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Coal Combined Cycle System Study

Volume I—Summary

Project Team

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ABSTRACT

The potential advantages for proceeding with demonstration of coal-fueled combined cycle power plants through retrofit of a few existing utility steam plants have been evaluated. Two combined cycle concepts were considered: Pressurized Fluidized Bed (PFB) combined cycle and gasification combined cycle. These concepts were compared with AFB steam plants, conventional steam plants with Flue Gas Desulfurization (FGD), and refueling such as with coal-oil mixtures. The ultimate targets are both new plants and conversion of existing plants. Combined cycle plants were found to be most competitive with conventional coal plants and offered lower air emissions and less adverse environmental impact. A demonstration is a necessary step toward commercialization.

FOREWORD

The MITRE Corporation is under contract to the Office of Coal Utilization, Fossil Energy, U. S. Department of Energy, to provide systems engineering, integration and analysis under Contract No. ET-78-C-01-3189. This document was performed as a part of Task Order No. 401-002, at the request of Mr. Winfred M. Crim, Director, and Warren W. Bunker, Project Manager, Heat Engines and Heat Recovery Division.

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EXECUTIVE SUMMARY

The research and development programs of DOE's Office of Coal Utilization have focused on two coal-based combined cycle power technologies: the pressurized fluidized-bed system (PFB) and the integrated coal gasification system (GCC). Both of these technologies have the potential for competitive efficiencies plus the ability to remove sulfur at an early stage in the process, thus avoiding the need for flue gas desulfurization. Each of these technologies has reached a stage of development that requires a decision on whether to build commercial-sized demonstration facilities. The demonstration program could involve the repowering* of existing power plants, assuming technical feasibility, or the construction of new plants. In addition, there are technical alternatives to coal combined cycles such as new coal-fired conventional steam plants, coal-oil mixture (COM) combustion in existing plants, and atmospheric fluidized-bed (AFB) boilers for new or existing plants. These alternatives were evaluated and compared with coal combined cycle concepts in the study.

The MITRE Corporation has assembled and analyzed the technical issues pertaining to the coal combined cycles needed as inputs to the decision making process. A substantial national inventory of

*Repowering: The conversion of a plant to increase net output; for example, the addition of a combustion turbine to an existing steam plant in the form of a topping cycle.

oil- and gas-fired power plants exists. Most of these plants have a remaining service life of more than 20 years, but their dependence on high-cost fuels will relegate them to peaking or standby duty. These plants are promising candidates for refueling* with a coal-based technology. The most significant constraint to refueling is land availability.

Existing plants that have virtually no adjacent land could be converted to COM combustion. However, since COM's marginal cost of electricity is greater than coal or nuclear plants, it would be relegated to low usage to the extent that lower cost power from nuclear, hydro or coal plants would be available. If land were available a few miles away from the existing plant, a coal gasification facility could be built to supply that power plant with medium-Btu fuel gas.

If land adjacent to the existing plant is available, the options for conversion to coal-based technology increase. The existing boiler could be converted to coal combustion or a new boiler constructed. Converting an existing oil-designed boiler to coal could require a derating amounting to as much as 40 percent. Use of COM is expected to require less derating. A DOE program is being initiated to determine such derating. A new boiler could be conventional pulverized-coal or AFB. If the utility needed more power, the

*Refueling: The conversion of a plant to another fuel; for example, the change from oil to COM, or the reconstruction of an oil-fired boiler to burn coal.

existing plant could be repowered into a gasification or PFB combined cycle.

The COM option is the only alternative that would probably not be considered for a new power plant at a new site because the primary objective of COM technology is refueling through conversion of existing plants. All of the others are genuine competitors.

As a general representation of the utility opportunity, the refueling of existing oil- and gas-fired steam plants offers a sizeable market, approximately 78 and 50 Gigawatts, respectively. Some repowering of existing plants may be of interest to utilities. In addition, the general growth in electricity demand will require around 83 Gigawatts between 1988 and 2000. Finally, a substantial market will open after 1988 as worn-out plants are replaced and new plants are built to meet growth in electric demand. This market could amount to 54 Gigawatts during the 1988-2000 period. The crucial factors for decision making on power plant concept will include technology, finance, and environmental impact. This market opportunity is summarized in Figure A.

Any new power plant technology will require successful demonstration before it will be given serious consideration by the utilities. The attributes to be demonstrated include capital and operating costs, environmental compliance, resource requirements, reliability, maintainability, and acceptability to regulatory bodies. Of critical importance is whether the plants' builders and suppliers

FIGURE A
COAL COMBINED CYCLE SYSTEM STUDY SUMMARY

will offer suitable warranties on the equipment and on the plant as a whole.

Current estimates of capital and operating costs are insufficient in accuracy to substantiate the selection of any concept. In perspective, the spread in construction costs of similar plants using current pulverized-coal technology can exceed 15 percent due to construction vagaries and site variations. The coal combined cycle concepts and some alternative concepts fall within this band. Technology improvements could yield benefits for each concept. For example, improved gasification techniques and increased turbine firing temperatures could yield significant performance and cost improvements for the gasification combined cycle (GCC).

The comparison of environmental impacts yielded the largest apparent difference among the competing technologies. The PFB combined cycles appear to offer the potential for up to 70-percent reduction of both SO_2 and NO_x emissions relative to the pulverized-coal steam plant with conventional FGD. The gasification combined cycle appears to offer more than 95-percent reduction of these pollutants plus exceptionally low particulate emissions. The low water consumption of GCC is also noteworthy. It must be noted, however, that the potential emission advantages of PFB and GCC power plants are based mainly on manufacturer projections from experimental units. The actual emissions from these power plants must be proven in full-sized demonstration units.

These predictions yield the conclusion that coal combined cycles have the strong potential for a significant future market position. More definitive data is required that can only be achieved through demonstration in a prototype installation. The general program steps are illustrated in Figure A. Either conversion of existing plants or construction of new facilities would achieve this objective. There appears to be no technical difference between the conversion of an existing steam plant or construction of a new plant for utility acceptance of the demonstration results. Conversion of existing facilities could save money and time, depending on the specific site situation. Whatever demonstration is performed should be closely tied to the regions expected to have the greatest future need for the demonstrated technologies. Regardless of demonstration techniques, the market "pull" for plants operating on coal-based or other low-cost fuels is sufficiently strong to warrant intense effort on accelerating introduction of technologies that offer potentially lower environmental problems and lower cost of electricity while reducing the national dependence on imported oil.

INTRODUCTION

The research and development program of the Office of Coal Utilization, U.S. Department of Energy, has included advanced technologies for the generation of electricity from coal through the use of combined cycles of steam turbine and gas turbine. The focus has been on two technologies: one in which the pressurized, elevated-temperature combustion gases are generated by the combustion of coal in a fluidized bed; and the other in which these gases are produced by the combustion of fuel gases derived from a prior gasification of the coal. Both technologies offer the facility to remove the sulfur content of the coal at an early stage to avoid the need for complex downstream flue gas desulfurization equipment.

For each combined-cycle technology, development has reached a stage where a decision on constructing and operating demonstration facilities must be made. Assembly and analysis of the technical issues and data are required as an input to the decision making process on whether to proceed with these demonstration projects. The MITRE Corporation was requested by DOE to perform a technical evaluation study on this subject. The technical topics covered in this study and presented in this report include: the market potential for combined cycle technology; the status of technology development; the economics of combined cycle concepts compared with current and other advanced power plant concepts; a comparison of environmental factors; and an overall assessment of the benefits of demonstrations of combined cycle system technologies to the national interest.

Purpose and Scope

The purpose of this report is to present information and data with the overall objective of determining whether a DOE-sponsored demonstration program focused on conversion of one or more existing steam plants is an effective strategy for introducing the coal-fueled combined cycle into the U.S. electric utility sector. This objective requires achievement of the following limited objectives:

Market Potential. To provide an estimate of the opportunity for new or converted plants which is amenable to the use of coal-based combined cycle technology through both new construction and the re-powering* of existing installations.

Technology Status. To provide for each technology (fluidized-bed combustion and gasification) a status of technical risk in terms of unresolved issues or unsolved problems and current research and development activity addressing the issues and problems for use in the DOE decision to proceed with the demonstrations.

Economic Analysis. To compare the costs of generating electricity for base loads using coal-based systems in two situations: (1) expansion of generating capability; and (2) conversion of existing oil and gas plants to coal operation.

Environmental Assessment. To assemble a meaningful comparison of the environmental impacts of coal-fueled power plants.

*Repowering: The conversion of a plant to increase net output; for example, the addition of a combustion turbine to an existing steam plant in the form of a topping cycle.

Program Approach. To determine the worth of proceeding with conversions of existing steam plants to demonstrate attributes of the combined cycle system.

Achievement of the above objectives will provide a basis for assessing a decision to proceed with demonstration projects. Total justification for the expenditure would include aspects beyond the scope of this report, such as political factors, the national defense and economic independence aspects of reducing oil consumption, and government policy regarding cost sharing with industry/utility combines, which can affect the feasibility of undertaking demonstration projects.

Study Approach

The approach employed recognizes the sensitivity of the results, particularly the extent to which reduced costs will increase market penetration. A major technology-dependent variable impacting cost is turbine inlet temperature of the gas turbine unit. Combined cycle technology, particularly that based on coal gasification, is in development. The current technology allows a maximum turbine inlet temperature of around 2000°F with clean gas. The expectation for the long term (year 1990-2000) is a turbine capability of 2600-3000°F firing temperature.

Market penetrations have not been estimated in this study. Such an analysis, if performed, would recognize that the competitive technological alternatives to combined cycle concepts (whether by

coal gasification or the pressurized fluidized-bed combustion of coal) are different, depending on whether the subject is: (a) the market for conversion of existing installations to use coal; or (b) the market for redesign of planned new capacity still in the design stage. In lieu of a market penetration analysis, a market opportunity has been estimated for the 1988-2000 period.

The technological alternatives to combined cycle in the plant conversion market are the use of coal-oil mixture combustion and the replacement of the boiler by new coal-fired boilers. In the near-term market where the designs have not been started into construction, the alternatives are the generation of the steam by pulverized-coal boiler with flue gas desulfurization and by atmospheric fluid-bed combustion.

The major criteria used in the evaluation of alternative concepts are the following: environment, economics and technology. Environmental concerns have received extensive national attention. Economics involves both capital cost outlays as well as least cost of electricity. Technology covers program risks and decisions on whether to continue improving component technology or to initiate full-scale demonstrations of the system concept. Any system considered for implementation must score favorably on all of these criteria.

The study has been performed through the review of published technical data on each of the candidate power plant concepts.

Additional technical data have been provided through informal communication with the Electric Power Research Institute (EPRI) and potential suppliers of major components. Methodologies have been developed for assimilating the technical data on economics and environmental impact into a common basis for quantitative comparison.

The general comparisons and other results of the study are presented in Volume II. A complete compilation of technical data for each candidate power system is presented in Volume III.

MARKET POTENTIAL

Opportunity Analysis

The national growth in the demand for electricity (average load) assumed in this study is listed below. These projections were extracted from a recent DOE econometric model as a "best estimate" case.*

<u>Period</u>	<u>Annual Growth</u>
1978 - 1985	3.9%
1985 - 1990	3.6%
1990 - 1995	1.8%
<u>1995 - 2000</u>	<u>0.5%</u>
1978 - 2000	2.6%

The expected distribution of growth by NERC region (Figure 1) in the demand for electricity (average load) for the period 1978-2000 was estimated using a combination of DOE/EIA and NERC projections.** These results are as follows:

<u>NERC Region</u>	<u>Annual Growth</u>
ECAR	2.5%
ERCOT	2.5%
MAAC	1.8%
MAIN	2.5%
MARCA	2.9%
NPCC	1.8%
SERC	2.9%
SPP	3.4%
<u>WSCC</u>	<u>2.5%</u>
NERC	2.6%

*Source: DOE, "Policy and Fiscal Guidance Energy Projections, Appendix D," February 1980.

**Source: Scaled from data contained in "1979 Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirements," National Electric Reliability Council, July 1979.

FIGURE 1
REGIONAL RELIABILITY COUNCILS
OF THE NATIONAL ELECTRIC RELIABILITY COUNCIL

The expected electricity production characteristics for 1988 (summer peak) are presented below by NERC region. This estimate assumes that nuclear capability does not exceed 120 gigawatts. (This assumes no nuclear additions after 1984). In addition, approximately 20 gigawatts of existing oil-fired plants that were originally designed for coal are assumed to be converted back to coal prior to 1988. These data form the basis for estimate of additions required after 1988.

TABLE 1
PROJECTED INSTALLED GENERATING CAPABILITY, SUMMER 1988
(Gigawatts)

<u>Region</u>	<u>Total</u>	<u>Less Oil</u>	<u>Less Oil & Gas</u>
ECAR	124	119	119
ERCOT	55	55	27
MAAC	55	46	46
MAIN	59	55	55
MARCA	32	32	32
NPCC	56	42	42
SERC	162	148	148
SPP	79	71	50
<u>WSCC</u>	<u>136</u>	<u>112</u>	<u>110</u>
NERC	758	680	629

Based on an annual growth rate of 2.6 percent from 1978 to 2000, the total installed generating requirement, assuming complete backout of both oil and natural gas, is on the order of 894 gigawatts by 2000 of which 265 gigawatts (including replacements) will need to be installed during the 1988-2000 period. This estimate assumes retirement of existing steam plants at an average plant age of 45 years. The conversion of any existing oil and gas fueled plants is counted in this estimate as new capacity. Figure 2 shows a sample schedule

of additions which is levelized over the 1988-2000 period. Section 2.1 of Volume II contains a detailed presentation of these additions presented below:

TABLE 2
REGIONAL ALLOCATION OF PROJECTED ADDITIONS
(Gigawatts)

<u>Region</u>	<u>Additions</u>
ECAR	24
ERCOT	32
MAAC	15
MAIN	14
MARCA	7
NPCC	30
SERC	51
SPP	34
WSCC	<u>58</u>
NERC	265

Some additions could be achieved through conversion of existing (as of 1988) oil- and gas-fired steam plants. These projections are presented below by region:

TABLE 3
PLANT CONVERSION POTENTIAL
(Gigawatts)

<u>Region</u>	<u>Oil to Coal Conversions</u>	<u>Gas to Coal Conversions</u>
ECAR	5	0
ERCOT	0	28
MAAC	9	0
MAIN	4	0
MARCA	0	0
NPCC	14	0
SERC	14	0
SPP	8	21
WSCC	<u>24</u>	<u>2</u>
NERC	78	51

FIGURE 2
LEVELIZED SCHEDULE OF NEW PLANTS BY
STARTUP DATE SATISFYING PROJECTED LOAD

For illustrative purposes, five of the NERC regions (ERCOT, MAAC, NPCC, SPP and WSCC) have sufficient installed capacity in oil- and gas-fired steam plants to meet the projected demand for the year 2000 through repowering. Assuming technical and economical feasibility, retrofit of these plants with appropriate elements for coal utilization could come close to complete backing out both gas and oil from electric utilities. An average 50-percent increase in the aggregate power output for existing oil- and gas-fired steam plants in all NERC regions would eliminate approximately 65 percent of the requirement for new plants. However, this study has not been performed in sufficient detail to determine the technical and economic feasibility of this amount of increased power through repowering. Thus, the choice for most utilities is whether to build new plants, convert existing plants, or a combination thereof. Further study is required to determine the feasible range of the split between new plants and conversions of existing plant. However, the potential market opportunity for coal combined cycle power plants through the 1990s is substantial.

Utility Survey

The MITRE Corporation was requested by DOE to solicit opinions from the electric utility industry to determine the total benefits if DOE initiated demonstration programs for advanced coal utilization projects. Of specific interest were the advanced coal combined

cycles employing the PFB and the coal gasification concepts. Seven utilities were subsequently selected and interviewed.

It was determined that the utilities considered demonstration plants essential before new technologies could be considered in their systems. They further felt that manufacturers would not be able to establish firm prices and warranty risks without the benefits of demonstration plants. An additional general feeling was that the federal government's participation in demonstration plant projects is essential because of the large amount of funding required, which probably would not be available from private industry.

Utilities are quite interested in new power plants able to burn coal in an environmentally acceptable manner. Utilities visited currently have large amounts of peak power reserves, considerable amount of firm power additions for this decade, and load growths considerably below expectations. As a result, they expect to enter 1990 with considerable peak power reserves, a situation applicable to many utilities.

Additional new power plants are not expected to be required until mid-1990s. With the current 10-year approval and construction cycle, new power plant planning is anticipated to begin in mid-1980s. Demonstration plant results must be available at that time for new technologies to be considered in new power plant planning.

Many plant conversion opportunities might exist because utilities are working to meet the 1990 deadline for reductions of natural

gas and oil fuels, independent of peak power reserves. Although repowering plants qualify as new and must go through the regulatory cycle, the cycle might be shorter for an existing site. If successful demonstration plant results are available in mid-1980, utilities expect that these technologies could be considered for repowering. They caution, however, that some of the potential repowering plants do not have adequate space for the addition of coal facilities.

Regarding age of potential repowering candidates, it had initially been expected that primary utility interest would be directed toward older oil-fired installations. Incentives perceived were the use of coal at a lower fuel cost and at improved heat rate. However, many utilities tended to consider the repowering option more in terms of their newest oil-fired plants. These plants have a high book value. Utilities have a strong incentive to convert them to coal fuel. The alternative after 1990 might be to use them only for peaking power. It is perceived that these new or relatively new oil-fired steam plants could well be a very important market for advanced coal utilization technologies.

For both repowering and new plants targeted for the mid-1990s, successful demonstration plant test results must be available by about 1985.

Utilities agree that a utility advisory panel on demonstration plants will hasten commercialization by keeping them advised of demonstration plant progress.

TECHNOLOGY STATUS

This section summarizes for each of the two combined cycles the unresolved issues and unsolved problems and the current progress underway to resolve issues and solve problems.

1. PFB Systems

a. Technology Background and Data Base

- Early and extensive experience through the present time was gained from the Fluidized Bed Catalytic Cracker widely used in the oil refinery industry. Experience includes both fluidized beds and often associated expansion turbines. Also, there has been extensive experience with fluidized beds using lime calciners and ore roasters.
- Extensive experience with a Steam-Tube-Cooled PFB firing coal has been achieved with the Process Development Unit (PDU) operated by Coal Utilization Research Laboratories (CURL) at Leatherhead in the U. K., operating at up to about 1.3 MWe equivalent. A 1000-hour test run has recently been completed with two cascade and cleanup systems operated in parallel, with favorable results.
- The most significant U. S. Steam-Tube-Cooled PFB experience has been with the Exxon Miniplant, which is approximately half the size of the CURL plant. This installation has also recently completed a 1000-hour run testing steam tube materials and a turbine blading cascade. Results are being evaluated.
- Curtiss-Wright has substantial test experience with an Air-Tube-Cooled PFB operating at approximately 0.06 MWe equivalent. A 1000-hour test with this combustor has recently been completed, with favorable results.
- Combustion Power Corporation has significant test experience with an adiabatically cooled PFB operated at approximately 1.3 MWe equivalent.
- PFB process data have been obtained from smaller scale test units at Argonne National Laboratory and NASA Lewis.

b. Current PFB Systems Programs

(1) Steam Tube Cooled PFB

- American Electric Power (AEP) and Stal-Laval (Sweden) are progressing on the design of a 170-MW PFB demonstration plant to be installed in the AEP Tidd (Ohio) Power Plant in the mid-1980s.
- In preparation for the AEP power plant, Stal-Laval is building a subscale test facility which will be a 1/18-sector of the commercial size bed in Sweden (10 MWe equivalent).
- International Energy Agency (IEA) is progressing with a nominal 34-MWe equivalent flexible test facility in Grimethorpe, U. K.
- General Electric is progressing with a DOE sponsored nominal 580-MW multiple module PFB Steam-Tube-Cooled commercial power plant design.

(2) Air Tube Cooled PFB

- Curtiss-Wright is proceeding with a nominal 13.6 MWe equivalent pilot plant in their Wood-Ridge, New Jersey facility.
- Curtiss-Wright is progressing with a 500-MW Air-Tube-Cooled multiple module commercial power plant design

c. Technology Gaps

(1) Bed Scaleup - includes bed geometry, coal and dolomite feed provisions, ash and spent sorbent removal provisions, associated hardware and plumbing.

- American Electric Power and Stal-Laval (AEP/SL) hope to minimize problems with a commercial-size system by testing a 1/18-sector of the full-size installation with all associated hardware.
- Curtiss-Wright plans to use the Small Gas Turbine (SGT) PFB air heater elements as modules for their pilot plant equipment and subsequently for their commercial-size plant.

- IEA Grimethorpe is primarily scaling the CURL Leatherhead design and test data.
 - Successful ability to scaleup all hardware to commercial plant size has yet to be demonstrated.
- (2) Gas Cleanup - includes primarily particulates and vapor phase alkali compounds. Sulfur and nitrogen compounds are not expected to cause cleanup problems for PFB systems.
- Conventional inertial cleanup devices (cyclones) can remove most large particulates known to be damaging to turbine bladepaths. While there does not appear to be a turbine manufacturer consensus, Stal-Laval, for example, believes that they have a satisfactory trade-off between turbine blade life and replacement costs versus the costs of additional cleanup stages.
 - Particulate removal from PFB test rigs, however, has not been shown to be sufficient to meet EPA New Source Performance Standards requirements. Additional downstream cleanup devices, such as baghouses or precipitators, would be required with current hot cleanup of particulate technology.
 - Since alkali compounds are in the vapor phase, they are not removed by inertial cleanup devices and will pass through to the turbine. The extent to which this is a problem depends upon a number of factors, including blade metal temperatures and materials or claddings, as discussed below under Turbine Tolerance.
 - DOE has recently selected five companies to develop hot cleanup systems for the reduction of particulates and alkali compound vapors before passing through to the gas turbine, but it is too early in the effort for results.

(3) Turbine Tolerance - includes resistance to gas turbine erosion and corrosion from particulates and alkali vapors.

- Turbine manufacturers generally have been engaged in programs to develop coatings and claddings which are resistant to corrosion from alkali compounds. Initial results are quite encouraging.
- Combinations of modest turbine inlet temperatures (1400°F to 1550°F) and protective blade coatings or claddings appear to give adequate protection up to 1000 hours from tests to date.
- The life of such blading protective coverings is not known. Corrosion is recognized to have a variable incubation period, prior to a slow parabolic attack period, and then a rapid linear attack period, if corrosion is going to be blade-life limiting. Testing periods have been too limited to determine how resistant present coatings are under real conditions or actual operation periods.
- Blade cascade tests with the various PFB PDU test units have shown little tendency toward serious blading erosion or deposition. However, testing periods, again, have been too limited for conclusive results.
- Coatings and claddings developed for corrosion resistance have generally exhibited increased resistance to particulate erosion.
- Any significant success with cleanup system developments, particularly suppression of alkali compounds, would obviously benefit gas turbine tolerances.
- Long-term operation in full-scale rotating machinery in PFB atmospheres will be necessary to judge the overall success of blade coating and cladding developments.

2. Gasification Systems*

a. Technology Background and Data Base**

(1) Fixed or Moving Bed Gasifiers

- The dry-ash, oxygen-blown Lurgi has extensive world-wide experience over many years as a fully commercialized coal gasifier and has been used primarily for chemical feedstocks and other high-Btu uses.
- An advanced, stirred gasifier was first developed at the Morgantown (West Virginia) Energy Research Center (METC), and became the basis for the General Electric GEGAS advanced fixed bed gasification facility, Schenectady, New York. Both facilities are about one T/hr and are air blown; however, the METC gasifier can also be oxygen blown. These gasifiers are R&D units.
- A slagging oxygen-blown Lurgi has been under development at the Westfield Research Center, Westfield, Scotland. This British Gas concept development work was sponsored by a number of U.S. companies headed by CONOCO on a 35 MW_e equivalent Lurgi. Results are encouraging and throughput has been increased by as much as a factor of three over the modern conventional Lurgi.
- Air blown conventional Lurgis have been operated in a 170-MW combined cycle, starting in about 1970 in Lünen, F.R.G. This demonstration unit was successful, but operation was not economical and the plant was shut down in 1977.
- A 26 MW_e equivalent pressurized, slagging, oxygen-blown gasifier developed earlier by the Grand Forks (N.D.) Energy Research Center has

*A 100-MW combined cycle power plant requires a nominal 1000 ton/day coal gasification system.

**Gasifiers are of primary interest to the data base, regardless of whether the intended end use is for petro chemical or electric power application.

been under test since 1976. This is an R&D unit.

(2) Entrained-Flow Gasifiers*

- The oxygen-blown Texaco entrained-flow gasification process was developed in a nominal 1.7 MW_e equivalent pilot plant at the research facilities in Montebello, California. A 17 MW_e equivalent facility in Oberhausen, F.R.G., confirmed the success of a tenfold scaleup of the pilot plant.
- Late in the 1950s, an oxygen-blown, slagging, entrained-flow gasifier of Babcock and Wilcox design was operated at what is now the Morgantown Energy Technology Center at 300 psig and 1.3 MW_e equivalent capacity. Results of this and other tests were used in the design of the 13 MW_e equivalent Bi-Gas pilot plant at Homer City, Pennsylvania.
- Atmospheric entrained flow coal gasifiers such as the Combustion Engineering and numerous Koppers-Totzek gasifiers have contributed to the entrained flow coal gasifier technology.

(3) Fluidized-Bed Gasifiers*

- Westinghouse has developed a pressurized 1.7 MW_e equivalent pilot coal gasification plant reportedly suitable for single or two-stage operation and which can be air or oxygen blown.
- A two-stage fluidized-bed coal gasification plant using the CO₂ acceptor process was tested in a 3.3 MW_e equivalent pilot plant at Rapid City, South Dakota, by CONOCO under contract to DOE. It is now shut down.

*Gasifier R&D has been primarily for fuel gas, pipeline gas, and petrochemical feedstocks. The majority of gasifiers reflect this. Entrained flow and fluidized-bed gasifiers are also well suited for the coal combined cycles.

- A fluidized bed gasifier was operated in an 8 MW_e equivalent Synthane process plant at Bruceton, Pennsylvania, in a development by Pittsburgh Energy Technology Center (PETC) until 1979.
- A three-stage fluidized-bed hydrogasifier has been tested at an 8 MW_e equivalent installation at the Institute of Gas Technology, sponsored by American Gas Association (AGA) and the Office of Coal Research (now DOE). The overall process is known as HYGAS and is still under test.
- A single-stage fluidized-bed gasifier is being tested in a 2.7 MW_e equivalent U-Gas process at the Institute of Gas Technology.
- A pressurized 0.8 MW_e equivalent fast fluidized two-stage bed suitable for air or oxygen blown operation has been under test by Hydrocarbon Research, Inc. (HRI) at Lawrenceville, N.J.

b. Current Programs

(1) Fixed-Bed Gasifiers

- While the conventional Lurgi is the preferred gasifier for six or more proposed commercial high-Btu coal gasification plants, no such plants are under construction at this time.
- The British Gas slagging gasifier tests at Westfield, Scotland, are continuing under the sponsorship of 15 North American companies.

(2) Entrained-Flow Gasifiers

- The 100-MW Southern California Edison Cool Water combined cycle power plant with a 1000-T/D Texaco entrained flow coal gasification plant is now undergoing financing and is expected to proceed toward plant startup in late 1983.
- The Tennessee Valley Authority is installing a 17 MW_e equivalent Texaco gasifier to generate feed gas to replace natural gas in its Muscle Shoals, Alabama, ammonia plant.

- Tennessee Eastman will begin construction of a plant to make acetic anhydride from coal using the Texaco gasification process, understood to be about 1600 T/D.
- A single stage pressurized gasifier developed by Shell and Krupp-Koppers is being tested at Shell's Hamburg, Germany refinery.

(3) Fluidized-Bed Gasifiers

- A 6.7 MW_e equivalent pilot plant is under construction by Enrecon, Inc.
- Exxon has a nominal 2.7 MW_e equivalent pressurized, fluidized bed catalytic process under test in Baytown, Texas.

(4) Other Coal Gasification Systems

- An Allis-Chalmers KILNGAS 67 MW_e equivalent demonstration plant has been approved to start construction in East Alton, Illinois. This gasification concept is based on rotary kiln designs produced by A-C for high temperature bulk solids processing.
- A Rockwell International Company Rockgas 2.7 MW_e equivalent PDU has been built at Santa Susanna, California, and it is understood that testing is now in process. Rockgas is the Rockwell sodium carbonate molten salt coal gasification process.

c. Technology Gaps

- (1) Gasifier Scaleup - The various gasifiers are in different stages of maturity; hence, the scaleup considerations are different.
 - The conventional oxygen-blown Lurgi gasifier is fully commercialized in 9-foot and 12-foot diameter sizes.
 - The slagging oxygen-blown Lurgi has been demonstrated in the 9-foot diameter gasifier. Scaleup to a 12-foot diameter gasifier is not believed to present great difficulty.

- The Texaco entrained flow gasifier has been successfully scaled-up from 15 T/D to 150 T/D. The present scaleup to 1000-T/D coal feed rate is not expected to be difficult.
 - Fluidized-bed gasifiers have only been tested in PDU size. These gasifiers have shown great promise, but should be operated in pilot plant sizes before scaleup to commercial sizes.
 - The KILNGAS demonstrator plant size of 67 MW_e equivalent coal input is approximately commercial size. If its operation is successful, no scaleup problems are visualized.
 - The Rockwell and Exxon benchscale gasifiers are considered to be in too early a stage of development to estimate scaleup difficulties.
- (2) Gas Cleanup - Cold cleanup systems have been almost universally included or proposed with all gasification systems. No difficulties with turbine tolerance or environmental constraints are visualized, and potential problem areas are considered to be more in the cleanup system itself with the high temperature effluent gasifiers. High temperature heat exchangers required have yet to be developed.
- The fixed-bed gasifiers have an effluent temperature of approximately 1000°F. This must be quench-cooled by direct water contact for the removal of tars down to the nominal 350°F temperature level. This can result in sensible heat losses, but has been accepted in practice where efficiency was of secondary concern.
 - The entrained-flow and fluidized-bed gasifier effluents are not expected to contain tars, but will have high effluent temperatures on the order of 1800°F to 2500°F. The effluents will contain particulates, but more seriously will contain alkali compounds in the vapor phase.
 - These effluents can also be quench-cooled to the 1000°F to 1200°F temperature range to minimize vaporized alkali compounds, but this would represent significant sensible heat losses.

- It is understood that some manufacturers plan to use a waste heat boiler for initial raw gas cooling since the boiler metal temperature levels will be low. This can be followed by recuperative heat exchange of raw fuel gas against clean fuel gas. The remaining questions concern deposition and ease of removal in the waste heat boiler section.
- (3) Turbine Developments - Include the gas turbine combustor and turbine blade path sections.
- Oxygen-blown gasifiers producing medium-Btu fuel gas will have very high stoichiometric flame temperatures compared to low-Btu fuel gas or even natural gas and fuel oil. This will tend to greatly promote the production of thermal oxides of nitrogen. This can be alleviated by injection of steam or water into the combustor, but the amount of water consumption would not be expected to be acceptable in most sections of the country.
 - Dry control of nitrogen oxides has been proposed by the use of fuel/air premixing, staged combustion and catalytic combustion. These developments are promising, but remain to be demonstrated on full-size, baseload gas turbines.
 - The full potential advantages of the coal gasification combined cycle will not be realized until gas turbine firing temperatures are raised. Advanced cooling systems can be incorporated in the gas turbine stationary blading with acceptable difficulty, but advanced systems for rotor blade cooling will be more difficult to realize.
 - It is believed that advanced blade cooling for the stationary blading will result from industry efforts to obtain some increases of firing temperatures. Subsequent advanced cooling of the rotating blading may be dependent upon the success of projects such as the DOE High Temperature Turbine Technology Program.

ECONOMIC ANALYSIS

The life cycle cost of electricity (COE) for the two combined cycle technologies was calculated and compared with that of several other competing technologies. For each technology, costs were calculated for one or both of two system implementation concepts: new plant systems and conversions of existing systems. The COE for the conversion concepts (i.e., repowering) are lower than new systems since existing facilities are used and therefore capital costs are lower.

The financial parameters used to calculate the COEs are presented in Table 4. A 6-percent general inflation was assumed as applicable for the next two decades. All costs were escalated at the general inflation rate except construction cost (8 percent) and residual oil (10.3 percent) costs. The assumption of a higher general inflation would change the estimated COE, but not necessarily the comparative relationship of the alternatives.

The technologies analyzed will be used by utilities to either expand capacity to satisfy growing demand or to repower existing systems to permit the utility to decrease its reliance on oil. For purposes of this comparison, it is assumed that capacity expansion will be obtained using new systems. Therefore, a comparison of the new system COEs would indicate how the technologies might compete economically for the capacity expansion market. Conversion (or repowering) decisions which decrease reliance on oil are more

TABLE 4

ASSUMED FINANCIAL PARAMETERS FOR ECONOMIC ANALYSIS

Price Increases per Year

General	6%
Construction Cost	8%
Operating & Maintenance	6%
Fuel	
Coal	6%
Residual Oil	10.3%

Cost of Capital

Real Interest Rate on Debt	3%
Real Interest Rate on Equity	9.5%
Debt/Equity Ratio	50/50

Taxes

Income Tax Rate	50%
Property Taxes & Insurance	3%
Investment Tax Credit	10%

Depreciation Schedule

Sum of year's digits
over 2/3 of plant life
with no salvage value

Fuel Costs (\$/mm Btu in 1979 \$)

Coal	1.30
Residual Oil	3.54 - 3.70

Construction Time

New Plants	3.33 yr
Plant Conversions	3.33 yr
COM Conversions	1.0 yr

appropriately analyzed as replacement decisions. As a result, the life cycle cost of electricity from conversions should be compared with the "do nothing" alternative, i.e., continue use of oil in an existing oil-fired facility.

The COE estimates were developed using a methodology derived by EPRI and used by the DOE commercialization Task Force.* COE estimates as a function of year of initial operation were calculated for the 15 systems shown in Table 5 using the capital cost and efficiency data presented in Tables 6 and 7. These tables indicate considerable ranges of estimates due to the variations assumed by different designers and cost estimators.

The results of the analysis are presented in Figures 3 and 4. Figure 3 shows the relative life cycle COE for new facilities starting operation in 1990. The year 1990 was selected since, based upon the market analysis, this is a reasonable time frame for utilities to need facilities to satisfy capacity expansion requirements. The ranges on the COE estimates indicate the range of technical designs and economic data used in the system designs reviewed to develop the cost data for the economic analysis. They do not include uncertainty associated with the cost of technologies which have not been used commercially. For example, the relatively large range for

* - A life cycle costing methodology developed by DOE/PE which is based upon a similar methodology and produces similar results was also considered. However, for the purposes of this study effort, the EPRI method was selected since it was more convenient.

TABLE 5
ELECTRIC GENERATING SYSTEMS CONSIDERED

TECHNOLOGY	System Characteristics		
	<u>New</u>	<u>Conversion</u>	<u>Notes</u>
Conventional Pulverized Coal ⁽¹⁾			
Current FGD	X	X	
Advanced FGD	X	X	
Fluidized Bed			
Atmospheric (AFB)	X	X	Retain Steam
Pressurized (PFB)	X	X	Turbine/Generator
			and Related
			Facilities
Combined Cycle Gasification ⁽²⁾			
Current Turbines (2000°F)	X	X	
Advanced Turbines (2600°F)	X	X	
Refuel Existing Facilities ⁽³⁾			
Coal-Oil Mixture		X	Retain Steam
Coal-Derived Liquids		X	Boiler, Steam
Low- and Medium-Btu Gas		X	Turbine/Generator
			and Related
			Facilities

- Notes: (1) The conventional pulverized-coal steam plant constitutes a mature technology. However, Flue Gas Desulfurization (FGD) is a developing technology. Current FGDs use lime or limestone scrubbers. Advanced FGDs use regenerable chemicals. Lower plant efficiency is expected with advanced FGDs.
- (2) Two levels of technology are assumed for the gas turbine in Combined Cycle Gasification: 2000°F for current technology, and 2600-3000°F for advanced technology. No differentiation is made on coal gasifier technologies in this analysis.
- (3) Facilities for refueling existing steam plants can be located on site or off site. Also, these facilities could be owned by the utility or a supplier of fuel. This economic study assumes the utility owns these facilities.

TABLE 6
CAPITAL COSTS FOR NEW SYSTEMS - 1990 STARTUP
(1979 dollars)

Technology	Total Erected Costs (\$/kW)	Efficiency (percent)	Capacity (MW)
Conventional Pulverized Coal			
Current FGD	955-1222	34.0-35.0	700
Advanced FGD	1046-1358	31.5-32.5	700
Fluidized Bed			
Atmospheric (AFB)	777-1208	34.0-35.0	700
Pressurized (PFB)	1187-2013	39.5-40.5	700
Combined Cycle Gasification			
Current Turbines	1156-1829	35.8-37.1	700
Advanced Turbines	1044-1618	40.6-38.7	700
Refuel Existing Facilities			
Coal-Oil Mixture	---	---	---
Coal-Derived Liquids	---	---	---
Low & Medium Btu Gas	---	---	---

TABLE 7
CAPITAL COSTS FOR CONVERSION SYSTEMS - 1985 STARTUP
(1979 dollars)

Technology	Total Erected Costs (\$/kW)	Efficiency (percent)	Capacity (MW)
Conventional Pulverized Coal			
Current FGD	532-610	34.0-35.0	700
Advanced FGD	618-740	31.5-32.5	700
Fluidized Bed			
Atmospheric (AFB)	375-589	34.0-35.0	700
Pressurized (PFB)	740-1329	39.5-40.5	700
Combined Cycle Gasification			
Current Turbines	791-1536	35.8-37.1	700
Advanced Turbines	630-1301	40.6-38.7	700
Refuel Existing Facilities			
Coal-Oil Mixture*	241-277	36.0-31.0	200
Coal-Derived Liquids	1273-1912	20.2-25.2	233
Low & Medium Btu Gas	389-452	28.5-33.1	233

*Capital costs for a dedicated preparation plant with FGD, and a centralized preparation plant with clean fuel would be appreciably lower.

- Notes: (1) Ranges of data shown represent inputs from different estimators for unique concept within same general power plant classification.
- (2) Capital costs to refuel existing facilities represent fuel production facilities that could be off site and owned by other than the utility.

FIGURE 3
RELATIVE COST OF ELECTRICITY FOR NEW
POWER PLANTS 1990 START-UP

FIGURE 4
RELATIVE COST OF ELECTRICITY FOR CONVERTED
PLANTS 1985 START-UP

the gasification combined cycle systems is primarily due to the number of different designs used in preparing the estimates.

Inspection of Figure 3 reveals that no significant economic difference among the new systems can be identified. Given the uncertainty associated with the technical performance of the new systems considered, additional information and further refinement of the cost data will be required before economic criteria can be used as a basis for selecting among alternative R&D strategies for developing the technologies.

The relative life cycle Cost of Electricity (COE) for the conversion systems starting operation in 1985 is shown in Figure 4. The year 1985 was selected since, based upon the market analysis, conversions will occur some time during the 1980s and most of the technologies can become commercially available by 1985 or shortly thereafter. Also shown are the COEs of a "do nothing" alternative, i.e., continued use of an existing oil facility for 10 years. The 10-year cost of using an existing oil facility is presented to reflect the impact on the comparison when delays are considered. The COE of conversions using the technologies considered is lower than the 10-year alternative of continuing use of an existing oil facility. Based upon the above, one can conclude that if the technology becomes commercially available, immediate conversion is indicated. A similar conclusion is drawn when one compares the cost of continuing use of oil with new system COE's.

Furthermore, since oil price increases faster than both construction cost and coal costs, the difference between the COE of new and conversion systems and the COE of continued use of oil will increase as the assumed initial year of operation increases, thereby increasing the economic pressures to displace the existing oil facility.

If a new technology alternative is not available, then the cost of COM should be compared to use of the existing oil-fired facility for the appropriate period of time. The life cycle cost of using the existing facility for 10 years is therefore presented in Figure 4. When the cost of COM and coal-derived liquids is compared with the 10-year continued use of oil, then the economics of the conversions are better than continued use of oil.

In summary, one can draw the following conclusions from the economic comparison:

Capacity Expansion

- Based upon available information, no significant economic difference among the new systems analyzed could be identified.

Replacement of Existing Oil

- Except for coal derived liquids and COM, all conversions analyzed are, when commercially available, less expensive than continuing use of oil in an existing oil facility.
- If COM is the only alternative available for 10 years, after its commercial availability, then conversion to COM is indicated.

ENVIRONMENTAL ASSESSMENT

Under the Clean Air Act of 1970 and the Amendments of 1977, the Environmental Protection Agency (EPA) was given the authority to establish New Source Performance Standards (NSPS) for stationary power plants and to establish National Ambient Air Quality Standards (NAAQS) for the country. Requirements under NAAQS can be significantly more stringent than NSPS. In unpolluted areas, Prevention of Significant Deterioration Regulations specify that Best Available Control Technology (BACT) be applied to the new power plant. In polluted areas, Nonattainment Regulations require that Lowest Achievable Emission Rate (LAER) technology be applied. BACT and LAER are determined on a case-by-case basis. Generally, BACT is more stringent than New Source Performance Standards and LAER is more stringent than BACT.

Thus, NSPS contain only minimum standards. Moreover, there are two sets of standards for electric power plants. The Electric Utility Steam Generating Standards apply to conventional coal-fired and atmospheric fluidized-bed (AFB) boilers and the Stationary Gas Turbine Standards apply to gasification combined cycle plants. The specific standards for pressurized fluidized bed (PFB) are uncertain at this time because the PFB supplies energy to both a steam plant and a gas turbine.

The best technique for stating and comparing emissions in advanced system studies is on the basis of quantity of pollutant per

unit of electric output. A survey of the available technical literature was conducted to locate power plant configurations using state-of-the-art and advanced pollution control technology. The results of this investigation are shown on Table 8. All of the data shown have been adjusted to reflect the use of an Illinois coal containing 3.7 percent sulfur and a higher heating value of 12,235 Btu per pound. The data shown for the advanced coal-based technologies are manufacturers' projections based on experimental test data. The actual emissions and resource consumption of these power plants must be proven in full-sized demonstration units.

A comparison of gaseous emissions from these power technologies is shown in Table 8. The conventional steam plant uses lime scrubbers (with on-site calcination) to control sulfur dioxide, staged combustion to control oxides of nitrogen (NO_x), and a baghouse to control particulate emissions. The sulfur removal efficiency of the scrubbers ranges from 90- to 95-percent. Most scrubber manufacturers will guarantee a 90-percent removal rate; some up to 95-percent on a case-by-case basis. New flue gas desulfurization technologies are being developed to improve scrubber reliability and maintainability and to produce a useful sulfur byproduct. However, SO_2 removal efficiencies of FGD systems might not be improved above the 90-95-percent shown in Table 8.

The coal-oil mixture (COM) plant uses control technology similar to that of the conventional steam plant. The fuel is assumed to be a

one-to-one mixture of 3.7 percent sulfur coal and 2.0-percent sulfur fuel oil, yielding a total sulfur content of 2.8 percent. As a result, the SO₂ emission rate of the COM plant at a 90-percent removal efficiency is comparable to that of the conventional coal plant at a 95-percent removal efficiency.*

The atmospheric fluidized-bed (AFB) plant uses in-bed limestone-sulfur reactions to control SO₂ emissions. Sulfur retention efficiencies of 86 to 90 percent have been reported, with a possible 95 percent retention from a German design. Nitrogen oxide emissions are mostly "fuel NO_x" since the low bed temperature of 1500-1650°F does not favor the production of "thermal NO_x". A baghouse filter is required for particulate control.

The pressurized fluidized-bed (PFB) plant uses pollution control technology similar to that used by the AFB except that dolomite is used as the sulfur sorbent instead of limestone. Sulfur retention efficiencies of 90- to 98-percent have been reported in bench-scale and process development units.

The gasification combined cycle data shown in Table 8 has been divided into two groups.** The "current turbine" plants use currently available gas turbines having firing temperatures in the 1950-2150°F range. The "advanced turbine" assumes gas turbines

*While individual state regulations may be more stringent, EPA has decided that any existing boiler can convert to COM without falling under the NSPS.

**Several gasifiers are considered for both current and advanced turbines. See Section 6.4, Volume III for descriptions.

that will have firing temperatures in the 2600-3000°F range. There is no DOE program directed at the 2150-2600°F range. However, industry (EPRI, GE, Westinghouse and UTC) believes that 2300°F can be achieved through growth of current turbine concepts. This potential technology level was not covered in the analyses performed under this study.

The pollution control system for the gasification combined cycle plants consists of pre-combustion removal of sulfur and nitrogen compounds and particulates from the fuel gas and combustion modification (as needed) to reduce thermal NO_x. The range in emission levels reflects the estimates found in a wide range of power plant configurations. Each configuration met or bettered the current gas turbine NSPS. The sulfur removal systems use proven techniques currently in service in the natural gas and synthesis gas industries and have the capability for reducing SO₂ emissions to levels well below current NSPS. Two manufacturers of this equipment will guarantee sulfur removal efficiencies of 99.9+ percent. The fuel-bound nitrogen compounds and particulates are scrubbed from the fuel by multiple water washes such that "fuel NO_x" and particulate emissions are virtually non-existent. In the power plants that produce and burn medium-Btu gas, "thermal NO_x" is controlled by steam or water injection into the combustor to reduce flame temperature. In the plants that produce and burn low-Btu gas, "thermal NO_x" is so low that combustion controls are not likely to be needed because of the relatively low flame temperature of low-Btu gas.

A comparison of estimated solid and liquid wastes from the five coal-based technologies is shown in Table 8. The conventional steam plant, using the lime slurry scrubber, produces a wet calcium sulfite sludge that is difficult to dispose. The particles do not settle out, and when placed in a pond, contaminants may leach into the soil. Other scrubber systems are being developed whose byproduct is in some saleable or easily disposable form. The solid byproduct from the conventional plant is coal ash which may present a disposal problem. The leachate from ash disposal sites could cause groundwater pollution. The liquid waste is mainly boiler and cooling tower blowdown water (95-percent) and general plant waste water.

The waste products shown in Table 8 for the COM plant are similar in nature to those of the conventional coal-fired steam plant. The solid waste and scrubber sludge are less than those of the conventional plant because the coal-oil fuel contains less ash and sulfur per pound of fuel.

The waste products of the AFB and PFB power plants are similar in nature. The solid effluents shown in Table 8 consist of coal ash plus the calcium-sulfur compounds formed during the sulfur capture reactions. The wide ranges shown reflect the use of different levels of calcium-to-sulfur (Ca/S) mole ratio. The high end of each range represents the Ca/S required for "once through" sorbent utilization. The low ends represent the reduced Ca/S needed if the sorbent is recycled and elemental sulfur is produced as a by-product. The liquid wastes are mainly cooling tower blowdown and general plant use.

TABLE 8

ENVIRONMENTAL ISSUES FOR COAL-BASED POWER TECHNOLOGIES

	Conv. Steam ⁽¹⁾	COM with FGD	AFB	PFB	GCC	
					Current ⁽⁴⁾	Advanced ⁽⁵⁾
<u>Performance</u>						
Overall Plant Efficiency, %	34	34	34-36	38-40	36-40	40-44
<u>Gaseous Emissions</u>						
Emissions, lb/kWh						
Sulfur Dioxide, 10 ⁻⁴	31-61	16-33	58-66	10-55	1-57	1-50
% Sulfur Removal	95-99	95-99	90 ⁽²⁾	98-99	99.9-99	99.8-99
Nitrogen Oxides, 10 ⁻⁴	61	35	27-28	17-18	3-17 ⁽⁶⁾	3-37
Particulates, 10 ⁻⁵	31	12-32	29-30	26-27	1-2	1-2
<u>Solid and Liquid Wastes</u>						
Waste Products						
Solids, lb/kWh, 10 ⁻²	8	3	17-41	12-30	7-8	6-7
Sludge, lb/kWh, 10 ⁻²	13-14	10-11	0	0	0	0
Liquids, gal/kWh, 10 ⁻²	18	18	16	14	9-29	5-13
Byproduct Sulfur lb/kWh, 10 ⁻³	0	0	0-21	0-18	23-26	21-26
<u>Resource Consumption</u>						
Coal Consumption, lb/kWh, 10 ⁻²	83	65 ⁽³⁾	78-81	70-74	69-78	63-70
Sorbent Consumption, lb/kWh, 10 ⁻²	11	8	11-45	8-33	0	0
Water Consumption, gal/kWh, 10 ⁻²	77-78	75	61	54	26-61	36-54
Land Requirements, acres/100MW _e						
Plant	12	10	13-14	14-15	12-37	11-33
Disposal	150-161	114-122	57-140	41-103	Included Above	Included Above

Coal: Illinois No. 6
12,235 Btu/16 HHV

Nomenclature:

COM - Coal Oil Mixture

AFB - AFB Steam Plant

PFB - PFB Combined Cycle

GCC - Gasification Combined Cycle

Notes:

(1) Lime slurry scrubber; on-site calcination of limestone

(2) Possible 95% S removal from German Lurgi Circulating Bed

(3) Coal + Oil

(4) 1950-2150°F Gas Turbines, Low and Medium Btu fuel gas

(5) 2600-3000°F Gas Turbines, Low Btu fuel gas (Medium Btu gas cases not analyzed).

(6) Low Btu gas - no combustion modification for NO_x control
Medium Btu gas - water or steam injectionConv. Steam, COM, AFB, and PFB Plants meet EPA NSPS for Steam Power Plants;
GCC Plants meet EPA NSPS for Gas Turbines

The waste products of the gasification combined cycles are coal ash and waste water. As in the case of the other power plants, the waste water is predominantly cooling tower blowdown. The wide ranges in waste water shown in Table 8 are due to the differing blowdown to circulating water criteria of the plant designers. The gasification combined cycle produces elemental sulfur as a byproduct of the fuel cleaning. This is not a waste since sulfur is in demand by the chemical industry.

The resource requirements of the five power technologies are shown in Table 8. The coal consumption of each plant is proportional to the plant's coal-to-busbar efficiency. The coal-oil consumption of the COM plant is small because the fuel has a heating value 28 percent greater than coal. The conventional steam, COM, AFB, and PFB plants require a calcium-based sorbent for sulfur removal. Due to the characteristics of the sulfur removal chemistry, the AFB and PFB plants require more sorbent per kilowatt hour than does the conventional steam plant. The sorbent requirements of the AFB and PFB can be reduced by the addition of a sorbent regeneration system. However, the addition of such a system degrades plant efficiency by about 5 percent. The AFB and PFB plant efficiency and sorbent consumption ranges reflect the addition of sorbent regeneration and sulfur recovery. The sorbent requirement of the COM power plant is less than that of the conventional steam plant because the coal-oil mixture used in this study contains only 2.8-percent sulfur

while the assumed coal, alone, has a sulfur content of 3.7 percent. The gasification combined cycles regenerate their sulfur sorbent as part of the cleanup system and require little, if any, sorbent makeup.

The water requirements of these power plants are predominantly steam plant cooling tower makeup water to account for blowdown and evaporative losses. The wide ranges shown for the AFB, PFB and gasification combined cycle plants reflect the wide disparity in designer assumptions found in the technical literature. The water consumption of the PFB and gasification combined cycles tends to be lower than those other systems because part of the power output of these plants comes from gas turbines. For example, in the PFB steam system the gas turbines supply 0-25 percent of the total output, and in the gasification combined cycle the gas turbines supply 50 to 70 percent of the total output.

The land requirements for the basic power plant are similar for all of the power technologies shown in Table 8, ranging from 10 to 15 acres per 100 megawatts. Land requirements for the disposal of wastes tend to be more uncertain. The disposal requirements of the conventional steam and COM plants can be substantial due to the nature of the wet waste sludge byproduct. The disposal requirements of the AFB and PFB plants are lower than the wet sludge requirement of the conventional plant because the AFB and PFB wastes are solid in nature. The disposal requirements of the gasification combined cycle

plants are low because the only solid waste product is coal ash which can easily be hauled away. In Table 8 the disposal requirements of the gasification combined cycle are included in the plant acreage.

The gasification combined cycle shows the potential for extremely low gaseous emission rates by applying technologies currently in use in the natural gas and chemical industries. However, the combination of these technologies in an electric power plant has not been demonstrated. The PFB power plant shows the potential for emission rates that approach those of the gasification combined cycle. Relative to the PFB, the gasification combined cycle produces less solid and liquid wastes. In addition the gasification combined cycle requires little or no makeup sorbent.

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PROGRAM APPROACH

The overall evaluation resulting from this study is presented in Figure 5.

Market Opportunity

A substantial national inventory of oil and gas-fired power plants exists. Most of these plants have a remaining serviceable life of two decades or more. In most NERC regions their continued dependence on high cost fuels will tend to relegate them, through economic dispatch, towards peaking and standby service yielding low load factors. These plants are promising candidates for refueling and/or repowering with coal. The most significant limiting constraint is expected to be land availability. Environmental factors are also expected to restrain their conversion, but technology can provide a means towards resolution of issues in this area.

The conversion of an existing plant to use of coal-oil mixtures offers promise for existing steam facilities, including those that have virtually no adjacent land. However, the marginal cost of electricity from COM is high compared with the expected costs of coal or nuclear. Thus, economic dispatch may relegate the COM-fueled plant to low usage; hence low load factors.

Availability of land within a few miles of an existing power plant that lacks adjacent land for expansion offers a potential opportunity for installation of a coal gasification facility and conversion of the existing steam plant to operate on medium-Btu gas. This situation also opens the opportunity for repowering the existing

FIGURE 5
OVERALL EVALUATION
OF COAL COMBINED CYCLE SYSTEMS

steam plant at some future time to meet local growth in electricity demand. A central coal gasification facility could provide fuel to many power plant units within a close geographical region (e.g., within the metropolitan area).

If more land adjacent to the existing plant is available, the options for conversion of an existing plant increase. The first assignment of available land would be for coal storage and handling functions. This land area requirement can be minimized by providing only live storage on site and depending on barges, railroad cars and other site locations for stockpile of coal in addition to disposal of solid waste.

Assuming sufficient land is available on site, the existing boiler could be converted to coal combustion or a new boiler could be constructed. Conversion of an existing oil-designed boiler to coal is expected to require a derating on the order of 40 percent, although conversion to COM would require less derating. A new boiler could be constructed on an adjacent site or the same site of the original boiler. Such a new boiler could be either pulverized-coal, AFB or PFB combustion. Conversion to PFB could yield up to 25 percent increased power.

A need by the utility for significant additional power to meet growth in demand can be achieved through conversion to a coal gasification combined cycle. This conversion can take a variety of forms. In one version the waste heat recovery unit of the gas

turbine provides feedwater heating to the existing steam plant. Another concept involves the flow of the gas turbine exhaust to the existing steam boiler with supplementary firing. In the most advanced form, the waste heat recovery unit of the gas turbine plus the waste heat of the coal gasification system raises steam to meet the design conditions of the existing steam turbine. However, this latter concept may require an advancement in gas turbine firing temperature from the current 2000°F level to above the 2300°F level, depending on the specific gasifier.

The coal-oil mixture option is the only one of the above concepts that would not seriously be considered for a new power plant facility at a new site because the primary objection of COM technology is refueling.. All of the others are genuine competitors.

As a general representation of the utility opportunity, the refueling of existing oil- and gas-fired steam plants offers a sizeable potential. Some repowering of existing plants may be of interest to utilities. Finally, another opportunity arises out of the need to replace worn-out plants and to meet growth demand after the 1990s. Crucial factors for decision making will cover technology, finance and environment.

Technology Status

Any new power plant innovation requires successful demonstrations before serious considerations can be given to it by electric utilities. Attributes to be demonstrated include capital and

operating costs, environmental compliance, resource requirements, reliability and maintainability and acceptability to regulatory bodies. The final criteria constraining utility acceptance is whether industrial suppliers will offer a suitable warranty on the equipment and whether a means can be found to warranty the integration of the entire power system. This latter warranty requirement may be the most difficult obstacle to acceptance of a new power plant innovation, particularly as applied to conversion of an existing facility.

Current estimates of capital and operating costs are insufficient in accuracy to substantiate any elimination of concepts on this basis. Technology advancements could yield benefits for every concept. The concept most significantly sensitive to technology advancement is the gasification combined cycle where both improved coal gasification techniques and raised turbine firing temperatures can reap significant performance and cost improvements.

The technical criteria yielding the largest apparent differentiation among concepts relate to environmental issues. PFB combined cycles appear to offer the potential for 70-percent reduction in the sulfur and nitrogen compound air emissions relative to the pulverized-coal steam plant with FGD. Gasification combined cycle appears to offer the potential for 95-percent reduction in these emissions plus exceptionally low particulate emissions. These attractive analytical predictions require experimental verification. The low water consumption of gasification combined cycle is also noteworthy.

It is generally recognized that small differences in technical and economic attributes between competing candidates can have significant effect on their respective market penetration after these differences are proven. Power plant demonstrations will improve the accuracy of these differences for the benefit of utility decision makers. Final utility decisions will be made on site-specific bases.

These considerations yield the conclusion that coal combined cycle concepts have a strong potential for a significant future market position. More definitive data are required that can only be achieved through demonstrations in a prototype installation. Either conversion of existing plants or construction of completely new facilities would achieve this objective. There appears to be no technical difference between the use of an existing steam plant or the construction of a new plant for utility acceptance of the demonstration results. Conversion of existing facilities could save money and time, depending on the specific site situation. Whatever demonstration is performed should be closely tied to the regions expected to have the greatest future need for incorporating the demonstrated technologies.

The progression of activities in a demonstration project should yield a continuing refinement of the technical data that ultimately would be used by electric utilities in their equipment acquisition decisions. Any point along this trail that indicates poor prospects for eventual market penetration warrants an immediate decision

on cancellation or redirection. It would be advantageous to carry many concepts through the preliminary engineering stage to examine site-specific situations in more detail.

Demonstration Program

Each of the combined cycle concepts requires both a new combustion technology and a new turbine technology in order to achieve a level of performance sufficient for significant market penetration on an economic basis. The necessary advancements required for the PFB combined cycle include scaleup of the fluidized-bed system and protective coatings for the hot parts of the expansion turbine to operate in a highly corrosive atmosphere at temperatures around 1600°F. In the case of gasification combined cycle, coal gasifiers need to be scaled from pilot size to full size and combustion turbine firing temperatures need to be increased to around 2300°F. Further increase in combustion turbine firing temperature would increase the economic advantage of this latter concept. Thus, each combined cycle system has two areas of major technological risk.

It may be practical to advance the technology for the PFB combined cycle system by addressing one area of technical advancement at a time. Combustion technology can be separated from turbine technology through proper phasing of the program activities. The first step would involve demonstrations of the PFB boiler process. A current model gas turbine could be used in this first phase of

demonstration for the PFB system, but operated at low temperature (1000°-1400°F) to avoid corrosion.

After successful demonstration of the combustion processes in full-scale equipment, the separately developed 1600°F turbine required for an economical PFB system could be applied to the same facility. This turbine would probably be a current-model engine altered by protective coatings on the hot section parts.

For the gasification combined cycle system, a 2000°F combustion turbine and a waste heat recovery unit could be initially installed at the plant site. Following successful system operation, the gas turbine could be rebuilt for a higher temperature (2300°F) when the technology is developed. The High Temperature Turbine Technology (HTTT) Program results (2600-3000°F) could also be installed when available.

These multiple step approaches would limit the technical risk by narrowing the significant uncertainties to one element at a time. However, the entire multistep approach has to be incorporated into the planning of the demonstration program and into the system design at the beginning.

Conclusion

Both combined cycle concepts offer attractive attributes for ultimate application in the electric utility market. These can be applied to both conversions and new plants, both market segments being significant in size. The sequencing of activities by

demonstrating the combustion processes prior to the advanced gas turbines would minimize technical risk. Results of analytical economic comparisons generated to date are inadequate for a final selection from among the two combined cycle concepts as compared with conventional coal-fired steam plants. However, the environmental potential of coal combined cycles appears to be very strong.

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Coal Combined Cycle System Study

Volume I—Summary

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