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Project Summary

Technoeconomic Appraisal of Integrated Gasification Combined-Cycle Power Generation

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A future competitive technology to current pulverized-coal boilers equipped with SO_2 and NO_x controls is the integrated (coal) gasification combined-cycle (IGCC) system, because of its potential for increased thermal efficiency and very low emission rates. However, IGCC is not yet a proven commercial technology; this fact will influence the rate of market penetration of IGCC and its possible impact on future emissions. Several private firms, working with the Electric Power Research Institute (EPRI), have demonstrated the first IGCC plant to supply electricity to a U.S. utility system at Southern California Edison Co.'s Cool Water Generating Station near Barstow, CA, using Texaco's coal gasification process. This demonstration has provided significant data for process improvements and has indicated the basic operability of combined chemical process/power generation technology. However, remaining technical questions include: operability of the Texaco gasifier at full throughput; materials of construction; plant operation over an extended period of time with high-sulfur eastern coal; and plant availability/reliability. The most significant gasification technologies, in terms of potential application to IGCC systems, appear to be Texaco, Dow, British Gas Corporation (BGC)/Lurgi, and Shell. One advantage of IGCC systems is their potential for phased construction of partial plant capacity to more closely match the currently slow electricity demand growth. Simple comparisons using generic cost and performance data indicate similar electricity generation costs for IGCC and competing technologies. The projected market of about 57,000 MW for new gas turbines from 1990 to 2010 should provide significant opportunity for phased IGCC systems.

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Background

Projections into the next century of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from U.S. coal-based electric generating plants are significantly affected by the many assumptions that must be made. These assumptions include: the rate at which existing coal-fired boilers will be retired, as opposed to being overhauled for life extension purposes; the rate at which new coal-based generating units will be built, either to replace retired capacity or to increase generating capacity from current levels;

and the technologies that will be used in these new units. One technology that is emerging as a future competitor to current pulverized-coal (PC) boilers equipped with pollution control devices [(e.g., low-NO_x burners and flue gas desulfurization (FGD)] is integrated (coal) gasification combined-cycle (IGCC) systems because of their potential for increased thermal efficiency and very low SO_2 and NO_x emission rates.

However, IGCC plants are not yet a proven commercial technology with demonstrated benefits and reliably competitive costs. Thus, there are technical risks associated with IGCC. Because these technical risks and the perceived economics of IGCC will influence its actual rate of penetration, and its possible impact on expected future emissions, the EPA authorized an independent technical and economic assessment of IGCC systems.

This study involved three tasks corresponding to three main objectives: (1) technical evaluation of IGCC technologies and systems, (2) developing cost and performance estimates and comparing IGCC with competing coal-burning technologies, and (3) evaluating the potential future market for IGCC application to new power generating plants.

In an IGCC plant, coal is fed to a gasifier, where it reacts with steam and oxygen to produce a hot raw fuel gas. The fuel gas is then cooled and purified to remove particulates and acid gas (hydrogen sulfide). Elemental sulfur is recovered from the acid gas. The clean fuel gas is burned in a 1090+°C combustion turbine. The hot flue gas (480-540°C) leaving the combustion turbine is cooled by generating, superheating, and reheating steam in a heat recovery steam generator. This steam is used in a steam turbine. Power is generated from both the combustion turbines and the steam turbines. The primary reason for integrating the gasification system with the combined-cycle plant is that doing so substantially improves the overall system energy efficiency or heat rate.

Although all components (i.e., gasifiers, gas coolers, acid gas removal systems, combined cycles) included in an IGCC configuration have, in some way, been demonstrated to operate at full commercial scale, they have only recently been operated in unison in a complete system to generate electric power. Integrated control and operation of such plants in a commercial environment must be demonstrated on a large scale before the majority of the electric utility industry will seriously consider adopting IGCC systems for electric power generation. Taking a step closer to this goal by resolving some of these issues is one of the central objectives of the Cool Water Gasification Program, an IGCC demonstration based on Texaco's coal gasification technology.

Cool Water Demonstration IGCC Plant

The Cool Water Gasification Program is an undertaking of a number of private entities, led by EPRI, to design, construct, and operate the nation's first IGCC power plant to supply electricity to a utility system. The demonstration plant, consisting of commercial-scale components and subsystems, is at the Cool Water Generating Station of Southern California Edison Company (SCE) near Barstow, CA, about halfway between Los Angeles and Las Vegas in the Mojave Desert. The Cool Water plant began generating electricity on June 24, 1984, and is being operated by the program for a 5-year demonstration period. It is the goal of the program to demonstrate the environmental and economic characteristics of an IGCC power generation plant.

The Cool Water plant uses an entrained-bed, oxygen-blown Texaco gasifier to convert 1000 tons (907 x 10^3 kg) of coal per day to a medium-Btu synthesis gas for power production. The net plant output is 90 to 100 MW, depending on operating conditions. The program coal is a specified Utah run-of-mine coal with approximately 0.5 wt. % sulfur. The program has also tested Illinois No. 6 coal, containing 3.1 wt. % sulfur, and Pittsburgh No. 8 coal, containing 2.8 wt. % sulfur.

Gasifier performance at the Cool Water plant has been better than originally expected. Single-pass carbon conversions have been greater than 98 wt. % when the plant is operated on Utah coal. Also, the high carbon conversions are being attained at lower reaction temperatures than originally expected. The lower gasification temperatures have reduced oxygen costs and extended refractory life. Actual oxygen consumption has been 6% lower than the design value. Gasifier refractory life is presently estimated to be 3-year actual versus a 1-year design value on low-sulfur Utah coal.

Plant heat rates have also been in line with the original projections of 11,300 Btu, kWh (11,920 kJ/kWh). The Cool Water plant's high heat rate is the result of several early design decisions to reduce front-end project costs for the IGCC demonstration. This heat rate has been adjusted by EPRI to account for differences in equipment and conditions to coincide with an estimated heat rate for a commercial Texaco-based IGCC plant of 9,010 Btu/kWh (9,500 kJ/kWh). The plant does not, for example, use a reheat steam turbine, and the gas turbine is a less efficient current version. Table 1 lists the main differences in equipment and conditions between the Cool Water plant and an anticipated commercial plant, and the effects on system performance. Equipment sparing was also minimized.

One major goal of the Cool Water demonstration plant is to obtain a comprehensive package of data demonstrating the environmental acceptability of the technology. Overall, the environmental performance of the plant appears to be satisfactory during operations with all three of the coals tested to date. The data on overall emissions from Cool Water (based on results from continuous monitoring averaged over 3 to 6 hours when the plant was operating at full load) versus the U.S. EPA New Source Performance Standards (NSPS) are shown in Table 2. The Cool Water plant's SO_2 emissions are typically 10 to 20% of the allowable levels under EPA's NSPS for coal-fired power plants with stack-gas scrubbers. Sulfur removal from the synthetic gas (syngas) has ranged from 97 to 99%. Overall sulfur recovery from the feed coal is typically 97%. Stack emissions of NO_x and particulates have also averaged about 10% of allowable levels under the NSPS. NO_x emissions are controlled by steam injection or water saturation of the fuel gas prior to combustion in the gas turbine.

The most significant operating problem to date has been the failure of the radiant syngas cooler that occurred in December 1986. A crack appeared in the top of the radiant cooler, apparently due to a hot spot that developed there. The hot spot was attributed to plugging in the crossover duct between the radiant and the convection coolers, leading to maldistribution of the hot gas in the radiant cooler. The crossover duct was redesigned to eliminate plugging, the cooler was repaired, and the main gasifier went back in service in June 1987. While the main gasifier was being repaired, the plant continued operating with the backup quench gasifier.

Table 1. *Adjustment of Cool Water Heat Rate and Comparison with Estimate for a Commercial Plant*

	Data in Btu/kWh (kJ/kWh) Heat Rate Adjustment	EPRI Adjusted Cool Water Heat Rate	Estimated Commercial Plant Heat Rate
Cool Water Design Heat Rate		11,363 (11,986)	
Correction for Reheat Steam Cycle (Cool Water uses non-reheat steam cycle with lower steam temperature compared to commercial design.)	380 (401)		
Correction for Slurry Concentration (Cool Water uses 60% coal slurry feed versus 66.5% for commercial design.)	300 (316)		
Correction for ISO[a] Ambient Conditions for Gas Turbine (Cool Water heat rate is evaluated at 27°C versus 15°C ambient as a standard condition.)	230 (243)		
Corrections for Oxygen Purity, Saturator, 1105°C Gas Turbine (Cool Water uses higher-pressure, purer oxygen than is necessary and a 1085°C turbine.)	601 (634)	9,852 (10,392)	
Correction for Plant Size (Scaling up Cool Water to a commercial size would reduce plant auxiliary loads as a fraction of gross power generation.)	356 (376)	9,496 (10,016)	9,490 (10,000)
Correction for 1260°C Gas Turbine	486 (513)	9,010 (9,504)	9,009 (9,503)

[a] International Standards Organization.

Table 2. *Heat Recovery Steam Generator (HRSG) Stack Emissions from the Cool Water Plant*

Data in lb/10^6 Btu (kg/GJ)

	Permit Limit[a]	SUFCO[g] 1985 EPA Test	Ill. No. 6 EPA Test	Pitts. No. 8 Source Test	Federal NSPS[b]
SO_2 (High S)[c]	0.16 (0.68)		0.068 (0.029)	0.122 (0.052)	0.6[d] (0.257)
SO_2 (Low S)[c]	0.33 (0.14)	0.018 (0.008)			0.24[e] (0.103)
NO_x	0.13 (0.056)	0.07 (0.030)	0.004 (0.002)	0.066 (0.028)	0.6[d] (0.257)
CO	0.07 (0.030)	0.004 (0.002)	0.004 (0.002)	<0.002 (<0.001)	NS[f]
Particulates	0.0-1 (0.004)	0.001 (<0.001)	0.009 (0.004)	0.009 (0.004)	0.03 (0.013)

[a] Emission limits from EPA permit (based on design estimates of plant emissions).
[b] New Source Performance Standards for a coal-fired power plant burning equivalent coal as Cool Water.
[c] In the context of the Cool Water plant and its permit, high-sulfur coal is defined as coal containing more than 0.7 wt. % S and less than 3.5 wt. % S. Low-sulfur coal is defined as coal containing less than 0.7 wt. %S.
[d] Emissions controlled to 0.6 lb/10^6 Btu.
[e] 0.8 lb/10^6 Btu uncontrolled emissions x 0.03 for controlled emissions.
[f] NS: no standard.
[g] Southern Utah Fuels Co.

The gasifier, heat recovery steam generator, and gas turbine have all operated reliably. No changes in their fundamental designs are deemed necessary as a result of being tested as components of an IGCC system at Cool Water.

The costs of the Cool Water Project—capital, operating, and maintenance costs—have been collected and assessed by the program, and economic evaluations continue. The Cool Water plant is a demonstration project of commercial-scale components for only a single train and not a complete, up-to-date, commercial multi-train plant, using the most advanced technology and operating in an independent commercial environment. The plant receives financial backing from the U.S. Synthetic Fuels Corporation in the form of price guarantees. Thus, Cool Water costs provide only an indication of what potential costs might be for a truly commercial plant.

As a result of the experience gained with the Cool Water project, a second-generation demonstration IGCC plant similar to Cool Water could probably be built at lower cost, because no problems were encountered whose solution required redesign or plant modifications leading to increased costs. For example, it was learned that the radiant syngas cooler was grossly overdesigned since it produces over 90% of the total steam produced in the syngas coolers. A smaller syngas cooler could lead to a more optimum cooler design combination and lower costs.

The Cool Water operation is apparently a successful near-commercial-scale demonstration in every respect. However, because of various cost constraints, the plant was never designed to compete economically and requires financial guarantees to operate. On the other hand, the Cool Water experience has provided significant data leading to process improvements and indicating the basic operability and success of combining chemical process technology with power generation. Cool Water data, when extrapolated and analyzed, support the *potential* of IGCC technologies

Although the Cool Water plant has been successful, technical questions must be resolved before utilities will embrace even Texaco-based IGCC technology in a significant way. Some of these technical questions are:

- Operability of the Texaco gasifier at full throughput.
- Materials of construction.
- Plant operation over an extended period of time with high-sulfur eastern coals.
- Plant availability/reliability.

Only a successful demonstration designed to be competitive in a commercial environment with the advanced technology and operated over a satisfactorily long runtime can resolve these questions.

Gasification Systems

It is possible to design an IGCC system in a variety of configurations with a number of different technologies to meet various objectives. The most important technology choice influencing system performance and costs is, however, the gasification technology. Several different types of gasifiers are actively being developed and are in different stages of demonstration. EPRI has sponsored a series of design and cost-estimate studies that illustrate the merits of each technology and its recent status of development. In addition, a comprehensive evaluation and comparison of coal gasification technologies is available in the relatively recent literature.

The most important gasification technologies (based on their state of development), in terms of their near- or mid-term potential application to IGCC systems, appear to be Texaco, Dow, British Gas Corporation/Lurgi, and Shell.

Other technologies have been evaluated for this application but appear to be less well known or less developed, with fewer resources being available to support their full development. Table 3 compares the most important gasification technologies in terms of their commercial and development status.

The technological status of IGCC design is a function of the type of gasification system. The several gasification technologies being developed for IGCC application are in different stages of development with different kinds and amounts of technical risk.

- Texaco-based systems are further along in being demonstrated at commercial scale and so carry less risk, although certain questions remain to be resolved.
- Less advanced in being demonstrated, the Shell gasifier is still in the pilot-plant stage, and the BGC/Lurgi gasifier has reached prototype size. Scale-up of these gasifiers to commercial size may yet reveal serious problems requiring R&D for their resolution.
- The Dow system is being demonstrated at commercial scale but cannot be considered commercial because no information is available on its operation and financial guarantees (from the Synthetic Fuels Corporation) were apparently required to make the technical and economic risks involved acceptable.

At this point in time, there do not appear to be any insurmountable development requirements which might prevent IGCC technology from achieving its technical potential.

Advanced Gas Turbines

Since the efficiency of gas turbines increases as the inlet gas temperature is increased, recent developments in advanced materials and designs have led to stationary turbines that operate at ever higher temperatures. The current commercially available General Electric (GE) Model MS7001F gas turbine has an operating temperature of 1260°C. This model recently replaced Model MS7001E, which operated at 1095°C. This new turbine incorporates the latest technology in the compressor, combustion system, and turbine designs.

The only emissions currently controlled with the Federal NSPS for gas turbines are NO_x emissions. For utility turbines generating more than 9 MW (30 MW thermal), NO_x generation is restricted to 75 ppm. The older Model MS7001E gas turbine in an IGCC setting generated about 40 ppm, while the newer Model MS7001F generates about 50 ppm of NO_x.

Environmental Characteristics

Sulfur removal and recovery is an integral part of IGCC and, in fact, is one of the inherent advantages of IGCC over other coal-based electric generating technologies. Direct coal combustion requires removal of sulfur as SO_2 in a dilute flue gas stream at low pressure. The costs for flue gas desulfurization are relatively high, compared to the costs of sulfur removal from coal gases. IGCC, on the other hand, involves the removal of sulfur principally as H_2S plus some COS from the high-pressure, medium-Btu fuel gas produced in the coal gasifiers. The H_2S is removed from the coal gas and then converted to elemental sulfur. This removal and recovery is relatively cheap and extremely efficient. Furthermore, numerous H_2S removal and sulfur recovery processes are commercially used throughout the oil, chemical, and natural gas industries.

IGCC designs all have excellent environmental characteristics compared to other power generation systems, in terms of SO_2, NO_x, and particulate emissions, and solid wastes, and there are solid technical reasons for IGCC's environmental superiority.

Economics of IGCC Systems

The most recent and detailed cost estimates readily available in the literature for commercial IGCC plant designs appear to be the costs developed in EPRI's most recent series of IGCC design studies for the three

Table 3. *Status of Second-Generation Gasification Technologies for IGCC Systems*

Process	*Type*	*Operating Units*	*Date of Operation*
Texaco	*Entrained Flow*	• *Cool Water; 2 x 1000-TPD[a] Coal: 117-MWe IGCC*	*1984*
		• *UBE, Japan; 4 x 500-TPD*	*1984*
		• *Tennessee Eastman; 2 x 900-TPD*	*1983*
		• *Ruhrchemie, Germany; 1 x 800-TPD*	*1986*
Dow	*Entrained Flow*	• *160-MWe IGCC at Plaquemine, LA 2 x 2400-TPD Gasifiers*	*1987*
BGC/Lurgi - Slagging	*Fixed Bed*	• *600-TPD Unit at Westfield, Scotland*	*1986*
Shell	*Entrained Flow*	• *250-TPD Pilot Plant in Texas*	*1987*

[a] *1 TPD = 907 kg/day.*

major systems being developed (Texaco, BGC/Lurgi, and Shell). To facilitate comparative studies of these IGCC designs and different power generation technologies, EPRI has examined the original figures and made certain adjustments to bring all the costs to a common basis expressed in common dollars at a common location.

Performance estimates and costs adjusted to January 1987 dollars are shown in Table 4 for PC plants and the three IGCC designs. These cost estimates indicate that the capital costs for IGCC systems appear to be within the same range as the capital costs for conventional PC plants and for AFBC. Because capital cost estimates, especially for new immature technologies that do not have long commercial histories, are not precise and are often optimistic, this conclusion is the only one that can be drawn from these generic data. In a specific situation utility- and site-specific factors must be considered to determine which technology is more economic. The capital costs for the three IGCC designs show a significant range that is dependent upon gasification technology and design.

Another means of comparing power generation technologies is to compare the cost of the electricity generated. This comparison is usually done via "busbar costing methodology" to compute a levelized cost of electricity (COE) over the life of the plant. The levelized COEs calculated by EPRI are consistently lower for IGCC than for conventional PC under the limited range of assumptions made. However, these differences in the value of the COE between PC and IGCC are not significant and, by themselves, would not be enough incentive for a utility to invest in an IGCC system, which is perceived at this point to be technically risky compared to PC.

One of the advantages of IGCC systems is that they can be highly modular (i.e., contain several parallel trains of gasification and gas turbine components). Therefore, IGCC plants can be constructed in relatively small increments (200 to 250 MW), resulting in the important capability for a utility of conserving capital. The modular characteristic of IGCC systems also leads to high potential equivalent availabilities. This characteristic also leads to capital conservation (by reducing reserve margin requirements) and results in lower revenue requirements as plants can be dispatched at higher capacity factors.

Another advantage of IGCC's modularity is that IGCC can be added in phases of partial capacity to more closely match load growth. There appears to be an economic incentive to add capacity in phases when net present values of expenditures are compared. Phased capacity addition also appears to offer other benefits compared to unphased capacity addition. These benefits include increased flexibility, the ability to recover from sudden and unforeseen changes in load demand, reduction in (and deferral of) "at-risk" capital, and earlier entry of capital into the rate base.

The value of phased capacity addition may be seen by comparing the net present value of capital expenditures for all phases with the net present value of capital expenditures for an unphased plant. In a recent study, the net present value of capital expenditures was calculated for each of three load growth scenarios (5, 7, and 10 years) for adding the capacity of one unphased IGCC plant. Savings due to phased capacity addition ranged between about $200 and $400/kW for these examples.

On the basis of simple comparisons using generic cost and performance data, the economics of IGCC and competing technologies are very comparable, the most economic choice being determined by utility- and site-specific factors. To obtain more detailed information on the effects of these factors on the potential cost-competitiveness of IGCC, the Utility Coal Gasification Association (UCGA) and EPRI are each sponsoring a series of utility-specific studies. The results of these studies should support more definitive conclusions on the economics of IGCC and its acceptability to utilities.

Seven such UCGA studies have been concluded and organized into a report. Six of these studies included IGCC and conventional PC plants among the alternatives considered, and five of the six found phased IGCC to be more attractive economically than conventional PC plants. Three of the five found even unphased IGCC to be more attractive; the other two did not make this comparison. The sixth study concluded that PC was more attractive than unphased IGCC.

Site-specific and cost studies of IGCC show sufficient potential for a number of utilities to begin preliminary planning studies for IGCC (e.g., 18). However, since little additional baseload capacity must be implemented now, many utilities are waiting to see how IGCC and the various gasification technologies continue to develop before seriously considering the technology.

Potential Future Market for IGCC Systems

Projections of the total installed power generation capacity of various types of systems were obtained from base runs of EPA's Advanced Utility Simulation Model (AUSM). According to these projections, made with EPA's interim base case scenario, the total installed capacity for coal-steam plants will increase by 200,000 MW and gas turbine capacity by 57,000 MW from 1990 to 2010.

Table 4. *Summary of Comparative Costs and Performance Estimates for PC and IGCC plants*

Capacity—500 MWe; Illinois #6 Coal; Constant January 1987 Dollars

	Reference Coal-Fired Steam Plant	*Texaco Partial Oxidation*	*Shell Coal Gasification Process*	*BGC/Lurgi Slagging Gasifier*
Sulfur Removal, %	*90*	*95-97*	*90-99*	*95-97*
NO_x Emission, ppmv[a]	*150*	*50-75*	*50-75*	*50-75*
Heat Rate, Btu/kWh[b]	*9,850*	*9,010*	*8,720*	*8,660*
Total Capital, $/kW[c]	*1,390*	*1,540*	*1,490*	*1,300*
Levelized Cost of Electricity at 65% capacity factor, mills/kWh	*54.9*	*52.7*	*50.8*	*48.9*

[a] 15% Excess O_2, Heat Rate Corrected; 1260°C Combustion Turbine for IGCC Plants.
[b] 1 Btu/kWH = 1.055 kJ/kWh.
[c] Includes working capital, start-up costs, spare parts, land, royalties, and allowance for funds used during construction (AFUDC—all IGCC plants rated at 31°C.

The potential application of IGCC systems in this future power generation market will be influenced by a variety of factors, the most important of which may be a satisfactory commercial demonstration of IGCC and IGCC's cost-competitiveness. Utilities must have adequate incentive to accept the technical risk associated with IGCC's lack of a long operating history. The situation that appears to provide the most economic incentive is the concept of phased implementation. As explained above, phased implementation provides a number of benefits in addition to lower overall revenue requirements, and it is possible that IGCC will be implemented initially via this path.

Thus, since phased implementation begins with purchasing combustion turbines initially to provide peaking capacity, it is suggested that the estimated market for gas turbines may provide a clue to the potential initial market for IGCC. The projected market of about 57,000 MW for new gas turbines from 1990 to 2010 should provide significant opportunity for phased IGCC systems. When the cost of natural gas rises sufficiently to make coal-derived gas cost-competitive, gasification systems and steam turbines could be added to form complete IGCC plants. Thus, some of this future peaking capacity could gradually evolve into IGCC baseload capacity that would satisfy part of the anticipated market for new coal/steam plants. Additional opportunities for application of IGCC include repowering of existing coal-fired steam plants and complete IGCC plants that might be built as an unphased capacity addition in competition with conventional PC or other technologies such as atmospheric fluid-bed combustion (AFBC).

Conclusions

The following conclusions were reached as a result of this study:

1. IGCC designs all have excellent environmental characteristics compared to other power generation systems, in terms of SO_2, NO_x, particulate emissions, and solid wastes.

2. The several gasification technologies being developed for IGCC application (Texaco, Shell, BGC/Lurgi, Dow) are in different stages of development with different kinds and amounts of technical risk.

3. The Cool Water plant, a Texaco-based system, is apparently a very successful near-commercial-scale demonstration for Western low-sulfur coal under baseload conditions. Because of various cost constraints, the plant was never designed to compete economically and requires financial guarantees to operate. However, Cool Water data, when extrapolated and analyzed, support the future *potential* of IGCC technologies.

4. Nevertheless, several technical questions remain to be resolved before utilities will embrace even Texaco-based IGCC technology in a significant way, such as:

   —Operability of the Texaco gasifier at full throughput.

   —Materials of construction.

   —Plant operation for at least a year with high-sulfur Eastern coals.

   —Plant availability/reliability

   Only a successful commercial demonstration with advanced technology, operated over a satisfactorily long runtime, can resolve these questions.

5. A number of utilities have conducted preliminary planning studies for IGCC. However, many utilities are waiting to see how IGCC and the various gasification technologies develop before seriously considering the technology. Many feel that oil and gas prices must increase sufficiently relative to that of coal before coal gasification will be economically competitive.

6. Phased implementation may give IGCC significant economic advantages. However, a utility must have access to oil or natural gas to be able to take advantage of phased implementation, and must be prepared to assume the economic risk of increased reliance on natural gas or oil.

7. Simple cost comparisons of IGCC with competing technologies indicate that capital costs may all be within the same range. The higher energy efficiency of IGCC may result in slightly lower levelized costs under a limited range of assumptions.

Recommendations

This technoeconomic appraisal of IGCC power generation led to the following recommendations:

1. Because of the significant work which is currently being done to evaluate IGCC systems, it would be desirable to follow up this current appraisal with periodic updates and analyses.

2. Because utility attitudes, perceptions, and requirements are of paramount importance in determining the potential implementation of IGCC, it would be desirable that more extensive discussions be held with utilities regarding IGCC.

3. It is also desirable that the potential role of IGCC in repowering be examined in detail. However, site-specific conditions are particularly important, and studies being conducted by EPRI could be an important future source of information regarding the repowering potential of IGCC.

4. Since phased implementation is an important concept affecting the potential employment of IGCC, it would be desirable to incorporate phased implementation into EPA utility models.

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The complete report, entitled "Technoeconomic Appraisal of Integrated Gasification Combined-Cycle Power Generation," (Order No. PB 90-272 071/AS; Cost: $23.00, subject to change) will be available only from:

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