plant thermal efficiency is also negatively skewed. The mode of the uncertainty in carbon conversion was taken to be at the upper bound of the distribution, and the modal value was used as the "best guess" in the deterministic analysis. The modal value of 95 percent carbon conversion is also widely assumed in conceptual design studies (e.g., Dawkins et al. [3]; Gallaspy et al. [14]). However, scale-up risks and inherent design limitations for the fluidized bed gasifier may lead to lower carbon conversions and, hence, lower plant efficiencies, than commonly assumed [15].

Although the oxygen-blown fluidized bed gasifier-based system considered here represents elements of "conventional" IGCC technology, particularly the cold gas cleanup system, there is still considerable performance and cost risk associated with the gasification process area. Uncertainty in both plant performance and capital cost-related parameters result in the uncertainty in total capital cost. Compared to the deterministic "best guess" estimate, which includes values of both process and project contingency factors typically assumed in the literature [12], there is a 70 percent probability of cost overrun. In contrast, contingency factors are not used in the probabilistic analysis; instead, explicit characterizations of uncertainty for process area direct costs and project construction costs are used. While estimates of uncertainties in capital cost parameters, including process area direct costs, were based on symmetric probability distributions, the underlying negative skewness of the major measures of plant performance, such as efficiency and coal consumption, shift the resulting capital cost uncertainty toward higher values than the "best guess." Thus, the interactions among performance and cost uncertainties, considered here, are shown to have important implications for capital cost.

The difference between the deterministic and probabilistic estimates of cost are more pronounced for the levelized cost of electricity. Recall that while typical cost estimating practices include capital cost contingency factors, there is no accepted systematic notion of contingencies with respect to fixed and variable operating costs. Performance uncertainties play a key role in driving uncertainty in levelized cost. The negative skewness of the carbon conversion rate leads to positive skewness in consumable requirements such as fuel (coal) and process water, and in the ash disposal rate. Furthermore, the unit costs associated with both ash disposal and byproduct recovery were assumed to have skewed distributions. In the case of ash disposal, it was assumed that costs could go up, but not down, due to increasingly stringent landfill requirements and associated difficulties in siting and complying with regulations. In the case of byproduct sale price, a negative skewness was assumed, representing the likelihood that market conditions at any
Table 3. Summary of Results from Deterministic and Probabilistic Simulations of a 650 MW Oxygen-Blown Fluidized Bed Gasifier-based IGCC System with Cold Gas Cleanup.a

<table>
<thead>
<tr>
<th>Parameterb</th>
<th>&quot;Best Unitsc</th>
<th>Guessd</th>
<th>f_{50}</th>
<th>μ</th>
<th>σ</th>
<th>f_{05} - f_{95}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant Performance</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thermal Efficiency</td>
<td>%, HHV</td>
<td>38.5</td>
<td>36.2</td>
<td>36.0</td>
<td>1.6</td>
<td>33.2 - 38.2</td>
</tr>
<tr>
<td>Coal Consumption</td>
<td>lb/kWh</td>
<td>0.788</td>
<td>0.839</td>
<td>0.845</td>
<td>0.038</td>
<td>0.794 - 0.914</td>
</tr>
<tr>
<td>Process Water Consump.</td>
<td>lb/kWh</td>
<td>0.779</td>
<td>0.803</td>
<td>0.812</td>
<td>0.051</td>
<td>0.733 - 0.896</td>
</tr>
<tr>
<td>Sulfur Production</td>
<td>lb/kWh</td>
<td>0.021</td>
<td>0.023</td>
<td>0.023</td>
<td>0.001</td>
<td>0.021 - 0.025</td>
</tr>
<tr>
<td>Plant Discharges</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂ Emissions</td>
<td>lb/MMBtu</td>
<td>0.342</td>
<td>0.335</td>
<td>0.334</td>
<td>0.012</td>
<td>0.311 - 0.352</td>
</tr>
<tr>
<td>NOₓ Emissions</td>
<td>lb/MMBtu</td>
<td>0.142</td>
<td>0.132</td>
<td>0.131</td>
<td>0.034</td>
<td>0.077 - 0.186</td>
</tr>
<tr>
<td>CO Emissions</td>
<td>lb/kWh</td>
<td>0.0001</td>
<td>0.0001</td>
<td>0.0001</td>
<td>2.2x10^{-5}</td>
<td>0.0001 - 0.0001</td>
</tr>
<tr>
<td>CO₂ Emissions</td>
<td>lb/kWh</td>
<td>1.68</td>
<td>1.68</td>
<td>1.67</td>
<td>0.021</td>
<td>1.63 - 1.70</td>
</tr>
<tr>
<td>Solid Waste</td>
<td>lb/kWh</td>
<td>0.079</td>
<td>0.084</td>
<td>0.084</td>
<td>0.004</td>
<td>0.079 - 0.091</td>
</tr>
<tr>
<td>Plant Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Capital Cost</td>
<td>$/kW</td>
<td>1,738</td>
<td>1,796</td>
<td>1,806</td>
<td>99</td>
<td>1,645 - 1,985</td>
</tr>
<tr>
<td>Fixed Operating Cost</td>
<td>$/kW-yr</td>
<td>54.4</td>
<td>57.1</td>
<td>56.8</td>
<td>4.4</td>
<td>49.4 - 64.2</td>
</tr>
<tr>
<td>Variable Operating</td>
<td>mills/kWh</td>
<td>16.2</td>
<td>17.6</td>
<td>17.8</td>
<td>08</td>
<td>16.6 - 19.4</td>
</tr>
<tr>
<td>Coal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Byproduct</td>
<td>(1.2)</td>
<td>(1.1)</td>
<td>(1.1)</td>
<td>0.2</td>
<td>(0.8)</td>
<td>(1.3)</td>
</tr>
<tr>
<td>Other</td>
<td>1.2</td>
<td>1.4</td>
<td>1.4</td>
<td>0.2</td>
<td>1.2</td>
<td>1.7</td>
</tr>
<tr>
<td>Cost of Electricity</td>
<td>mills/kWh</td>
<td>57.3</td>
<td>60.5</td>
<td>60.5</td>
<td>2.6</td>
<td>56.4 - 65.6</td>
</tr>
</tbody>
</table>

a The notation in the table heading is defined as follows: f_{n} = n^{th} fractile (f_{50} = median), μ = mean; and σ = standard deviation of the probability distribution. The range enclosed by f_{05} to f_{95} is the 90 percent probability range. All costs are January 1989 dollars.
b Coal consumption is on an as-received basis. Water consumption is for process requirements including makeup for steam cycle blowdown, gasifier steam, and zinc ferrite steam. Solid waste includes gasifier bottom ash and nonrecycled fines from fuel gas cyclones.
c HHV = higher heating value; MMBtu = million Btu.
d Based on a deterministic simulation in which median or modal values of uncertain variables are assumed as "best guess" inputs to the model.
Figure 3. Comparison of Deterministic and Probabilistic Results for the Net Plant Thermal Efficiency of the Oxygen-blown KRW-based System (CGCU).

Figure 4. Comparison of Deterministic and Probabilistic Results for the Total Capital Cost of the Oxygen-blown KRW-based System (CGCU).

Figure 5. Comparison of Deterministic and Probabilistic Results for the Cost of Electricity of the Oxygen-blown KRW-based System (CGCU).
given location in the U.S. may not be favorable to obtaining the maximum world market price. Thus, cost-related uncertainties are also important contributors to uncertainty in leveled costs.

The interactions among uncertainties in performance, capital cost, maintenance cost, and unit cost uncertainties result in the difference between the deterministic and probabilistic estimates for cost of electricity. Here, the deterministic estimate has an associated 90 percent probability of cost overrun. Furthermore, while the cost of electricity could be perhaps 2 mills/kWh less than the "best guess," it could be over 10 mills/kWh (15 to 20 percent) higher.

Case 2: IGCC with HGCU

A summary of the deterministic and probabilistic results for key performance, emissions, and cost variables for the air-blown fluidized bed gasifier IGCC with HGCU is given in Table 4. The analyses are based on the parameter values given in Frey [13]. For many of the results, the deterministic, median, and mean values are similar, indicating that uncertainties in this process are not strongly skewed, as for the previous case study. A few of the results are discussed here briefly.

The uncertainty in the plant thermal efficiency is shown in Figure 6, and it is compared to the deterministic estimate. The uncertainty in efficiency covers a 90 percent probability range of less than 2 percentage points, and the mean, median, and deterministic values approximately coincide. The distribution is slightly skewed toward lower values. This result is expected due to the negative skewness of the uncertainty in carbon conversion. The range of uncertainty is substantially less than for the previous case study, due in part to the lower range of uncertainty regarding gasifier carbon conversion and the use of a boiler to combust unconverted carbon leaving the gasifier.

The NO\textsubscript{X} emissions from the air-blown IGCC system are substantially higher than that for the system with CGCU, and may be unacceptably high. The use of post-combustion emission control using SCR or the development of advanced combustors that minimize fuel NO\textsubscript{X} formation may be required. SCR is the nearest term alternative. It would increase costs and modestly reduce plant efficiency, due to auxiliary power requirements and increased gas turbine back pressure. SCR is not considered in the present study.

In Figure 7, the uncertainty in total capital cost is compared to the deterministic estimate. Unlike the previous case study, the deterministic estimate, which includes process and project contingency factors, coincides with the median value of the probabilistic simulation. Thus, there is a 50 percent chance of cost overrun associated with the deterministic estimate of $1,380/kW. Because the performance parameter uncertainties were symmetric or only moderately skewed, and because all of the cost related uncertain parameters affecting capital cost were assumed to be symmetrically distributed, the uncertainty in capital cost is approximately symmetric. The 90 percent probability range for capital cost is $255/kW.

In spite of the agreement between the deterministic and probabilistic results for capital cost, the two analyses do not agree with respect to the cost of electricity, as seen in Figure 8. There is a 75 percent probability that the cost will be higher than the deterministic estimate. In the probabilistic analysis, the uncertainties in the maintenance cost of the gas turbine, zinc ferrite, and sulfation process areas were assumed to be positively skewed. Also, the unit costs of limestone and ash disposal were assumed to be positively skewed. These assumptions affect fixed and variable operating cost and, in turn, the cost of electricity.

From other analyses reported by Frey [13], it is clear that performance-related uncertainties are a relatively minor component of overall uncertainty in cost for this technology. Furthermore, while the variance in the result for the cost of electricity is strongly influenced by uncertainties in capital cost, it is the uncertainties in O&M costs that are responsible for the shift in the central
Table 4. Summary of Results from Deterministic and Probabilistic Simulations of a 730 MW Air-Blown Fluidized Bed Gasifier-based IGCC System with Hot Gas Cleanup.\textsuperscript{a}

<table>
<thead>
<tr>
<th>Parameter\textsuperscript{b}</th>
<th>&quot;Best&quot; Units\textsuperscript{c}</th>
<th>Guess\textsuperscript{d}</th>
<th>f\textsubscript{0.50}</th>
<th>(\mu)</th>
<th>(\sigma)</th>
<th>f\textsubscript{0.05} -</th>
<th>f\textsubscript{0.95}</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Plant Performance</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thermal Efficiency</td>
<td>%, HHV</td>
<td>41.1</td>
<td>41.1</td>
<td>41.0</td>
<td>0.5</td>
<td>40.1 -</td>
<td>41.8</td>
</tr>
<tr>
<td>Coal Consumption</td>
<td>lb/kWh</td>
<td>0.739</td>
<td>0.739</td>
<td>0.741</td>
<td>0.009</td>
<td>0.727 -</td>
<td>0.758</td>
</tr>
<tr>
<td>Process Water Consump.</td>
<td>lb/kWh</td>
<td>0.727</td>
<td>0.738</td>
<td>0.740</td>
<td>0.016</td>
<td>0.716 -</td>
<td>0.771</td>
</tr>
<tr>
<td>ZF Sorbent Charge</td>
<td>(\times 10^6) lb</td>
<td>4.57</td>
<td>4.63</td>
<td>4.63</td>
<td>0.104</td>
<td>4.47 -</td>
<td>4.82</td>
</tr>
<tr>
<td>Byproduct</td>
<td>N/A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Plant Discharges</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO\textsubscript{2} Emissions</td>
<td>lb/MMBtu</td>
<td>0.013</td>
<td>0.014</td>
<td>0.014</td>
<td>0.001</td>
<td>0.013 -</td>
<td>0.016</td>
</tr>
<tr>
<td>NO\textsubscript{x} Emissions</td>
<td>lb/MMBtu</td>
<td>0.714</td>
<td>0.507</td>
<td>0.487</td>
<td>0.137</td>
<td>0.269 -</td>
<td>0.714</td>
</tr>
<tr>
<td>CO Emissions</td>
<td>lb/kWh</td>
<td>0.005</td>
<td>0.005</td>
<td>0.005</td>
<td>0.003</td>
<td>0.004 -</td>
<td>0.009</td>
</tr>
<tr>
<td>CO\textsubscript{2} Emissions</td>
<td>lb/kWh</td>
<td>1.71</td>
<td>1.71</td>
<td>1.71</td>
<td>0.024</td>
<td>1.68 -</td>
<td>1.75</td>
</tr>
<tr>
<td>Solid Waste</td>
<td>lb/kWh</td>
<td>0.228</td>
<td>0.228</td>
<td>0.227</td>
<td>0.012</td>
<td>0.205 -</td>
<td>0.247</td>
</tr>
<tr>
<td><strong>Plant Costs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Capital Cost</td>
<td>$/kW</td>
<td>1.381</td>
<td>1.375</td>
<td>1.376</td>
<td>75</td>
<td>1.251 -</td>
<td>1.516</td>
</tr>
<tr>
<td>Fixed Operating Cost</td>
<td>$/kW-yr</td>
<td>45.1</td>
<td>48.2</td>
<td>48.9</td>
<td>4.2</td>
<td>42.6 -</td>
<td>56.6</td>
</tr>
<tr>
<td>Variable Operating</td>
<td>mills/kWh</td>
<td>19.4</td>
<td>20.2</td>
<td>20.2</td>
<td>0.6</td>
<td>19.3 -</td>
<td>21.3</td>
</tr>
<tr>
<td>Coal</td>
<td></td>
<td>15.2</td>
<td>15.2</td>
<td>15.2</td>
<td>0.6</td>
<td>15.0 -</td>
<td>15.6</td>
</tr>
<tr>
<td>Byproduct</td>
<td>N/A</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td></td>
<td>4.3</td>
<td>4.9</td>
<td>4.9</td>
<td>0.5</td>
<td>4.2 -</td>
<td>5.9</td>
</tr>
<tr>
<td>Cost of Electricity</td>
<td>mills/kWh</td>
<td>52.5</td>
<td>53.8</td>
<td>53.8</td>
<td>2.0</td>
<td>50.3 -</td>
<td>57.1</td>
</tr>
</tbody>
</table>

\textsuperscript{a} The notation in the table heading is defined as follows: \(f_n = n^{th}\) fractile (\(f_{0.50}\) = median), \(\mu\) = mean; and \(\sigma\) = standard deviation of the probability distribution. The range enclosed by \(f_{0.05}\) to \(f_{0.95}\) is the 90 percent probability range. All costs are January 1989 dollars.

\textsuperscript{b} Coal consumption is on an as-received basis. Water consumption is for process requirements including makeup for steam cycle blowdown, gasifier steam, and zinc ferrite steam. Solid waste includes gasifier bottom ash and nonrecycled fines from fuel gas cyclones.

\textsuperscript{c} HHV = higher heating value; MMBtu = million Btu.

\textsuperscript{d} Based on a deterministic simulation in which median or modal values of uncertain variables are assumed as "best guess" inputs to the model.
Figure 6. Comparison of Deterministic and Probabilistic Results for the Net Plant Thermal Efficiency of the Air-blown KRW-based System (HGCU).

Figure 7. Comparison of Deterministic and Probabilistic Results for the Total Capital Cost of the Air-blown KRW-based System (HGCU).

Figure 8. Comparison of Deterministic and Probabilistic Results for the Cost of Electricity of the Air-blown KRW-based System (HGCU).
tendency of the distribution compared to the deterministic estimate. Thus, the risk of cost growth is associated primarily with the operating costs of the hot gas cleanup system.

Probabilistic Comparative Analysis

The preceding sections have focused on individual case studies of each IGCC technology. In this section, the two systems will be compared in the face of uncertainty. These comparisons are based on key measures of plant performance, emissions, and cost. For both technologies, additional research is likely to reduce uncertainties in both performance and cost. Therefore, sensitivity cases based on alternative assumptions regarding process uncertainties are considered.

Comparing Alternatives Probabilistically

Comparisons between the two technologies are based on probability distributions for the differences in performance, emissions, and cost. When comparing systems probabilistically, it is necessary to consider model parameters and uncertainties that are common to both systems. In such instances, the same set of sample values and ranking of values must be used in the probabilistic simulation of both technologies, in order to account for any underlying correlations between the two systems.

Several of the variables common to, or similar between, both flowsheets are assumed to be completely correlated. Examples of these include uncertainty in the direct capital cost of the gas turbine and general facilities process areas, the standard errors of the regression models used to estimate the heat recovery steam generator and steam turbine direct costs, the cost of ash disposal, and several indirect capital cost parameters.

Other uncertain parameters that are similar between the systems are assumed to be uncorrelated. For example, although the performance of the two gasifiers can be characterized using similar parameters, the systems are sufficiently different that no correlations are assumed to exist among them.

Based on the pairing of input uncertainties, the results of probabilistic simulations of the two IGCC systems for several key measures of plant performance, emissions, and cost were then paired, sample by sample. Each pair of samples was subtracted, and the resulting set of sample differences were used to construct cdfs for the performance, emissions, or cost savings of the advanced technology compared to the conventional technology.

The risk that the new technology will be more expensive can be quantified using the partial mean of the cost difference distribution for all negative values. The downward and upward partial means are defined as [16]:

\[ \mu_d(x) = \int_x^0 f(x) \, dx \]  
\[ \mu_u(x) = \int_0^x f(x) \, dx \]  

where \( f(x) \) is the probability density function for the random variable \( x \). Buck and Askin define the conditional partial mean based on the partial mean and the probability that a loss or gain has occurred. The expected value of a loss, given that a loss has occurred, is:

\[ \mu_{d|x<0}(x) = \frac{\mu_d(x)}{P(x<0)} \]
where $P(x < 0)$ is the probability that the random variable $x$ has a value less than zero. The expected value of a gain, given that a gain has occurred, is defined similarly.

**Effect of Additional Research**
Additional research on both of the IGCC systems can be expected to reduce the magnitude of uncertainties in these technologies. Reduction in the uncertainties in one or both technologies affects the probability distribution for the differences between the two. Therefore, several comparisons are made for each key output variable, based on alternative combinations of base case and reduced uncertainty assumptions for the two technologies. Details of the assumptions are discussed by Frey [13]. The multiple set of comparisons provides insight into whether the advantage seen for one technology is robust when the underlying assumptions change.

**Modeling Results**
The results of the paired simulations of the two flowsheets were obtained, accounting for the underlying correlation between the two cases. For base case uncertainty assumptions, the correlation between the total capital costs uncertainties of the two systems was 0.75, and the correlation between levelized costs was 0.54. These correlations significantly affect the comparative results. Because of the positive correlation between the systems, the range of uncertainty in the differences between them is less than if they were completely uncorrelated.

The statistics associated with the probability distributions of the differences between the two technologies are summarized in Table 5 for selected measures of plant performance, emissions, and cost. From the table, it is clear that the air-blown system is either markedly better or worse than the conventional system for a given attribute; there is little ambiguity regarding the comparisons.

The system with HGCU holds clear advantages with respect to plant efficiency, SO$_2$ emissions, total capital cost, and cost of electricity. It is likely to have lower water consumption and lower fixed operating cost. However, it is certain to have higher variable operating cost and higher NO$_x$ emissions. It is also likely to have higher CO$_2$ emissions in spite of its higher efficiency.

The efficiency advantage of the system with HGCU is attributable to the reduction in fuel gas cooling, a lower auxiliary power requirement for oxidant feed, and combustion of unconverted carbon in the gasifier ash to generate steam in the sulfation unit. However, in spite of substantially higher efficiency, the air-blown system has over an 80 percent probability of higher CO$_2$ emissions. This result is obtained because of the use of a limestone sorbent for desulfurization in the gasifier. The calcium carbonate in the limestone is calcined in the gasifier, releasing CO$_2$. The carbon retained in the bottom ash that is combusted in the sulfation unit is an additional source of CO$_2$ emissions. In the conventional system, unconverted carbon is sequestered in the bottom ash.

Because of the additional burden of spent limestone sorbent in the air-blown system, the ash disposal requirement will be higher than for the conventional system. The CGCU system converts sulfur in the fuel gas to a elemental sulfur, thereby reducing the solid waste burden and generating a byproduct revenue stream.

The air-blown IGCC system with HCGU will have lower capital cost, due to the reduction in equipment cost associated with fuel gas cooling and cleanup and substitution of a boost air compressor for the air separation plant. The expected cost savings is over $400/kW, regardless of the assumptions regarding uncertainties, as indicated in Table 5.

There is a low probability that the fixed operating cost of the air-blown system could be higher than for the conventional system, due to the risks of contaminant-related problems in the HGCU system. However, regardless of assumptions regarding uncertainties, the air-blown system will have higher operating costs than the conventional system. The advanced system has
<table>
<thead>
<tr>
<th>Research Area b</th>
<th>Probability of a Loss (%)</th>
<th>Downward Partial Mean</th>
<th>Expected Value of a Loss</th>
<th>Expected Value of a Gain</th>
<th>Mean</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Plant Efficiency, percent</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5.0</td>
<td>5.0</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Base</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5.1</td>
<td>5.1</td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3.9</td>
<td>3.9</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4.0</td>
<td>4.0</td>
</tr>
<tr>
<td><strong>CO2 Emissions, lb/kWh</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>89</td>
<td>0.042</td>
<td>0.048</td>
<td>0.009</td>
<td>-0.041</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Base</td>
<td>95</td>
<td>0.039</td>
<td>0.041</td>
<td>0.006</td>
<td>-0.039</td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>83</td>
<td>0.031</td>
<td>0.037</td>
<td>0.009</td>
<td>-0.029</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>89</td>
<td>0.027</td>
<td>0.030</td>
<td>0.004</td>
<td>-0.027</td>
</tr>
<tr>
<td><strong>Ash Disposal Rate, lb/kWh</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>100</td>
<td>0.153</td>
<td>0.153</td>
<td>0</td>
<td>-0.153</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Base</td>
<td>100</td>
<td>0.153</td>
<td>0.153</td>
<td>0</td>
<td>-0.153</td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>100</td>
<td>0.155</td>
<td>0.155</td>
<td>0</td>
<td>-0.155</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>100</td>
<td>0.155</td>
<td>0.155</td>
<td>0</td>
<td>-0.155</td>
</tr>
<tr>
<td><strong>Total Capital Cost, 1989 $/kW</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>428</td>
<td>428</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Base</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>425</td>
<td>425</td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>417</td>
<td>417</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>414</td>
<td>414</td>
</tr>
<tr>
<td><strong>Fixed Operating Cost, 1989 $/A-W-yr</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>9</td>
<td>0.16</td>
<td>1.77</td>
<td>8.84</td>
<td>7.88</td>
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<td>HGCU Reduced vs. CGCU Base</td>
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<td>0.009</td>
<td>0.9</td>
<td>9.73</td>
<td>9.63</td>
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<tr>
<td>HGCU Base vs. CGCU Reduced</td>
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<td>0.03</td>
<td>1.1</td>
<td>8.39</td>
<td>8.10</td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
<td>9.85</td>
<td>9.85</td>
</tr>
<tr>
<td><strong>Variable Operating Cost, 1989 mills/kWh</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>100</td>
<td>2.5</td>
<td>2.5</td>
<td>0</td>
<td>-2.5</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Base</td>
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<td>2.5</td>
<td>2.5</td>
<td>0</td>
<td>-2.5</td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>100</td>
<td>3.0</td>
<td>3.0</td>
<td>0</td>
<td>-3.0</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>100</td>
<td>3.0</td>
<td>3.0</td>
<td>0</td>
<td>-3.0</td>
</tr>
<tr>
<td><strong>Levelized Cost of Electricity, Constant 1989 mills/kWh</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HGCU Base vs. CGCU Base</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>6.6</td>
<td>6.6</td>
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<tr>
<td>HGCU Reduced vs. CGCU Base</td>
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<td>0</td>
<td>0</td>
<td>6.9</td>
<td>6.9</td>
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<tr>
<td>HGCU Base vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5.9</td>
<td>5.9</td>
</tr>
<tr>
<td>HGCU Reduced vs. CGCU Reduced</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>6.2</td>
<td>6.2</td>
</tr>
</tbody>
</table>

a HGCU=Hot Gas Cleanup; CGCU=Cold Gas Cleanup. The comparison is from the perspective of the air-blown IGCC system with HGCU. Thus, "loss" in this case is a probability that the system with HGCU will be worse (lower efficiency, higher emissions, higher cost) in a given attribute than the system with CGCU.

b For each parameter used for comparison, the results are grouped separately for comparisons of the air-blown IGCC system with hot gas cleanup (HGCU) to the base case and "All" reduced uncertainties case for the oxygen-blown IGCC system with cold gas cleanup (CGCU).
higher costs associated with limestone and zinc ferrite sorbents, and disposal of spent limestone sorbent and ash.

Overall, the advanced system will enjoy levelized cost savings over the conventional system. The uncertainty in the levelized cost savings is shown graphically in Figure 9. The solid lines represent comparisons to the base case uncertainties for the conventional system, while the dashed lines represent comparisons to the reduced uncertainties case for the conventional system. While research on the conventional system will tend to reduce the expected cost savings of the advanced systems, the cost savings remain substantial nonetheless. Savings of over 2 mills/kWh are obtained from the analysis for all cases. The mean cost savings are typically 6 mills/kWh, with a chance that cost savings could be 10 mills/kWh or higher.

The advantage of the air-blown system with hot gas cleanup is diminished as the plant capacity factor increases, because of its higher variable operating costs. However, the levelized costs for the system with HGCU are sufficiently low that it continues to have a 100 percent probability of cost savings even at a 90 percent capacity factor.

CONCLUSIONS

Assessments of advanced process technologies that are in early stages of development should be based on a proper understanding and representation of uncertainties. For both of the IGCC systems evaluated here, deterministic estimates based on "best guess" values substantially underestimated levelized costs, as compared to the probabilistic estimates. Thus, probabilistic analysis has implications for the development of more realistic cost estimates that capture the notion of "cost growth" often experienced with innovative process technologies. The case studies presented here include uncertainty estimates based on a combination of elicited expert judgments, data analysis, and preliminary judgments by the authors. The results of these case studies can be used to prioritize parameters for which improved estimates regarding uncertainties are warranted, such as sorbent-related unit costs.

In the technology-specific comparisons presented here, the system with hot gas cleanup is shown to offer advantages over a system with cold gas cleanup with respect to plant efficiency, SO₂ emissions, and capital and levelized costs. Because of the sorbent requirements for the case examined here, the solid waste burden of the system with hot gas cleanup is substantially higher than for the conventional system. Also, the system with HGCU exhibits significantly higher operating costs than that with CGCU. The robustness of the results obtained to different
assumptions regarding uncertainties provides additional confidence in the qualitative conclusions. However, additional design changes may be required to reduce NOx emissions to acceptable levels: the additional costs associated with either combustor design modifications or post-combustion controls, if required, could affect the qualitative comparisons reported here. The ability to test both the implications of uncertainties and of different assumptions regarding uncertainties is a powerful tool for technology evaluation and research planning.

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