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A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology

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William Harrison

A CRITICAL REVIEW OF
EFFICIENT AND ENVIRONMENTALLY SOUND
COAL UTILIZATION TECHNOLOGY

May 1995

THE NATIONAL COAL COUNCIL

THE NATIONAL COAL COUNCIL

Joseph W. Craft III, Chairman

James F. McAvoy, Executive Director

U.S. DEPARTMENT OF ENERGY

Hazel Rollins O'Leary, Secretary

The National Coal Council is a Federal advisory committee to the Secretary of Energy.

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May 17, 1995

The Honorable Hazel R. O'Leary
Secretary of Energy
Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Madam Secretary:

The National Coal Council is pleased to submit for your review the report entitled A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology. This report was formally approved by the Council on May 17, 1995. We believe that it is responsive to your letter to the Council, dated May 3, 1994, in which you requested "a single source document which defines state-of-the-technology for coal-using systems and associated benefits."

Although not an objective of the report, the exercise of identifying and reviewing coal utilization technologies clearly confirmed the tremendous value of collaboration between industry and the Department of Energy in the Clean Coal Technology Program. Almost every technology addressed in the report exhibits the comprehensive nature of this collaboration as well as the foresight and wisdom in setting the priorities and objectives which were established.

In order to respond to your request, the Council formed a Working Group consisting of individuals with expertise in the relevant areas of technology. Members of the Working Group were either members of the Council or recommended by members of the Council, and all had excellent credentials for the assignments they undertook.

Each coal utilization process or system reviewed in the report is evaluated in terms of readiness for commercialization and any remaining development needs which must be addressed before commercialization is practical.

To quote from the opening statement of the Executive Summary of the report:

"This report clearly shows that technology can enable coal to continue and perhaps expand its major role in the energy portfolio of the U.S. Through currently available and emerging processes and

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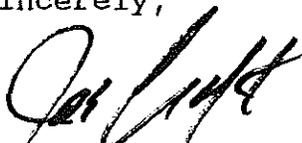
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systems, coal will help to keep energy prices stable and reasonable while making it possible to achieve key national goals. Such expectations for coal and coal utilization technology are basic to national economic stability and will support sustainable development throughout the world."

Existence of the technology, however, does not guarantee that the promising outlook suggested by this quotation will be forthcoming. In this context, there are a few general conclusions, also mentioned in the Executive Summary, which must be recognized. All new technologies need some form of risk-sharing for first-of-a-kind plants in order to progress quickly from demonstration to commercial use, and many of the most promising technologies still require demonstration at full commercial scale. Among the most promising technologies, many still require extraordinary care because, as federal and state environmental requirements are mandated, the relative importance of some of these technologies will change, and because a wide range of technologies is necessary to assure economically viable and environmentally acceptable coal options in both the short term and long term.

The obstacles outlined above are among those that must be overcome before some of the most promising technologies can be commercialized, thereby ensuring that coal will continue to fulfill its role of helping to achieve national energy goals.

Sincerely,



Joseph W. Craft III
Chairman

PREFACE

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the Secretary of Energy on general policy matters relating to Coal. The Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

The members of the National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise, and stature in their respective fields of endeavor. They reflect a wide geographic area of the United States, representing more than 30 states, and a broad spectrum of diverse interests from business, industry, and other such groups as:

- *Large and small coal producers*
- *Coal users such as electric utilities and industrial users*
- *Rail, waterways, and trucking industries as well as port authorities*
- *Academia*
- *Research organizations*
- *Industrial equipment manufacturers*
- *Environmental interests*
- *State government, including governors, lieutenant governors, legislators, and public utility commissioners*
- *Consumer groups, including special women's organizations*
- *Consultants from scientific, technical, general business, and financial specialty areas*
- *Attorneys*
- *Special-interest groups that are regional or state in concentration*
- *Indian tribes*

The National Coal Council provides its advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

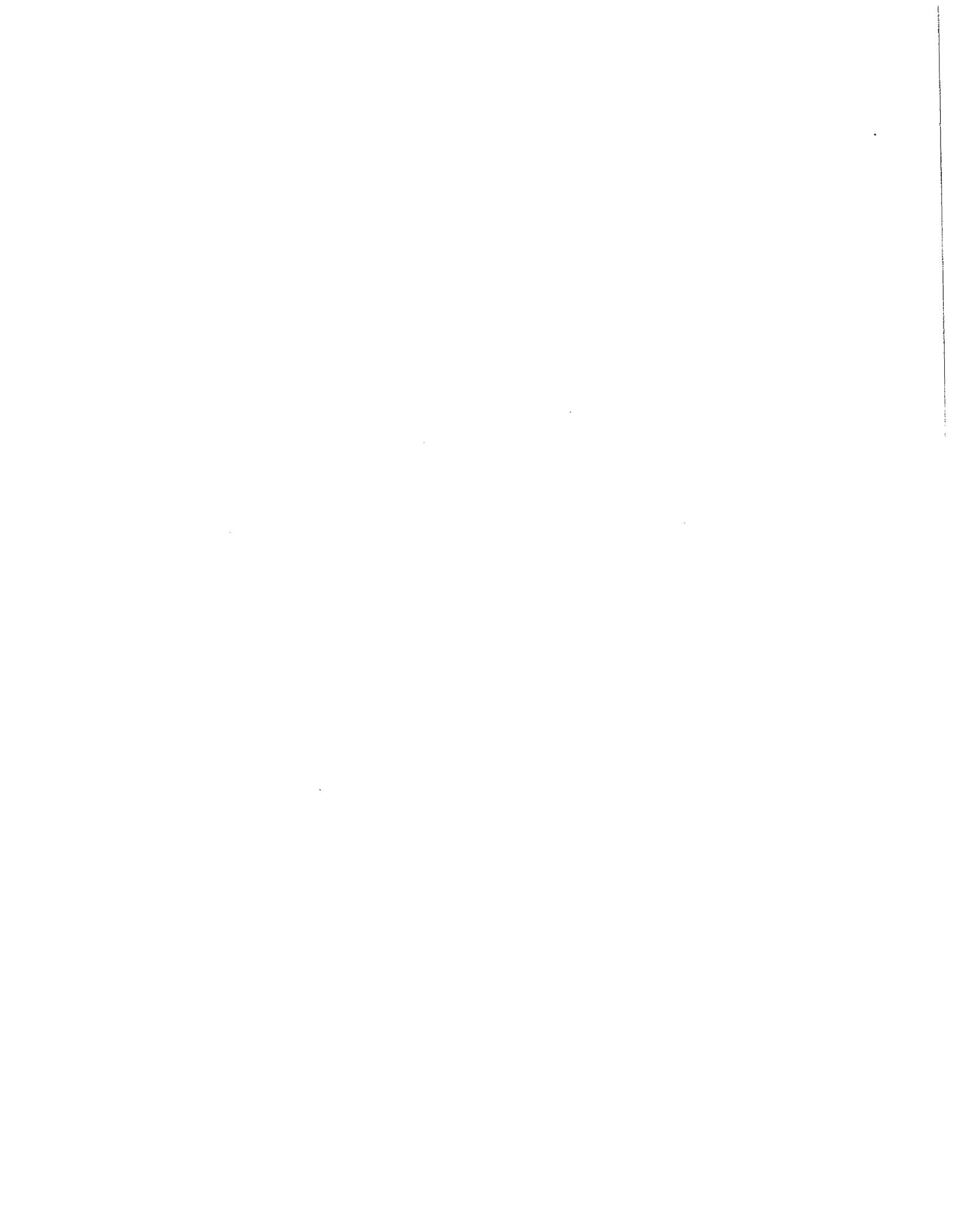


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FOREWORD

For over thirty years, the U.S. Department of Energy (DOE) and its predecessor Federal agencies have sponsored coal research, development, and demonstration projects to enhance the utilization of coal, the nation's most abundant fuel. These efforts, complementing developments and improvements being made by suppliers of coal processes and technologies, led to DOE's Clean Coal Technology (CCT) Program, initiated in 1986. This initiative resulted in the largest and most successful coal collaboration ever undertaken between industry and the Federal Government. Its purpose was to demonstrate environmentally sound, cost-effective retrofit and new coal-based power systems, processes, and components.

In a report released in February 1994, the National Coal Council (NCC) recommended that DOE and Congress focus on a program to reduce risks associated with "first of a kind" (FOAK) commercial systems using advanced coal technology. The report, *Clean Coal Technology for Sustainable Development*, recommended specifically that a Federal-level incentive program be established to share these risks properly between industry and the Federal Government.

In response to recommendations in the report, and to similar recommendations from industry, DOE established a new initiative to define potential commercialization options for Clean Coal Technology. This initiative is extremely important in effecting a smooth transition from the demonstration program to initial commercial deployment of the demonstrated technologies.

At the same time, Secretary of Energy Hazel R. O'Leary requested that the National Coal Council review the scope of coal utilization technologies and prepare "a single source document which defines state-of-the-technology for coal-using systems and associated benefits." This request was forwarded to NCC on May 3, 1994. The task of preparing the report was assigned to the NCC's Coal Technology Subcommittee, which formed a Working Group to compile the text. The Working Group included both members of the NCC and a number of non-members with expertise of special importance for this study.

This report uses as a foundation several earlier NCC studies, including *Clean Coal Technology* (1986), *Innovative Clean Coal Technology Deployment* (1988), *Export of Coal and Coal Technology* (1993), and *Clean Coal Technology for Sustainable Development* (1994). It is organized as follows:

- Chapter 1: Perspective
- Chapter 2: The Value of Coal
- Chapter 3: Technologies Related to Power Generation

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- Chapter 4: Other Advanced Power Systems
- Chapter 5: Coal Conversion

The scope of the report requires a broad, comprehensive review of the status of coal technologies, processes, and systems. For each technology, therefore, and to the extent practicable, the report includes data on five subjects: technology description, development status, environmental performance, commercial impact, and development needs.

The report examines a number of processes and systems which are included in a broad definition of "coal utilization technology." Chapter I sets forth the general significance of clean coal technology and the implications of coal technology for national policy and the environment. It is pointed out that the use of coal and coal technology fully supports national objectives and that, in fact, many basic national objectives cannot be realized without coal. Chapter II emphasizes that coal provides the U.S with unique advantages relative to most other nations in the world; because of its role in keeping energy costs within reasonable limits, coal is crucial to America's economy, employment, productivity, and balance of international trade.

Chapters III, IV, and V describe individual processes and systems, with readiness for commercialization and remaining development needs assessed in each case. These chapters were written with a view to keeping the discussions as brief as possible while still addressing all topics needed to ensure that the objectives of the report were fully realized. For those seeking more detail, references are provided for each major topic. Every process and/or system, including an assessment of its development status, is listed in Appendix A, Exhibit 1. Exhibits 2, 3, 4, and 5, also in Appendix A, list the assigned priorities for satisfying the need for research, development, demonstration, and commercialization assistance, respectively.

Other Appendices provide a description of the National Coal Council (Appendix B); lists of members of the National Coal Council (Appendix C), Coal Policy Committee (Appendix D), Technology Subcommittee (Appendix E), and Working Group (Appendix F); acknowledgements of other contributors who provided information or other services to the Working Group (Appendix G); a Glossary of Terms (Appendix H); and correspondence between the National Coal Council and the U.S. Department of Energy with respect to this project (Appendix I).

The National Coal Council is pleased to offer this assessment of the state-of-the-technology of coal-using systems and their associated benefits. The Council believes that this report, *A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology*, is responsive to Secretary O'Leary's request and that it provides a strong basis for future DOE activities related to coal utilization technologies and to underlying process research and development programs.

EXECUTIVE SUMMARY

Overview

This report clearly shows that technology can enable coal to continue and perhaps expand its major role in the energy portfolio of the U.S. Through currently available and emerging processes and systems, coal will help to keep energy prices stable and reasonable while making it possible to achieve key national goals. Such expectations for coal and coal utilization technology are basic to national economic stability and will support sustainable development throughout the world.

Identifying the Needs of "Coal Utilization Technology"

In this report, consistent with Secretary O'Leary's request, coal utilization technologies have been comprehensively reviewed and evaluated from the perspective of their potential value to industry. The objective was to determine the status of each technology relative to its potential role in future clean power generation and other coal conversion applications within the context of sustainable development.

To identify and analyze various technologies, the broad category of "Coal Utilization Technology" has been divided into subcategories, discussed in Chapters III, IV, and V. Forty-four technologies have been examined with respect to their positions along the path from research through the required subsequent stages of development, demonstration, and, finally, commercialization. An assessment of the research, development, demonstration, and commercialization needs of each technology is provided in Appendix A, Exhibit 1.

Five key conclusions may be drawn from the information presented in Exhibit 1:

1. *All new technologies need some form of risk sharing for first-of-a-kind plants in order to progress quickly from demonstration to commercial use.*
2. *Many of the most promising technologies still require demonstration at full commercial scale.*
3. *Many of the promising technologies still require fundamental research and development, as well as related significant investments, before their potential applicability for future utilization can be evaluated properly.*
4. *As Federal and state environmental requirements are mandated, the relative importance of many of these technologies changes.*

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5. *A wide range of technologies is necessary to assure economically viable and environmentally acceptable coal options in both the short term and the long term.*

Nine technologies are ready for initial commercialization but require some form of assistance for deployment and acceptance in the marketplace. Of the nineteen technologies in need of further support as demonstration projects in order to ensure a better assessment of their technical and economic viability, fourteen are being demonstrated in the Clean Coal Technology (CCT) Program. *It is recommended that all of these fourteen CCT demonstration projects be completed.*

Similarly, twenty-five technologies were seen to have significant development needs. Many of these projects offer the potential for future applications, but, as in the case for research needs, the manner and timing of meeting these needs will determine the ultimate commercial outcome.

Out of the forty-four technologies listed, twenty-two still have significant research needs. In most cases, it is difficult to predict the future commercial success of these technologies until some of the research needs are met. In other words, both the manner and the timing of addressing the needs of a given technology may determine whether or not the technology can ever become commercially viable, or to what extent it will penetrate the commercial market.

Priorities for Research, Development, Demonstration, and Commercial Assistance

A critical review of coal utilization technologies enabled the ordering of priorities for each technology with respect to its needs in the steps along the path from research to commercialization. *It is recommended that the needs of the select list of subject areas and technologies shown in Exhibits 2, 3, 4, and 5 in Appendix A be met as soon as possible so they may advance coal utilization early in the next century.*

The priority rankings took into account the relative importance of various key factors such as the potential impact of new environmental requirements on the power industry, maximum possible margins of improvement over currently available technology, potential impact on the coal utilization industries, and applicability of research or development to more than one technology.

Research

The critical research needs of eight technologies are prioritized in Appendix A, Exhibit 2. The highest research need is for new technologies to control toxic air emissions such as mercury and other heavy metal emissions. Metallic and ceramic materials and coatings to withstand high temperature oxidation, hot corrosion, and wear are next in priority

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because of their importance to the success of combustion turbines, pressurized fluidized bed combustion systems, advanced boilers, and recuperators.

Characterization of effluent streams from electrostatic precipitators, fabric filters, flue gas desulfurization, and selective catalytic reduction systems, as well as a topping system for capturing fine particulates, is ranked next due to concerns about control of hazardous air pollutant emissions from these emission control systems.

The major need in fuel cell technology is improved cathode life. The next priority is a postcombustion control and sequestration process for carbon dioxide emissions. Another research priority is to develop advanced formulations for selective catalytic reduction systems. Carbon monoxide conversion, catalyst chemistry, and slurry processes for conversion of synthesis gas are assigned the next priority.

Development

Six coal utilization technologies in need of additional development are prioritized in Appendix A, Exhibit 3. These technologies offer the greatest potential for early commercial success, based on their current status of development.

Hot gas clean-up and alkali and heavy metal control are key development areas which are critical to further improvement of the efficiency of integrated gasification combined cycles and advanced pressurized fluidized bed combustion systems. The next priority focuses on development of oxidation and corrosion resistant coatings for metallics and ceramics to withstand high temperature regimes of advanced gas turbine systems. The high operating temperatures of advanced gas turbines are conducive to production of oxides of nitrogen. Development of a catalytic combustion process would offer a valuable option to curb these emissions.

Technology for control of mercury emissions is an important need. Another major need is for development of a topping combustor for advanced pressurized fluidized bed systems. The combustor development which has been going on for some time should be accelerated to benefit advanced pressurized fluidized bed combustion technologies.

Fuel cells offer the potential to achieve very high energy conversion efficiency and low emissions. Cost-effective manufacturing process development would greatly enhance the applications of fuel cells as stand-alone power sources and as topping cycles for gas turbines.

An improved mist eliminator for high velocity scrubber systems is needed for wet flue gas desulfurization systems.

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Demonstration

Eight demonstration priorities are noted in Appendix A, Exhibit 4. Completion of the on-going Clean Coal Technology (CCT) demonstration projects and scale-up of the pressurized fluidized bed system to large commercial size (about 350 MW) are high priorities. The project sizes in the CCT program are not large enough to provide adequate quantitative assessment of the challenges and derived benefits of these technologies.

The current integrated gasification combined cycle demonstration projects under the CCT program should be completed. The Low Emissions Boiler Systems (LEBS) program also should be completed. This will demonstrate a variety of technologies to increase the thermal efficiency and emission control for pulverized coal-fired boilers. These may be adopted immediately, in part, in new designs and also may form the basis for ultra-efficient, ultra-clean pulverized coal-fired boilers.

It is recommended that all effluent streams of current projects in the CCT program be characterized to assess the need for hazardous air pollutant control and that the CCT demonstration projects on indirect-fired cycles and molten carbonate fuel cells be completed.

The utilization of key solid streams of the CCT program should be evaluated to determine effective byproduct utilization procedures. Projects for the control of sulfur dioxide and oxides of nitrogen in the CCT program should be completed. The economics of these control systems also must be evaluated.

Commercial Assistance

Technologies in need of commercialization assistance are prioritized in Appendix A, Exhibit 5. *It is recommended that mechanisms be established to provide commercialization assistance, in the form of risk-sharing and international marketing assistance, for five technologies which offer the greatest promise for near-term benefits. These projects are (1) integrated gasification combined cycle systems, (2) advanced pressurized fluidized bed combustion systems, (3) physical coal cleaning, (4) low rank coal beneficiation, and (5) coal-fired diesel engines.*

Major obvious impediments to deployment of any new technology relate to financial and technical risks associated with the first few installations of commercial size. Initial capital costs will be high, and investors will require some assurance not only of a reasonable return on their investments, but also of an adequate probability of commercial success. Scaling up the size of technical facilities always entails an element of uncertainty, directly translated into financial risk, and there is no proven strategy for going from demonstration to commercialization with absolute confidence. Therefore, rapid deployment of the

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technologies with the greatest promise of commercial success will require some mechanism for underwriting these risks. *It is recommended that the Federal Government create an insurance program to provide a safety net for the first-of-a-kind new commercial facilities. This should be done in partnership with coal stakeholders.*

The National Coal Council recognizes that the Administration and Congress are concerned about Federal outlays and balancing the Federal budget. An investment in advanced coal technology programs, however, should prove to be both very cost-effective and in the national interest. Most of these advanced coal technology systems offer significant environmental control advantages as well as higher efficiency performance over present systems. In addition, life cycle cost projections indicate a lower cost of power combined with the ability to meet stringent environmental requirements.

The Federal Government, in concert with industry, will have invested nearly \$10 billion in developing and demonstrating these advanced coal systems by the year 2000. In order to capitalize fully on this investment, continued Federal financial incentives are necessary for the first full-scale pre-commercial plants.

In a previous report by the National Coal Council, *Clean Coal Technology for Sustainable Development*, it was estimated that Federal incentives of approximately \$1.4 billion over fifteen years may be necessary to establish a domestic deployment program. *It is recommended that DOE consider a range of financial incentive options which not only can minimize Federal expenditures, but also can assure initial pre-commercial deployment of the systems.*

It is recommended that incentives be established (1) to shorten the time required for commercial deployment, (2) to improve prospects for exporting U.S. technology, and (3) to ensure continued benefits of environmental protection, energy efficiency, and "highest and best" economic use of the nation's most abundant domestic energy resource: coal.

One possible approach would be to extend tax credits to the first few commercial scale coal power systems. Some of the present CCT projects have successfully utilized the existing tax code (Internal Revenue Code, 94 FED, paragraph 4050, Section 29) "credit for producing fuel from a non-conventional source." This credit has proven to be an important factor in the ability to finance several CCT projects. Therefore, *it is recommended that Section 29 tax credit be extended and expanded.*

It is recommended that DOE consider expanding benefits of the Section 29 tax credits to advanced coal power systems, advanced emission control systems, and coal conversion processes which may require government risk-sharing in order to bring about commercialization of these technologies.

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It is further recommended that the "facility original placed in service date" be extended from the present "before January 1, 1997," to "before January 1, 2007." This will provide a ten-year window of incentive to meet projected capacity growth and environmental performance goals by the year 2010. This also would allow sufficient time to plan, design, permit, and construct qualifying facilities.

Research and development needs do not require as much financial underwriting as do the commercial installations, but, considering the scope of these needs and the benefits of ultimate commercial success, it is clear that significant financial support is deserved and will be required. Here again, coal stakeholders must recognize that their investments and participation in coal research and development are essential for their long-term success. Stakeholders are encouraged to consider creating an entity similar to the Electric Power Research Institute or the Gas Research Institute for the purpose of supporting and directing coal-related research. *It also is recommended that DOE maintain, to the maximum extent possible, support of coal technology research and development.*

Importance of Nurturing Coal Research Expertise

In Chapter V, Part D, under "Development Needs," it is pointed out that coal liquefaction technologies do not survive well "on the shelf" -- that the German technologies developed before World War II had to be reinvented during the 1970s and 1980s because the original experts were no longer available to guide the work. This is true of other coal utilization technologies as well. *It is recommended that DOE assume the responsibility of "technology caretaker" for coal liquefaction technology, since commercialization seems to be unlikely in the near future.*

This thought leads to a more profound question about how new coal technologies can be expected to emerge in the future if the supply of competent and experienced coal research personnel is allowed to disappear. All coal utilization technologies have roots in basic research, and a number of interacting scientific and engineering disciplines are always required throughout the process, from research through development and demonstration. The decline in the number of universities with faculty expertise and graduate research programs related to coal since the 1970s is a serious problem which threatens the future of coal technology. In addition to the current need for research, there will be a related need for trained personnel with experience in coal technologies to design and manage the advanced coal utilization facilities of the future.

Several of the sections outlining "Development Needs" in this report have pointed out the importance of university research in resolving some of the current technical problems. In order to address this need to nurture coal research expertise, a deliberate plan of implementation must be developed by DOE in concert with the industry or this is not likely to happen. *It is recommended that DOE, working with industry stakeholders, develop a*

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deliberate plan of implementation (1) to identify the persons and institutions where coal research expertise can now be found, (2) to provide adequate and stable levels of funding to sustain significant research programs, (3) to provide incentives for productive programs and competition between programs, and (4) to ensure rewarding career paths for graduate students who address coal-related topics.

Future Government/Industry Collaboration

As noted previously, the DOE Clean Coal Technology program is an outstanding and successful example of government/industry collaboration. *It is recommended that the high-priority needs addressed in this report be met by re-focusing the government/industry collaboration that proved successful with the DOE Clean Coal Technology program.*

There are several different levels of need which may be addressed by different collaborative mechanisms. For example, advanced technologies must be evaluated by individual prospective users to determine how the technologies can best be integrated into their facilities and business operations, and the economic effects on their businesses must be analyzed and understood. This could require selected new pilot plant studies and engineering feasibility studies for site-specific applications. In such cases, it may be feasible for DOE and a select number of prospective users to form "User Interest Groups" to manage collaboration on areas of mutual interest and to develop collaborative industry/government efforts.

Another example may be found in the refinement and enhancement of existing technologies. That is, new technologies must face competition, in some cases, from existing technologies which can be upgraded in performance through improvements in equipment or process operating conditions. Here again, collaboration with "User Interest Groups" can be effective.

DOE participation in "User Interest Groups" will promote transfer of DOE-developed technology to the marketplace and ensure retention of key "know-how" within the department. This approach also can allow DOE to maintain a broad portfolio of research activities with reduced funds by allowing industry to take the lead role in identifying and furthering development efforts.

Some industry groups already exist and are working together to resolve common problems. DOE also could participate in numerous small projects directed by the technology stakeholders. It is believed that this approach, if broadly implemented, would accelerate progress of technologies as they mature from embryonic to development scale. The purpose of each user group would be to determine barriers to commercialization and to conduct studies and contract for limited research on key questions that must be answered if these barriers are to be overcome. For this to be implemented, DOE needs to allocate

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a small percentage of its annual budget specifically for this purpose. *It is recommended that DOE consider cost-sharing with user groups that can demonstrate shared technical interests with DOE.*

Recommendations

1. The National Coal Council recommends that all fourteen Clean Coal Technology demonstration projects on indirect-fired cycles and molten carbonate fuel cells be completed.
2. The National Coal Council recommends that needs of the select list of subject areas and technologies shown in Exhibits 2, 3, 4, and 5 in Appendix A be met as soon as possible so they may advance coal utilization early in the next century.
3. The National Coal Council recommends that all effluent streams of current projects in the CCT Program be characterized to assess the need for hazardous air pollutant control.
4. The National Coal Council recommends that mechanisms be established to provide commercialization assistance, in the form of risk-sharing and international marketing assistance, for five technologies which offer the greatest promise for near-term benefits.
5. The National Coal Council recommends that the Federal Government create an insurance program to provide a safety net for the first-of-a-kind new commercial facilities. This should be done in a partnership with coal stakeholders.
6. The National Coal Council recommends that the U.S. Department of Energy consider a range of financial incentive options which not only can minimize Federal expenditures, but also can assure initial pre-commercial deployment of the systems.
7. The National Coal Council recommends that incentives be established (1) to shorten the time required for commercial deployment, (2) to improve prospects for exporting U.S. technology, and (3) to ensure continued benefits of environmental protection, energy efficiency, and "highest and best" economic use of the nation's most abundant domestic energy resource: coal.
8. The National Coal Council recommends that Section 29 of the existing tax code, "credit for producing fuel from a non-conventional source," be expanded to include advanced coal power systems, advanced emission control systems, and coal conversion processes which may require government risk-sharing in order to bring about commercialization of these technologies.

Executive Summary

9. The National Coal Council recommends that the "facility original placed in service date" be extended from the present "before January 1, 1997," to "before January 1, 2007." This will provide an additional ten-year window of incentive to meet projected capacity growth and environmental performance goals. This also would allow sufficient time to plan, design, permit, and construct qualifying facilities.
10. The National Coal Council recommends that DOE maintain, to the maximum extent possible, support for coal technology research and development.
11. The National Coal Council recommends that DOE assume the responsibility of "technology caretaker" for coal liquefaction technology, since commercialization seems to be unlikely in the near future.
12. The National Coal Council recommends that DOE, working with industry stakeholders, develop a deliberate plan of implementation (1) to identify the persons and institutions where coal research expertise can now be found, (2) to provide adequate and stable levels of funding to sustain significant research programs, (3) to provide incentives for productive programs and competition between programs, and (4) to ensure rewarding career paths for graduate students who address coal-related topics.
13. The National Coal Council recommends that the high-priority needs addressed in this report be met by re-focusing the government/industry collaboration that proved successful with the DOE Clean Coal Technology program.
14. The National Coal Council recommends that DOE consider cost-sharing with user groups that can demonstrate shared technical interests with DOE.

CHAPTER I

PERSPECTIVE

Introduction

National goals which are viewed as being essential to future security and well-being, such as full employment, increased industrial productivity, favorable balance of trade, reasonable costs of goods and services, and enhanced quality of life for all citizens, depend on adequate supplies of energy provided in an environmentally responsible manner at the lowest possible cost. Among the numerous energy resources available, traditional resources -- oil, natural gas, coal, "hydro," and uranium -- together still fill most of the nation's energy needs, though solar, geothermal, wind, and other non-traditional and alternative resources are expected to achieve an increased share of the total energy market. Among the traditional resources, the national interest is best served if each is allowed to fill those needs for which it is best suited.

In this context, it is clear that for many needs coal is an obvious choice. It is the most abundant energy resource, with domestic reserves significantly greater than oil and natural gas combined, and it can serve the demands for generation of electricity and certain other specialized energy conversion markets in an environmentally responsible manner at less cost than any alternative.

This matter has been addressed in previous reports of the National Coal Council: *The Long-Range Role of Coal in the Future Energy Strategy of the United States* (1990) and *The Near Term Role of Coal in the Future Energy Strategy of the United States* (1992).

Energy markets are dynamic and subject to rapid changes due to many interacting social and geopolitical forces. Included among these are forces at work which could prevent coal from reaching its full potential for cost-effectively meeting some energy needs for which it is best suited. The National Coal Council also has presented reports on two such forces: *Externalities* (1992) and *Improving Coal's Image -- A National Energy Strategy Imperative* (1992).

The principal applications of nuclear energy will be for generation of electricity. The primary market for coal also will be for generation of electricity, though coal can be expected to displace oil and natural gas in certain industrial and other applications where technically feasible and both environmentally and economically attractive. This will reduce national dependence on imports of oil (and of natural gas to some degree) and conserve

national dependence on imports of oil (and of natural gas to some degree) and conserve both for other uses for which they have uniquely desirable properties and, hence, higher value. In many cases, displacement of oil and natural gas by coal will come about indirectly through coal-generated electricity. Examples are found among prospects for electric vehicles and various new electro-technologies. Other possibilities include coal-derived fuels to substitute directly for oil and natural gas.

The purpose of this report is to collect and summarize current information on the status of coal utilization technologies in order to identify readily those which show the greatest promise for commercial deployment and to recommend strategies for the nation to realize the benefits from such technologies at the earliest possible date.

Importance of Clean Coal Technology

Coal's abundance and market stability will ensure its continued role in the energy supply, economic growth, and improvement in the general welfare of the United States and the world, particularly developing countries, for many decades to come. Even with advances being made by natural gas and alternative energy, coal still is projected to fuel more than half of this nation's electric power generation by 2005. This probably will remain true for the foreseeable future as projected increased power demand and need for base load production is expected to increase coal use.

Coal technologies *are* environmental technologies. Several new, developing coal utilization systems produce emissions comparable to those for natural gas systems. High efficiency power systems using advanced process technologies also reduce power plant carbon dioxide emissions. Many of the clean coal technologies also can capture hazardous air pollutants.

Over the past decade, great progress has been made in clean coal technologies. Some are just beginning to be introduced commercially, and a few have demonstrated commercial success; other more advanced and complex technologies are in the process of being built or completing their test runs. Continued research, development, and ultimately deployment of these systems and processes is essential to achieving sustainable energy and economic development in the United States, as well as to limiting emissions from the rapidly expanding use of coal throughout the developing world.

The People's Republic of China is adding between 10,000 and 12,000 MWe annually of new coal-fired capacity, using conventional steam cycle powerplants. This trend is expected to continue for the next decade or so as China revitalizes its economy. Similarly, Indonesia is planning to add 31,000 MWe of new coal capacity in the next 10 years, and India is planning to build at least 10,000 MWe of coal-fired or lignite-fired capacity during the same period.

With this burgeoning world coal utilization market, high technology coal systems from the U.S. can fill an extremely important need. Both India and Indonesia already impose tight emission control standards, and China is developing emission control standards. The opportunity for U.S. technology to play a major role in these markets is strongly dependent on successful domestic development, demonstration, and deployment. Further, continued improvements and innovations in these systems are necessary to maintain market superiority. Thus, a continuing Department of Energy (DOE) program for coal utilization Research, Development, and Demonstration is an important element in achieving market success.

Currently, the worldwide demand for capital for infrastructure projects is \$27 trillion. Seventy percent of this need is for electrification, of which 50 percent can be supplied by coal-fueled plants. Consequently, the demand for Clean Coal Technology (CCT) can reach \$500 billion annually over the next 20 years. Thus, the U.S. investment in CCT provides a significant potential for future sales and income.

Policy Considerations

The continued importance of coal and clean coal technology must be examined in the context of both domestic and international environmental and energy resource policies, as well as international transfer and export opportunities. In addition to the 1992 Energy Policy Act (EPACT), the six most important energy policy bases being emphasized by the Clinton Administration are:

- President's National Council for Sustainable Development and the Sustainable Development Action Strategy (in development).
- Development of the 1995 National Energy Policy Plan.
- President Clinton's Climate Change Action Plan, October 1993.
- President Clinton's Environmental Technologies Exports: Strategic Framework for U.S. Leadership Report, November 1993.
- Agenda 21, Programme of Action for Sustainable Development -- Rio Declaration on Environment and Development, June 3-14, 1992.
- The Clean Air Act Amendments of 1990 (CAAA), Titles I-VI (and associated Environmental Protection Agency rulemaking).

The President's National Council for Sustainable Development was established in mid-1993

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to develop a national sustainable development action strategy that will foster economic vitality. The Council consists of high-level representatives of several Federal departments, environmental interest groups, labor, and industry. Among the issues being reviewed by the Council are sustainable communities, eco-efficiency/pollution prevention, bio-diversity, transportation, energy, greenhouse gases, environmental technology and co-operation, trade, and environment.

This Council is to report its findings to the President by mid-1995, with an appropriate action strategy. Among the members of the Council, there are no spokespersons for coal and coal technology, with the exception of the Secretary of Energy. It is imperative that the important role of coal and coal technology be conveyed to this prestigious group.

Development of the 1995 National Energy Policy Plan, under the guidance of Secretary Hazel O'Leary, is another important policy planning activity. Again, the importance of low-cost, environmentally responsible electricity to the U.S. economy must be stressed, and the important role of coal in maintaining these goals is a critical element of a sustainable economy. This document should be considered as a contribution to that effort.

The other key policy bases were assessed in the context of the National Coal Council's earlier report, *Clean Coal Technology for Sustainable Development*. Summarizing the perspective given in that report:

- Domestic and/or international deployment of a range of Clean Coal Technologies (CCTs) and systems can help meet all of the President's key objectives in the Climate Change Action Plan and will address most of the key components of the President's planned implementation strategies by assisting in world electrification in an environmentally acceptable and benign manner, with an emphasis on pollution prevention. In addition, continued development, demonstration, and both domestic and international deployment of CCTs would create high-paying U.S. jobs and ensure the use of domestic resources.
- The National Coal Council continues to believe that expanded, controlled utilization of coal, particularly for electric power production, is in the nation's economic interest.

Environmental Considerations

A continuing emphasis on protection of the environment with an underlying concern for public health has focused on pollution prevention in new and developing technologies. The technologies reviewed in this report all reduce pollution and significantly decrease the negative environmental impacts of coal. An aim of all technology research and development should be pollution prevention through reduction of emissions and/or

increased energy efficiency. From a national standpoint, there are a number of Federal and state drivers for pollution prevention initiatives. These include the Pollution Prevention Act of 1990, the EPA pollution prevention leadership program, and a large number of state programs. The following comments illustrate the importance being placed on improving the environment through pollution prevention.

Based on the January 1993 results of the President's Commission on Environmental Quality that determined the value of applying total quality management principles to environmental quality in general and pollution prevention in particular, many pollution prevention initiatives not only reduce waste, but can be profitable projects in their own right. This is further strengthened by the increasing costs associated with managing wastes and by a decrease in the ability to landfill wastes. Focus from an emissions standpoint is shifting from impacts on air to other media as the Clean Air Act Amendments are implemented. Finally, due to the maturity of the U.S. environmental effort versus the rest of the world, coal utilization technology, featuring pollution prevention, will be developed in the U.S. and exported internationally. If clean coal technology provides the means of ensuring a cleaner environment and does not add large capital cost burdens to new projects and retrofits, the world will utilize U.S. experience in satisfying its energy needs.

A pollution prevention approach to business with total quality management emphasis from top management down will lead to an overall reduction in waste generated. This will make future permitting easier, decrease environmental impacts, improve coal's image, and increase overall profitability (either by a project's inherent profitability or by the reduction in long-term waste liabilities). After the easy waste generating solutions are applied, the next level of pollution prevention will require new technological approaches through more efficient systems, less polluting systems, and systems that convert more of the current waste into usable byproducts. The emphasis on new coal technology development is consistent with the overall environmental requirements in the U.S., both now and into the foreseeable future.

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CHAPTER II

THE VALUE OF COAL

The value of coal results from its worldwide abundance, its relatively low and stable cost, and its ability consistently to meet demand to fuel bulk electrical power on a steady and reliable basis. Domestically, coal also contributes to the national security since it is not subject to international political situations.

Coal use is subject to increasingly stringent environmental regulations which increase the cost of its use. As a result, the U.S. and other coal-using countries must balance the costs and benefits of restrictive regulations carefully in order to realize the full value of coal. With reasonable regulations, coal technology development and deployment can meet these environmental challenges once the initial financial challenges are addressed. These can be addressed through risk-sharing partnerships. With partnerships and mutual cooperation, clean coal technologies can provide power at reasonable cost.

The Coal Resource

The United States' stake in coal is undeniable. Proven U.S. coal reserves are the largest in the world, and coal is the most plentiful fossil energy resource in the United States. The importance of U.S. coal reserves to the indigenous and therefore secure energy resources of this economy are illustrated by these critical facts:

- Coal accounts for over 90 percent of total U.S. fossil energy reserves, making it the most abundant domestic energy source.
- In terms of oil equivalency, U.S. coal supplies are greater than either world oil or natural gas reserves.
- Domestic U.S. coal reserves could last for at least the next 250 years, whereas proven U.S. gas reserves represent about 50 years of supply.

Abundance and improving production efficiencies have translated into relatively low coal prices, critical to a growing and competitive economy. The average coal price has been more stable and consistently lower than oil or gas since 1973, when petroleum price first became a political issue. It should be noted that actual mine-site coal prices have declined in past years. In current dollars, the mine-mouth price of coal has dropped from an

average of \$24.50/ton in 1980 to \$21/ton in 1990.

Abundant low-cost coal is also critical to the economic success and energy security of many of the developing economies. Most obvious are China and India, growing economies that represent 40 percent of the world's population. They rely on coal for about 76 percent and 58 percent of their energy, respectively. Poland is also an example of a country heavily coal dependent, with coal meeting over 75 percent of its energy needs. Many coal dependent countries have limited alternative indigenous fuels and less capability than the United States to finance energy imports and energy alternatives.

Coal's Economic and Energy Security Contribution

Because of its low-cost coal resources, the United States is a world leader in hard coal production and exports. It is the world's largest producer of clean coal and second in exports to Australia.

In the years after the 1970s oil shocks, the U.S. turned to coal to provide a low-cost alternative to insecure imported oil. As a result, United States coal production and consumption/exports passed the 1 billion ton/year milestone in 1990. This achievement marked the end of a decade in which total coal production increased by 24 percent, from 829 million to 1.029 billion tons. At the same time, the industry became safer. During that time, domestic coal use jumped by over 27 percent, a record not equalled by any other fuel source in the United States. Coal's share of overall U.S. energy production increased from 29 percent to 33 percent.

This coal production translated into lower energy prices, lower energy imports, and increased energy exports. As production increased, productivity improved by almost 100 percent and coal prices fell. Moreover, the use of coal at competitive cost limited the ability of oil producers to raise their prices, an indirect effect that is seldom recognized.

The U.S. is already highly dependent on imported oil, importing about 8.5 million barrels per day, or over half of total oil consumed. Without intensive use of coal, volumes of oil imports would be even higher. Today, U.S. coal consumption displaces the equivalent of almost 10 million barrels of oil per day. This reliance on coal increases energy security, and coal reduces the nation's balance of payments deficit by over \$50 billion per year.

Coal further contributes to reducing the balance of payments deficit in the form of coal exports to approximately 40 countries. These exports, which help our trading partners diversify energy sources and reduce oil dependence, are valued at about \$4 billion.

The domestic and export value of annual coal production is \$21 billion. In addition to the

vital energy it provides and its direct economic benefits, coal is an important indirect contributor to the U.S. economy. According to a 1994 Pennsylvania State University study commissioned by the National Coal Association, direct and indirect benefits of coal to the U.S. economy include:

- Overall, the coal industry is responsible for more than \$88 billion of total sales in the economy, for the jobs of nearly 1.1 million workers, and for personal income of nearly \$50 billion.
- Coal production results in almost \$14 billion in personal income, wages, benefits, interest, and dividends.
- Each \$1 billion of U.S. coal production stimulates \$3.1 billion of production throughout the U.S. economy.
- For every direct job sustained in the coal industry, eleven indirect jobs are supported.

Coal production is concentrated regionally, and the industry's employment is therefore a substantial factor in local communities and states with active coal mines. In many mining areas throughout the U.S., the production of coal is the main economic force supporting a community's existence. In such locales, any significant downturn in coal production can lead to a major depression, even if the nation's economy at large is in generally good health.

Coal's Customers and Partners

The continued ability of coal to make this economic and national security contribution is linked to the ability of its customers -- electric utilities, industry, and the commercial/residential sector -- to find ways to continue to use coal in a cost-effective and environmentally acceptable manner. Meeting this challenge requires that coal suppliers and customers work as partners.

Coal and the Production of Electricity

Domestic electric utilities are the primary market for U.S. coal, consuming over 85 percent of U.S. coal production. The interdependence of coal and electricity is further evidenced by the fact that over 53 percent of the nation's electricity is generated from coal.

Used predominantly in base and intermediate load generation, low-cost coal has helped to hold down electricity prices and improved the competitiveness of U.S. manufactured goods. Coal also is a major contributor to the reliability of U.S. electricity supplies.

Though electricity is generated more efficiently than in times past, future fuel requirements for power generation are destined to increase because of steadily expanding uses for electricity. (As already noted, coal provides 53 percent of the energy used for generation of electricity.) In addition to conventional current uses, electricity is gradually displacing other energy forms in a wide range of applications. Twenty years ago, electricity met 25 percent of America's energy needs. According to the Department of Energy, the importance of electricity in the energy industry is projected to continue to grow over the next 15 years to 37 percent of end-use energy consumption.

U.S. electricity demand is expected to grow at an annual rate ranging from 1.3 percent to 1.5 percent between 1992 and the year 2010. Gross domestic product (GDP) growth during the same period is projected to be between 1.8 percent and 2.4 percent each year. Price-induced conservation, legislative and regulatory actions, and demand side management programs are expected to increase efficiency in the end-use applications of electricity. These factors would tend to slow down the phenomenal historical electric demand growth of 3.4 percent annually between 1970 and 1990.

Moderate costs, convenience of use, and low environmental impacts at the point of use are what drive the growing markets for electricity in the United States and the world. In addition, new uses for electricity are constantly being found. Where it once appeared that electricity demand would be saturated in the United States, new technologies, such as electro-technologies and electric vehicles, continue to have the potential to more than offset improved efficiencies in traditional electricity applications.

Electro-technologies are electric-powered end-use systems that improve manufacturing productivity in terms of energy consumed. Electro-technologies already have taken hold, for example, in the form of microwave ovens, microprocessors in computers, ultrasonic cleaning tools, and ultraviolet light for disinfection. Their growing potential is further illustrated in newly emerging products such as microwave clothes dryers and ultrasonic dishwashers.

The commercialization of electric vehicles would increase electricity demand directly. Electric vehicles are powered by batteries charged with electricity instead of fueled by oil. They therefore offer advantages in terms of environment and energy security. Their environmental advantage is that they produce absolutely no tail pipe emissions, which is critically important in areas with local smog problems. Furthermore, a "natural resource to end use" comparison of gasoline-powered vehicles (crude oil recovery, refining, transporting, and using) and electricity-powered vehicles (mining, transporting, generation of electricity, and using) reveals additional benefits from electric vehicles in both reduced environmental impacts and increased overall energy efficiency. From an energy security perspective, they can help to reduce oil imports significantly by providing an alternative energy source for part of the transportation sector, which consumes almost two-thirds of

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Coal in the Industrial and Commercial/Residential Sectors

Other sectors that use coal are the industrial, coking, and commercial/residential. Of these, growth in coal demand is likely to occur in the industrial sector, which today represents about 8 percent of U.S. coal consumption. The industrial sector uses coal to generate electricity, to raise steam for process use, to power foundries, and for cogeneration (combination use of heat and electricity). These industries, which include the chemical, food, metals, glass, stone, and paper industries, are growing. The Energy Information Administration (EIA) projects that industrial coal use (including cogeneration) will increase 1.8 percent annually between 1992 and 2010.

The coking coal sector requires coal with special chemical and physical characteristics that is used primarily in the production of steel. Coking coal represents about 4 percent of U.S. coal consumption and may fall to as little as 2 percent by 2010, according to EIA estimates. Nevertheless, use of coal in steel production continues to present environmental challenges that must be addressed as long as coal is a critical component of the processing of high quality steel.

The commercial and residential segments of coal demand are relatively small markets and are expected to remain so. Other energy and fuel sources (electricity, gas, and oil) have become more popular because they are more convenient to store and/or easier to use. Residential and commercial demand is expected to decline from 6 million tons in 1992 to about 5 million tons in 2010.

Coal's Challenge

The increasing use of coal to produce electricity and to fuel industrial and commercial applications has contributed collectively to sustained and long-term gross national product (GNP) growth. It has slowed the nation's growing dependence on imported energy with its accompanying fiscal, balance-of-payments, and national security implications. It has helped ensure the short-term adequacy of electricity supplies and stabilized electricity prices via a net decline in coal prices in real terms. The result is improved competitiveness of U.S. manufactured goods and an economic climate which promotes jobs

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and raises the standard of living.

In short, coal has been the right fuel, in the right place, at the right time. It has helped moderate prices when other forces in the economy were heading toward disarray. It has stabilized supply when more energy was needed to spur growth. It has provided an increasing degree of reliability and security when international political events exacerbated the danger of depending on foreign sources of energy.

Coal's competitiveness has slipped during the 1990s. This was due to several factors, including the higher capital cost per kilowatt of generating capacity, the relatively flat power demand, increasingly stringent regulations, and the need for mainly peaking rather than base load power facilities.

The challenge for coal is to complete the development of clean coal technologies, to assure cost competitiveness of these facilities, and to facilitate their widespread introduction and use. This must be accomplished by the time when base load power demand is projected to increase, shortly after the turn of the century. These new technologies must be technically ready and available for application.

The growing public belief in the importance of a cleaner environment in the U.S. makes it mandatory to develop cost-effective ways to utilize coal while reducing environmental impacts to meet societal goals. Deploying cleaner coal technologies as widely and quickly as possible is an important strategy in meeting the objective of continuing to realize the value of coal to the U.S. economy and reducing the environmental impact of its use. It is clear that new coal utilization technologies with higher efficiencies, lower emissions, and lower capital costs are necessary to help coal maintain its market share in the U.S.

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CHAPTER III

TECHNOLOGIES RELATED TO POWER GENERATION

A. Precombustion

Coal Cleaning

Coal is a heterogeneous substance which contains both organic and inorganic material. Carbon is the primary organic component of coal, and ash-forming mineral matter is the principal inorganic component. Coal cleaning consists of a number of processes that remove a significant amount of the ash-forming material from the coal in order to improve its characteristic for use as a fuel or feed stock. Coal cleaning has been practiced in the U.S. since the early 1900s. The technology was imported from Europe, where it had been developed and used well before that time. Historically, the driving forces for coal cleaning have been the desire for a better quality product and lower shipping costs. In more recent times, environmental limitations on sulfur emissions from coal utilization have driven coal cleaning technology toward increased removal of sulfur.

Physical Coal Cleaning

Technology Description

Physical coal cleaning (PCC) encompasses those technologies that remove inorganic and organic material from coal without altering its chemical nature. Since carbon has a lower specific gravity than most of the undesirable matter in the coal, PCC consists of various processes that utilize gravity separation techniques with water as the separation medium. In addition to gravity separation techniques, PCC processes also have been developed that are based on the different surface properties of coal and mineral matter and use that difference to cause the separation of the coal from the mineral matter. These processes are applied in series or parallel combinations to produce the desired quality of coal. The steps in the PCC process consist of characterization, sizing, separation, dewatering or drying, and storage/shipment.

Characterization consists of analyzing the constituents of the coal and testing it to determine its compatibility with the various cleaning processes, thereby establishing the process design parameters. A key test for determining the proper design criteria for the PCC processes is the float-sink test, in which different size components of the coal are subjected to liquids of different specific gravities.

Sizing consists of reducing the run-of-mine (ROM) coal to a particle size smaller than the maximum requirement for the final product. Typically, the ROM coal will be fed to a crusher or breaker, where the top size of the coal is reduced below the maximum size specification. The coal then is passed through screens and separated into streams that are sized to suit the various cleaning processes.

Separation is the step where the lower density coal is separated from the higher density ash material. Typically, the coal is floated in water or a mixture of water and a substance like magnetite that will increase the specific gravity of the mixture. Gravity will cause the coal stream to segregate into a stream of primarily pure coal particles, a stream of coal and ash particles (middlings), and a stream of primarily ash particles. The pure coal stream is taken as product and, depending on the complexity of the PCC facility, the middling and ash streams are subjected to further sizing and separation steps. Because of their density, the fine coal portion of these streams, particle sizes of 48 mesh (300 microns) or less, do not have sufficient settling velocity to allow them to be treated by gravity methods. As a result, they are subjected to further cleaning using surface property based techniques (for example, froth flotation, column flotation, and selective flocculation).

The dewatering and drying phase is necessary to remove the excess water gained during the PCC process. Dewatering reduces the moisture and weight of the final product and increases its heat content, thereby increasing its value as a fuel. Dewatering can be accomplished by mechanical means such as centrifuges, by vacuum filtration, and by thermal drying.

The various coal streams then are recombined and loaded for shipment to the customer or sent to storage facilities for shipment at a later time.

Detailed explanations of the PCC process and the equipment involved can be found in a number of references, some of which are listed at the end of this part of the report.

Development Status

PCC technology is available commercially throughout the U.S. and the world. The U.S. had 270 operating preparation plants in 1993, Canada had 14, and Mexico had 4. The majority (71 percent) of the U.S. plants were located in the Appalachian coal fields, where West Virginia had 66 and Pennsylvania had 60. Most of the remaining U.S. plants were located in the Illinois Basin (20 percent) and the West (4 percent).

Since 1989 the number of operating preparation plants has been reduced by 34 percent, and only 12 plants have been built since that time. The processing capacity of the plants ranged from 3,200 tons per hour (tph) to 40 tph, with a median capacity between 500 tph and 999 tph. The average capacity was 716 tph based on the 253 plants that reported

capacity data. Water-only technologies were used by 34 percent of the plants reporting and heavy-media systems by the remaining 66 percent.

Since the oil embargoes of the 1970s and the recent emphasis on sulfur dioxide emissions from coal burning sources, renewed interest has been focused on greater removal of ash and sulfur by PCC. This renewed interest has led to the further refinement and development of techniques that treat fine coal, 48 mesh (300 micron) or less. When the individual particle size of the coal is reduced, this allows for greater liberation of the sulfur and ash bearing mineral matter from the coal. Advanced gravity separation and surface chemistry based techniques can then be used to separate the fine coal further from the ash and sulfur material.

One such group of technologies (froth flotation and column flotation) employs air bubbles and additives to cause air bubbles injected into the coal and water slurry to capture the coal particle and float it to the surface of the mixture. The ash and sulfur mineral matter, which have an affinity for water, either remain suspended in the mixture or settle to the bottom. The additives have several discrete functions: to strengthen the air bubble/coal froth until it can be collected, to promote better contact between the bubble and the coal particle, and to modify the particle surface or mixture chemistry to enhance the separation process.

Another type of fine coal cleaning technology relies on additives such as diesel oil or heptane that have the ability to alter the surface properties of the coal particles. Coal particles are hydrophobic (repel water), and ash-forming mineral impurities are hydrophilic (attract water). When the additive is mixed into the coal-water stream and agitated, the coal particles agglomerate. The agglomerated coal particles can then be removed from the impurities using conventional separation techniques.

Environmental Performance

PCC has the capability to remove both ash and sulfur from coal, making it a cleaner fuel for combustion. Removing ash prior to combustion reduces particulate emissions during combustion. Removing sulfur before combustion similarly reduces the formation and emission of sulfur dioxide during combustion. PCC also increases the heat content per unit weight of the fuel, allowing it to burn more efficiently and thereby reducing the total level of all coal combustion-related emissions per unit of output (steam, electricity, coke, etc.).

The ability to remove sulfur from coal during PCC is limited by the forms of sulfur contained in the coal and the effectiveness of the technologies to separate mineral matter from the coal. Sulfur exists in three forms in coal: sulfate, pyritic, and organic. Sulfate is typically less than 0.1 percent by weight of the sulfur content of the coal. Sulfate is water soluble and can be removed during PCC. Pyritic sulfur is contained in the mineral

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matter of the coal and can constitute as much as 60 percent of the sulfur content of the coal. PCC can remove the pyritic sulfur to the same level that other mineral matter is removed. Organic sulfur is chemically bound to the carbon structure of the coal and cannot be removed unless that bond is broken. PCC cannot break this bond and therefore cannot remove organic sulfur. The potential for sulfur removal by PCC varies among the various regions of the country. A study of the characteristics and washability of 975 bituminous coal samples from the Eastern, Central and Western portions of the U.S. demonstrates that potential. The results of the study are shown in the following table.

**PYRITIC SULFUR REMOVAL POTENTIAL
OF PHYSICAL COAL CLEANING**

Characteristic	Eastern Region	Central Region	Western Region
Raw Sulfur, %	2.82	4.20	0.63
Pyritic Sulfur, %	1.84	2.68	0.18
SO ₂ , Lbs/MM Btu	4.50	7.10	1.10
SO ₂ Reduction, % @ 14 mesh & 1.60 sp. gr.	48	41	21
SO ₂ Reduction, % @ 14 mesh & 1.30 sp. gr.	61	55	26

SOURCE: U.S. Department of Energy, Sulfur and Ash Reduction Potential and Selected Chemical and Physical Properties of United States Coal, DOE/PETC/TR-91, Pittsburgh, Pennsylvania, June 1991.

For the vast majority of U.S. coals, PCC alone cannot produce a coal that will comply with either the particulate or sulfur emission limitations. Additional control will be required either during or after combustion. PCC of fine coal can result in mineral matter

reductions of over 90 percent. Subjecting the entire product stream to fine PCC, however, results in other undesirable consequences for the coal supplier and user. Reducing the entire coal product stream to particle sizes less than 48 mesh (300 micron) will result in severe dewatering, handling, and shipping problems. The finer coal particles with their increased surface area will retain more water, increasing their weight and lowering their heat content. Similarly, handling and transporting this wet, fine product will be prohibitive for most existing modes of transport and plant fuel receiving facilities. Thermally drying and mechanically forming larger particles from the fine coal (briquetting) adds significantly to the cost of the fuel.

Coal contains a number of trace elements that potentially could be required to be controlled under emission limitations. Chlorine and mercury emissions from coal combustion by power plants are addressed specifically in the 1990 Clean Air Act Amendments (CAAA). Most of these trace elements are removed to some extent during PCC. The specific substances that may be regulated and the impact that PCC has on the fate of those substances remain areas for scientific investigation (see also Chapter III, Part C, Hazardous Air Pollutants).

Commercial Impact

PCC is a widely used, mature commercial technology. In the most recent past, DOE and others have developed advanced fine coal cleaning technologies that now are being used or introduced into the commercial sector. The Custom Coal process is being demonstrated on a commercial scale under the DOE Clean Coal Technology Program. This process optimizes physical coal cleaning by taking maximum advantage of advanced proprietary designs of conventional hardware and the fine particles of coal which occur naturally during normal crushing and grinding. The commercial viability of this process is based on the ability to deliver Eastern high sulfur fuels processed to the same specifications as Eastern low sulfur coal in their market areas. Applications such as this, using advanced PCC, most likely will be limited to specific sites and circumstances. Although many of the clean coal technologies deployed in the future will have the flexibility to allow them to use lower grades of raw coal, advanced PCC may allow the current fleet of power stations to continue to operate competitively under tightened environmental constraints. Due to the phasing aspect of the CAAA and the ability to utilize emission allowances, sulfur removal by advanced PCC does not necessarily require delivery of "compliance" coal so long as the delivered cost of the fuel is priced competitively to the user. Thus, the use of PCC will be driven by the economic trade-offs between the alternative fuel sources and emission allowances available to the customer.

Development Needs

The DOE Fossil Energy (FE) program has made a significant contribution to the

development and advancement of PCC technology. Many of the processes developed by DOE FE are either in commercial practice or ready for commercial application. DOE should complete the current PCC effort in the CCT program.

The potential for further significant commercial applications of PCC technologies is somewhat limited. However, the relationship between hazardous air pollutant emissions and coal combustion remains to be defined in rulemaking by the EPA. The impact that PCC has on the fate of the trace elements in coal that may be required to be controlled as hazardous air pollutants is under investigation by DOE FE, and that work should continue. Chlorine and mercury are identified specifically in the Clean Air Act Amendments of 1990 in relation to coal combustion, and the DOE FE program should address their fate during PCC.

The alkali metal removal ability of PCC, particularly for sodium, will help reduce corrosion potential in combustion turbines. This may be useful in advanced combustion processes requiring combined cycles and/or high temperature turbines.

Many of the developing countries either produce or will rely on coal as the primary fuel to drive their development. As these economies grow, their impact on both the local and global environment will increase. DOE FE, with its demonstrated expertise in PCC, should promote the export of U.S. PCC technologies to these developing countries. DOE FE has done this successfully in Poland, and that effort should continue on a worldwide basis.

Chemical Coal Cleaning

Technology Description

Chemical coal cleaning (CCC) is aimed at removing the pyritic and organic sulfur contained in coal. Organic sulfur removal requires the sulfur-carbon bond to be broken in some manner and the sulfur to be captured and removed. The technology can be described broadly as reducing the coal stream to a fine size that can be subject to a desulfurization agent at various temperatures and pressures.

For example, the TRW Molten-Caustic-Leaching (MCL) process, which is one of the more fully developed technologies, utilizes a melt of sodium hydroxide or mixtures of sodium and potassium hydroxides at reaction temperatures of 600°F to 780°F. In the MCL process, the feed coal is mixed with anhydrous sodium hydroxide, heated, and subjected to a seven-stage process, including countercurrent water washing, filtration and centrifugation, and, finally, a three-stage countercurrent acid washing and centrifugation. Tests of Pittsburgh No. 8 coal yielded a product coal with 0.4 percent sulfur and 0.15 percent ash content which results in a sulfur reduction of more than 95 percent.

Development Status

No CCC process has been demonstrated at a size greater than 20 tph. The complexity of the processes, high temperature reactions, and expensive reagent costs have shown that the processes under development are not economically viable. As a result, development beyond the bench or pilot scale has not taken place.

Environmental Performance

CCC has the potential to produce compliance coals from most higher sulfur coals. Because the processes involve reagents to treat the coal, environmental controls on the process itself are a major concern and must be evaluated thoroughly.

Commercial Impact

Based on the current state of development of these processes and their lack of economic viability, it is doubtful that CCC will have significant commercial impact in the foreseeable future.

Development Needs

DOE FE has conducted a well-designed program to identify and develop promising CCC processes. No promising commercial processes have emerged. In light of these circumstances, DOE FE should re-evaluate its current CCC program, particularly as it relates to hazardous air pollutant control and alkali metal (sodium) reduction. If the results are unfavorable, it is recommended that the remaining funds be transferred to more promising coal utilization programs.

Biological Coal Cleaning

Technology Description

Biological coal cleaning involves the utilization of bacteria and fungi to reduce the pyritic, sulfate, and organic sulfur in processed coal. Biological systems have been applied in treatment of both liquid and solid waste streams from the pharmaceutical and food processing industries for many years. The attempt to utilize bacteria to reduce sulfur in coal was reported in 1947. The work involved the isolation of thiobacillus ferredoxins from acid mine drainage.

Sulfur in coal is present primarily either in the metallic sulfide form (pyritic sulfur) or bonded in the organic carbon matrix. Iron pyrites have a very definite mineral and chemical composition. Some iron pyrites in higher sulfur coal seams may be concentrated

in large particles and are liberated easily by crushing. This crushing exposes large amounts of high density pyrites that can be washed out in coal preparation plants. Further crushing to expose these fine particles produces only minimal results. The microbial removal of pyritic sulfur is centered on the removal of these very fine grains of sulfur.

The organic sulfur is bound in the organic carbon matrix and is very difficult to detect and remove. Detecting organic sulfur compounds has been a major part of the research work. Since the ASTM methods analyze for pyritic and sulfate sulfur, the organic sulfur is calculated by difference. Due to the uncertainty of the nature of the organic sulfur compounds within the coal structure, most researchers have elected to work with model compounds such as dibenzothiophene (DBT). Since coal has such complex organic structures, the theory is that if a process reacts with DBT, it should work on coal.

Various methods of microbial contact have shown promise. Heap leaching, slurry mixtures, and impoundments are the basic methods used to contact the water-borne bacteria and fungi with the sulfur in the coal particles.

- *Heap leaching:* The heap leaching process introduces iron-eating and sulfur-eating bacteria to a "heap" of coal through controlled sprays. The bacteria increase the rate at which iron pyrite oxidizes. In recent joint venture tests, the Pittsburgh Energy Technology Center and the Bureau of Mines have utilized bacteria successfully to reduce the pyrites as much as 50 percent. The bacteria, thiobacillus ferrodoxins, are applied to the coal. The bacteria accelerate the normally slow oxidation process of the pyrites. The oxidized pyrites form soluble iron sulfate. The soluble iron sulfate then is washed from the heap by flushing with water. The water is treated and recycled. The major problem with heap leaching is the extended amount of time and space required for the bacteria to react with the pyrites. Even the accelerated reaction takes several days to reduce the pyrites to soluble sulfur compounds.

- *Slurry mixtures:* Several years ago, coal slurry pipelines were being promoted as an alternative to rail and barge shipments for the long-distance transportation of coal. There was a lot of work done with infusing bacteria in the transporting medium to reduce sulfur during the long journey to the customer. Special consideration would have to be given to the high acidity that would develop as the bacteria attacked the sulfur inorganic compounds. Special piping or inert pipe liners would be necessary to eliminate corrosion. Coal must be crushed prior to being transported by water. This crushing operation would expose additional surface area to the bacteria and further enhance the sulfur removal process. Travel times of up to two weeks were anticipated, which is ample time for the sulfur removal process to work. At the end of the pipeline, the water and coal would be separated. The coal would be washed, and the water from the pipeline and the water from the washing process would be treated and returned to the pipeline or utilized as process water. The drawback to this process is that there were no long-distance pipelines built.

The only working coal pipeline today is in Arizona. This pipeline is 274 miles long and transports coal from the Black Mesa Mine to a power plant owned by Southern California Edison. There are no current plans to introduce bacteria for sulfur removal.

- *Impoundments:* Impoundments are used as contact tanks for the water-borne bacteria to react with the organic and inorganic sulfur in the coal. This process is similar in nature to heap leaching, except that the coal can be exposed to heavier concentrations of bacteria cultures. Also, the coal can be crushed more finely, thus exposing more surface area to the bacteria. Water can be recirculated and treated to the optimum conditions for bacteria growth. The major problem that plagues this process is the amount of time and land area required for adequate contact and sulfur reduction.

DOE allocated significant research grants to study the microbial reduction of organic sulfur in coal. Research to date has not been encouraging. The emphasis has shifted to pyritic removal by microbial techniques since this has shown the most promise. Cleaning of raw coal in conjunction with biological removal of sulfur has been able to remove more than 50 percent of the total sulfur.

Development Status

Problems associated with microbial sulfur removal are time, mutation, space, and cost. Most large coal mines produce over 500,000 tons of coal per year. The current technology for microbial sulfur removal is measured in days. There are no full-scale plants for this technology, and most bench test and pilot plants require 15 to 30 days to remove the sulfur. The required area to permit this type of retention time is quite large.

Environmental Performance

The ability to remove both pyritic and organic sulfur from coal would be a very desirable result if it could be done economically. Unfortunately, this does not appear to be the case. Also, it does not appear that biological sulfur removal will become economically viable in the near future; thus, the potential for any commercial impact by this technology is very small or zero.

Biological treatment processes produce a waste water effluent that requires treatment using existing technology. This extra step obviously will increase the final cost of the product.

Development Needs

The DOE FE R&D program has made a creditable attempt to identify promising techniques to use biological means to remove both pyritic and organic sulfur. Unfortunately, no technically or economically viable means has evolved for the near term. Basic research

should be continued, looking for novel approaches that would result in significant cost reductions. Also, emphasis should be focused on understanding the chemistry and improving the overall kinetics (reaction time) of the processes and developing new agents, specifically ones that would duplicate those found in nature.

New Fuel Forms

New fuel forms encompass a number of processes that change the physical and chemical characteristics of coal before it is used as a fuel. The changes considered here consist of low rank coal beneficiation, micronized coal, and coal liquid slurries.

Low Rank Coal Beneficiation

Technology Description

Economics and environmental considerations have increased the production of low rank coals (LRC) significantly over the last 15 years (from 111.5 million tons in 1977 to 342.2 million tons in 1992). Sub-bituminous coal and lignite represent 47.5 percent of the demonstrated coal reserve base of the U.S. Sub-bituminous coal typically can be characterized as having a low sulfur content (1.0 percent or less); low heat content (8,300 Btu/lb to 11,500 Btu/lb on a moisture-free, mineral-free basis); and high moisture content (25 percent to 35 percent). Based on the magnitude of the demand for LRC and its characteristics, it is readily apparent that a significant amount of water was transported in the LRC that had to be evaporated during combustion, and the amount of material that had to be handled was significantly greater than for bituminous coals. Facilities that were not designed originally to burn LRC can experience significant coal handling and operational problems leading to reduced generating capacity. Technologies designed to beneficiate the LRC by reducing moisture content and thereby increasing heat content are under active development.

LRC beneficiation processes can be characterized by the temperature at which they operate and by the changes in the coal structure that may occur during processing. Evaporative processes generally utilize temperatures below 400°F and are similar in many instances to the thermal drying techniques commonly used on bituminous coals. The drying medium generally is air, but hot oil also is used. Processes that subject the LRC to temperatures above 400°F but less than 900°F and above atmospheric pressure effectively advance the coalification process, not only by driving off moisture, but also by converting oxygen in the LRC to CO₂. LRC beneficiation processes that operate above 900°F are considered pyrolysis processes, and they significantly change the moisture and the volatile content of the LRC. Brief descriptions of LRC beneficiation processes currently under development follow. These are meant to be, rather than a comprehensive listing, examples of some of the processes that are further along in their development.

Development Status

A number of LRC processes are in commercial practice. A Western utility uses an entrained reactor to dry lignite which is fed to an electric power generating plant. A mill-drying process has become standard practice for drying brown coal in Victoria, Australia. A steam fluid-bed drying process to reduce the water content of brown coal from 60 percent to 15 percent is being installed at a plant operated by the State Electricity Commission of Victoria, Australia.

Several U.S. LRC beneficiation processes are being demonstrated at the pilot and near commercial scale. The Syncoal Advanced Coal Conversion Process and the ENCOAL Mild Coal Gasification Project are being demonstrated at the commercial scale under the DOE Clean Coal Technology Program. Many of the demonstrations have dried the LRC successfully to specifications, but unwanted quality characteristics have occurred. The low temperature evaporative processes have shown considerable size degradation after drying. In addition, the dried product has exhibited a tendency to reabsorb the moisture and an increased tendency to combust spontaneously. These problems are being addressed by re-humidifying the coal or by applying a coating to the dried coal. The medium-temperature dried products do not exhibit the moisture reabsorption but do experience the size degradation problems. The Carbontech Hot Oil Drying process uses oil as the drying medium, and some of the oil is absorbed, stabilizing the dried coal and increasing its heat content. Several of the pyrolysis processes formed briquettes to avoid the size degradation problems.

Environmental Performance

LRCs have the environmental advantage of lower sulfur but the disadvantage of causing more fuel to be consumed per unit of energy because of the need to evaporate the excess moisture during combustion. Beneficiated LRC will reduce this problem and may eliminate it, depending on the process utilized. Thus, overall environmental emissions should be lower than for conventional bituminous coals. In addition, beneficiated LRC can eliminate many of the operating constraints the LRC can present to facilities that were designed for bituminous coals.

Commercial Impact

The potential commercial impact of beneficiated LRC is limited only by its ability to compete in the marketplace with other types of coal. The cost of the beneficiated coal will depend on the economics of the particular process and the transportation charges associated with delivering it to the customer. It remains to be seen whether, for rate purposes, the railroad companies will treat beneficiated coal as other coal is treated or as a specialized product requiring a higher rate.

The Electric Power Research Institute recently performed a market assessment of beneficiated LRCs. The assessment considered the AMAX Coal Dryer, Carbontech hot oil drying, Syncoal ACCP, ENCOAL Mild Gasification Process, and K-Fuels Process. The assessment indicated that if the beneficiated LRCs can be produced for less than \$20/ton (\$0.85/MBtu), a utility market of 25 MTPY would result. If the price was decreased to \$18/ton (\$0.75/MBtu), this market would increase to 50 MTPY.

In addition, EPRI used its Coal Quality Impact Model to determine the impacts of three LRC beneficiation processes on the cost of producing power from three different steam electric generating units. The three LRC beneficiation processes analyzed were the AMAX Coal Dryer, Syncoal ACCP, and ENCOAL Process. The three types of units were a 180 MW wall-fired unit, a 560 MW cyclone-fired unit, and a 560 MW tangentially fired unit. The analysis assumed an unprocessed LRC cost of \$4.00/ton and actual transportation rates to the various units. The analysis calculated the cost at which it would be more economical to purchase the beneficiated LRC rather than the unprocessed LRC. The results of the analysis show break-even costs ranging from \$0.46/MBtu to \$0.52/MBtu for the cyclone unit; \$0.66/MBtu to \$0.79/MBtu for the wall-fired unit; and \$0.91/MBtu to \$0.99/MBtu for the tangential fuel unit.

Development Needs

LRC beneficiation is being demonstrated at both pilot and commercial scale. The DOE CCT Program is supporting LRC beneficiation processes. DOE FE should complete its present LRC beneficiation program.

Micronized Coal

Technology Description

Micronized coal typically refers to a coal stream in which 80 percent of the particles are less than 44 microns in size and will pass through a 325 mesh screen. Pulverized coal typically has a particle size distribution in which only 60 percent of the particles are less than 44 microns. Micronized coal can be prepared by segregating fine coal produced in typical coal cleaning operations or by direct size reduction through a mill or pulverizer designed to produce a micronized coal stream. Interest in this technology grew from the desire to find replacement fuels for oil and gas when their costs increased significantly. The envisioned applications were substitution in oil/gas-fired boilers, unit start-up, and low load flame stabilization. More recently, micronized coal is being evaluated as a source of fuel for staged combustion or reburning to reduce NO_x emissions.

Micronized coal exhibits large surface area relative to the weight of the particles. As a result, during combustion a micronized coal stream has a flame pattern that closely

resembles an oil flame. A comparison of coal test data with oil test data indicates that micronized coal with 75 percent <325 mesh grind closely approaches the heat flux and furnace exit gas temperatures for firing No. 6 oil. A comparison of several coal firing techniques (chain grate stoker, overfeed stoker, bubbling fluidized bed combustion) revealed that for NO_x emissions, combustion efficiency, excess air levels, and dry flue gas losses, a micronized coal firing system met or exceeded the performance of the other systems.

Micronized coal can be produced from fine coal cleaning processes during physical coal cleaning. Processes such as froth flotation can produce minus 44 micron material that can be dried sufficiently to use as a micronized coal fuel. Handling and transport of the fuel will require special arrangements such as enclosed cars and pneumatic loading and unloading.

Micronized coal also can be produced by direct grinding or pulverizing of the coal at its point of use. The standard methods of comminution can be utilized (pulverizers, ball mills, etc.), but a relatively new approach that has been developed uses attrition mills. In attrition mills, the coal feed is subjected to a spinning motion in the mill induced by rotors equipped with abrasive hammers or by a rotating impeller followed by a classifier that recirculates oversized materials. Depending on the type of mill, the coal is reduced in size by impact on the sides of the mill, by impacting with other coal particles (attrition), and by impacting on the rotors/hammers of the impeller. The energy required to operate this type of mill is typically less than 1 percent of the fuel input to the boiler.

Development Status

Micronized coal is being used commercially in both the U.S. and Europe. The majority of applications are in industrial settings. Two commercial utility applications have been installed in the U.S. The Duke Power Company installed a MicroFuel™ System on the 600 MW Unit No. 5 at the Cliffside Generating Station to investigate micronized coal as a replacement fuel for No. 2 oil. The test indicated that micronized coal could be utilized to decrease the amount of oil required during start-up and low load operation.

Tests were run at The Greenbrier (White Sulphur Springs, West Virginia) during the summer of 1994 coupling a diesel engine in a combined cycle with a micronized coal-fired boiler. The burner for this application was developed by Babcock & Wilcox, and the test was run in conjunction with Wartsila Diesel in Annapolis, Maryland. The micronizer and fuel handling equipment was provided by TCS. The tests verified that it is possible to place a diesel engine in front of a coal-fired boiler so that it is now practical to retrofit an existing coal-fired boiler system to produce electricity without modifying the steam portion of the boiler. Exhaust from the engine is used as part of the combustion air for the boiler. The fuel in the boiler can be natural gas, light fuel oil, or heavy fuel oil.

The City of Rochelle, Illinois, located 75 miles west of Chicago, has installed a TCS Micronized Coal System on its 11.5 MW electric/steam cogeneration facility. The two boilers originally were designed to fire both gas and coal, but they were converted to gas alone for environmental compliance reasons. The micronized coal installation includes new baghouses and coal and limestone feeding and storage facilities. Tests will be conducted while firing both coal and limestone that have been micronized in a TCS System.

Environmental Performance

Micronized coal as a replacement for gas or oil combustion will require additional particulate control due to the ash content of the coal. Sulfur dioxide controls also may be required, depending on the sulfur content of the coal and the emission limitations. Nitrogen oxide emissions may be higher than for gas or oil firing, but micronized coal firing, if used in a staged combustion or reburning arrangement, may effectively reduce the total NO_x emissions from a furnace. The combined firing of coal and limestone that are micronized has the potential to reduce SO₂ emissions.

Commercial Impact

Micronized coal technology is commercially available for industrial applications, but its use is limited by the price differential between fuels and the environmental considerations for using coal. In utility applications, micronized coal has been demonstrated to have the ability to reduce or eliminate oil consumption during start-up and low load operation. Co-firing of micronized coal to reduce No_x emissions remains to be demonstrated, but it could have a major impact in hard-to-control situations such as with cyclone-fired boilers.

Development Needs

Micronized coal has been demonstrated adequately in the industrial sector as a replacement for oil or gas and as an alternate fuel for utility start-up and low load operations. Use of micronized coal in staged combustion or reburning applications should be emphasized.

Coal-Liquid Slurries

Technology Description

Coal-liquid slurry technology has matured and, from a technical standpoint, is a viable option as a substitute for oil in power plants. Significant development work on slurry stabilization and burner technology has been completed successfully. This technology also is applicable for utilizing coal fines from waste ponds. Coal-methanol slurry uses methanol as the transporting medium. The slurry is 45 percent to 50 percent coal by weight with a top size of 28 mesh (size of coarse sand). Coal-liquid carbon dioxide is another

technology that employs carbon dioxide liquid to transport the coal. This is a dense slurry that contains 75 percent to 85 percent coal at minus 200 mesh. Coal-oil slurry uses heavy oil as the transporting medium but contains only 30 percent to 50 percent coal.

Depending on the process, the coal is ground, beneficiated, partially dried, and sent to tanks for mixing. Chemicals are added to stabilize and produce the desired flow characteristics in the fuel. Other additives such as dispersant, defoamers, and bacteria-inhibiting agents are added. The additives are less than 0.5 percent, by weight, of the total mixture. The coal-liquid slurries can be shipped in pipelines, stored, transported in rail cars or ships, and burned without settling.

Development Status

Coal-water slurry technology was developed into a commercial technology during the period 1975 to 1985. Following the oil embargo and high coal prices in the 1970s, coal-water slurries were investigated and technologically refined to the point they could be handled and fired in some industrial and utility boilers in place of No. 6 fuel oil. With modifications to the boilers, the coal-water slurry could be fired with little difficulty. With the decline in oil prices, however, this technology was never able to compete on a price per million Btu basis.

Today the Japanese are manufacturing coal-water slurry on the Chinese mainland and transporting it by pipeline to the Rizhao Port for shipment to Japan. The slurry consists of 70 percent coal and 30 percent water with less than 0.5 percent stabilizing additives. The 12,700 Btu, 9 percent ash Chinese coal is wet-ground in ball mills with water. The slurry is pumped via pipeline over one mile to a facility for loading on board small vessels. The loading rate is about 1,000 tph. The coal is shipped to Japan and burned in a small industrial boiler.

Currently, Japan COM, Ltd., annually produces about 500,000 tons of coal-water slurry and pumps it over six miles to the Nakaso Power Station. The slurry is burned in a 600 MW unit located at the Joban Joint Power Co., Ltd. The slurry is a combination of 50 percent coal-water slurry, 30 percent coal, and 20 percent oil.

In the United States, the interest in coal-water slurry technology is concentrated on utilizing waste coal (pond fines). Pond fines and fine coal from operating preparation plants are being used to make coal-water slurries for injection in industrial and utility boilers.

A Pennsylvania utility currently is testing a 50/50 coal-water slurry in a small utility boiler. This unit is a 330,000 lbs. steam/hr boiler producing 32 MW. A side stream from the preparation plant is used to generate minus 100 mesh coal fines to slurry with water

for injection in the lower three burners of the unit. It is planned to go to 100 percent coal-water slurry in the near future. The possible use of waste coal ponds to recover fine coal for the coal-water slurry is being explored. A side benefit to the injection of coal-water slurry is NO_x reduction. The flame is several hundred degrees cooler than for coal alone, thus decreasing the formation of thermal NO_x .

A consortium of utilities is investigating the possibility of using a coal-water slurry as a reburning fuel to lower NO_x . By injecting coal-water slurry higher in the furnace, the thermal NO_x is reduced. Utilization of run-of-mine coal fines is a key element of the economic viability of this venture.

Environmental Performance

Depending on the ash and sulfur content of the coal used, the emissions from the combustion of the slurry could require the addition of control equipment. Where the slurry is being used to substitute for liquid or gaseous fuels, additional particulate removal and, potentially, sulfur removal equipment will be required. As described above, the addition of a liquid into the combustion zone can have the positive effect of lowering the flame temperature and decreasing the formation of NO_x .

Commercial Impact

Production of coal-liquid slurries is a commercial technology, and some slurries can be substituted for oil in industrial and utility boilers. Currently, cost is the major deterrent to their widespread use. As long as oil remains at its current low price, coal-liquid slurries will be used only for specialty markets such as coal-waste-water slurries. Coal-water slurries may gain wider acceptance if a cheap source of coal waste is located near a power-producing facility or substantial thermal NO_x reduction can be obtained by firing slurry.

Development Needs

The DOE FE Program and industry have been successful in developing coal-liquid slurry technology to commercial status. Although major demonstration programs may not be necessary, DOE should continue to look at additional coal wastes (for example, gob piles) for coal-slurry utilization. Also, further development of its use as an NO_x reduction technique has merit.

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B. Combustion

Advanced Pulverized Coal-Fired Boilers

Technology Description

Pulverized Coal-Fired (PCF) boilers have been in use since the early 1900s and are currently the most widely accepted technology for coal-fired electric generation technology. In a PCF boiler, coal is ground (pulverized) to a very fine particle size (typically 70 percent less than 200 mesh) and blown into burners located in the lower portion of a furnace, where combustion occurs. Primary air conveys the pulverized coal directly to the burners at a rate set by the combustion control based on the steam generation requirements. Secondary air is supplied by forced draft fans. All or most of the secondary air is supplied to the windboxes enclosing the burners. A portion of the secondary air may be diverted from the burners to ports located above the burners for NO_x control.

Combustion occurs in the furnace at a temperature in the range of 3000°F. The combustion process continues as the gases and unburned fuel move away from the burners and up the furnace. The furnace walls typically are constructed of water-cooled tubing. Final burnout of the char depends on the coal properties, particle fineness, excess air, air-fuel mixing, and thermal environment. The products of combustion exit the furnace and enter the convection pass, which contains most of the heat-transfer surface, after being sufficiently cooled to minimize convection surface fouling. Typically, the combustion byproducts then flow through an air preheater and then to the back-end cleanup systems, including an electrostatic precipitator or bag filter, scrubber, and stack. In order to meet current New Source Performance Standards (NSPS) for sulfur dioxide control, new pulverized coal-fired boilers installed in the United States require a flue gas desulfurization (FGD) system for removal of sulfur dioxide.

Most conventional PCF boiler systems currently in operation use subcritical pressure (usually 2400 psi) steam cycles with superheat steam and single reheat steam temperatures of 1000°F to 1025°F. This results in higher heating value (HHV) net thermal efficiencies in the range of 33 percent to 35 percent. A smaller number of units operate with supercritical pressure cycles (~3600 psi), which increases the efficiency to about 37 percent. Control systems are added to the basic power system design to meet emission requirements.

Technology advances and increasing environmental concerns have led to renewed interest

in advanced PCF boiler system designs. These advanced systems combine ultra high temperature and pressure steam cycles with an integrated power/environmental system design approach which optimizes the use of advanced SO₂ and NO_x control technologies to minimize emissions and significantly increase cycle efficiency.

Proposed designs use main steam pressure of 4100 psia to 6000 psia, double reheat cycle configuration, and steam temperature of 1075°F to 1100°F (some as high as 1200°F). Combined with optimized heat recovery, these systems promise HHV thermal cycle efficiencies in the range of 40 percent to 42 percent or higher (heat rate of 8,000 Btu/kWh to 8,500 Btu/kWh) with low SO₂ and NO_x emissions. Building upon current power system designs, key elements include advanced high temperature materials, improved thermal-hydraulic design, optimized heat recovery, low-NO_x combustion systems (see below), and advanced postcombustion flue gas desulfurization and NO_x control systems (see Chapter III, Part C).

Development Status

PCF boilers generally are considered to be mature, with thousands of boilers currently in use throughout the world. Recently offered PCF boilers tend to have conservative designs to allow for fuel flexibility. This conservative approach is reflected in the larger furnace size. In addition, manufacturers of pulverized coal-fired boilers are attempting to offer standardized designs to reduce the capital costs, maximum use of modularity to reduce the construction time, and capability for cyclic operation.

As with other technologies, significant improvement of PCF boilers in the future will be in the area of control systems. Improvements in the sophistication of control systems provide the opportunity to better match the air to the fuel, as well as control of coal fineness, boiler water chemistry, burner management systems, circuitry flow, diagnostics, and soot blowing to enhance the reliability and efficiency of steam generators.

Other developments in PCF boilers are expected in the area of compatibility with advanced steam cycles (ultra high pressure and temperature designs) and integration into advanced combustion systems to maximize the efficiency and minimize the overall plant emissions. Efforts have been underway to increase the steam temperatures to as high as 1100°F, as opposed to the current norm of 1000°F to 1025°F.

Environmental Performance

Emissions from most PCF boilers can easily meet levels at current standards. NO_x emissions from PCF boilers can be reduced by modifications to the burner and combustion zone, through staged combustion, or through reburning technology. (These technologies and their emission control capabilities are discussed later in this section and also in Part

C of this chapter.) Further NO_x emission reduction requires the addition of postcombustion "de- NO_x " technologies. Sulfur emissions can be controlled by coal cleaning, furnace sorbent injection, slagging combustors, or postcombustion cleanup.

Commercial Impact

Pulverized Coal-Fired boilers are perceived to be the lowest-risk approach to using most bituminous and sub-bituminous coals for electric power generation. However, the advantages of other technologies, especially fluidized bed combustion, become significant as the fuel quality declines. PCF boilers are used most often as the base-line in the evaluation of other coal-fired technologies. Increased interest in burning low-quality fuels, decreasing emissions, and improving cycle efficiencies are expected to result in higher market share for clean coal technologies in the future. Advanced PFC boiler designs offer this technology the potential to achieve high cycle efficiencies in excess of 40 percent (HHV) with low emissions.

Development Needs

Relatively low fuel cost and the more mature state of PCF boilers have minimized the recent need for major R&D efforts. However, with renewed emphasis on higher efficiency systems and reduced emissions, continued fundamental research into the chemistry of coal combustion, improvements in burner design, development of advanced materials of construction, and integration into advanced integrated low emission high efficiency cycles are the primary needs associated with PCF boilers. Hazardous air pollutant emissions need to be quantified. It also will be critically important to demonstrate any new technologies (for example, new high temperature materials) in large-scale commercial units, through efforts such as the Low Emission Boiler System (LEBS) Program, in order to gain rapid industry acceptance. In addition, the opportunities for co-firing and biomass combustion may warrant further consideration.

Low- NO_x Burners

Technology Description

The formation of NO_x during combustion arises from the nitrogen in the fuel and the nitrogen in the air. The conversion of the nitrogen into NO_x increases with higher temperature and excess air levels. The combustion efficiency (carbon utilization) also is strongly dependent on the combustion temperature and stoichiometry. Until the 1960s, most burners utilized in pulverized coal-fired boilers were designed to operate with high turbulence, optimum stoichiometry, and high temperatures. This resulted in formation of relatively high levels of uncontrolled NO_x emissions, typically on the order of 1.0 lb/MBtu.

In order to comply with limits established by the Clean Air Act and its amendments, low-NO_x burners (LNBs) were developed for pulverized coal-fired boilers to reduce the formation of NO_x during combustion.

The basic design principle of most low-NO_x burners is staged combustion, by which the coal is burned with reduced turbulence in order to reduce the combustion temperature and available air during the initial combustion stages. Fuel is concentrated in the center of the flame pattern, creating a fuel-rich core. A secondary-air envelope is formed around the outer portion of the flame to complete the combustion process at a peak temperature of about 2800°F.

Development Status

Enactment of the Clean Air Act of 1976 resulted in the development of first generation low-NO_x burners to limit NO_x emissions to less than 0.6 lb/MBtu. Further NO_x reductions associated with the Clean Air Act Amendments of 1990 have resulted in extensive retrofits of advanced low-NO_x burners which can reduce emissions from baseline conditions to approximately half that value. Over 2,000 LNBs have been installed in over 100 utility boilers in the U.S. to date. They are offered with full commercial guarantees.

Environmental Performance

Low-NO_x burners are offered currently with NO_x emission guarantees in the range of 0.45 lb/MBtu to 0.5 lb/MBtu for existing boilers. Further reductions in NO_x emissions require additional advanced techniques such as over-fire air. Most installations have met the guaranteed emissions. However, in general, the loss on ignition (unburned carbon in the ash) has increased due to the installation of low-NO_x burners.

Commercial Impact

Low-NO_x burners have become a standard component of new PCF boilers. In addition, the extensive LNB retrofitting into existing boilers now underway is expected to continue as utilities develop their strategies to comply with the Clean Air Act Amendments of 1990.

Development Needs

Current research and development needs for low-NO_x burners lie primarily with the need for improved carbon utilization, especially for low volatile coals. Future reductions in NO_x emissions from pulverized coal-fired boilers utilizing low-NO_x burners are expected to arise more from furnace modifications associated with over-fire air and reburning technologies than from significant improvements in low-NO_x burners themselves.

Additional NO_x Reduction Techniques

Technology Description

NO_x emissions from conventional pulverized coal-fired boilers using LNBs can be reduced further by means of additional furnace modifications beyond installation of LNBs. These modifications include over-fire air and reburning.

Over-Fire Air

Over-fire air (OFA) systems are a mechanism to further reduce NO_x formation in conventional PCF boilers. In this design, the introduction of air into the furnace is staged in order to create a delay in the mixing of the fuel and air in the furnace. This staging lowers the combustion temperature and reduces the amount of oxygen available to the fuel-bound nitrogen. The burners are fired in a sub-stoichiometric condition, and 10 percent to 20 percent of the total combustion air is diverted to ports located above the combustion zone. Advanced over-fire air systems use separate ducts, air-flow measurement devices, and dampers to control accurately the amount of over-fire air.

Fifty percent to 70 percent reductions in NO_x emissions can be achieved when combining low-NO_x burners with OFA ports. While boiler companies are offering OFA ports with commercial guarantees, there are commercial concerns about long-term furnace corrosion when utilizing OFA designs. Manufacturers have sold low-NO_x burners in combination with OFA systems with NO_x guarantees as low as 0.33 lbs/MBtu.

Reburning

The temperature in the mid-section of most PCF boilers is in the regime of 2000°F to 2400°F. Nitrogen oxide is relatively unstable at this temperature and therefore can be destroyed by the introduction of a reducing agent. In reburning technology, a small percentage of the combustion fuel is injected through ports in the upper portion of the furnace to convert the NO_x to elemental nitrogen. Additional air then is fed above those ports to effect the burnout of the fuel. This design approach results in approximately 50 percent reduction in the NO_x entering the reburning process. Reburning can be accomplished with natural gas, oil, coal, or, potentially, coal-water slurry as the reburning fuel.

Reburn technology may be especially attractive for the relatively large existing population (725,000 MWe) of wet bottom boilers, particularly cyclone furnace boilers. In these systems, coal is burned at very high temperature, melting and collecting most of the coal ash as a liquid slag, which is removed (tapped) from the furnace bottom. Reburn technology offers the potential to reduce the inherently high NO_x emissions (typically 1.5

lb/MBtu to 2.0 lb/MBtu) in these units without significantly changing the cyclone or wet furnace operation.

Using pulverized coal as the reburning fuel offers the operating advantage of a lower cost fuel than oil or natural gas. Coal reburning was tested on a 110 MWe cyclone-fired boiler as a Clean Coal Technology Demonstration Project. NO_x reductions up to 60 percent were reported. Coal reburning is being offered commercially for NO_x control. However, coal reburning may require a substantial increase in the furnace residence time and may be economically and technically feasible only for a select group of boilers.

Development Status

Over-fire air has been tested extensively and is offered as a commercial technology with full guarantees. Gas reburning has been demonstrated in a 172 MWe pulverized coal-fired boiler as part of the Clean Coal Technology Program. When installed in combination with low-NO_x burners, NO_x reductions on the order of 70 percent have been reported.

Environmental Performance

Advanced over-fire air and reburning, when coupled to LNBs, are able to reduce NO_x emissions to the range of 0.3 lb/MBtu.

Commercial Impact

The advanced over-fire air and reburning technologies have been or are being demonstrated as part of the Clean Coal Technology Program and are expected to achieve market niches, pending the particular economics of a given unit.

Development Needs

Operating experience is the primary need associated with over-fire air and reburning technologies. Concerns persist about the potential for furnace corrosion due to the opportunity for the formation of reducing zones in the furnace with these technologies. A continuing series of long-term field measurements using a variety of fuels under staged combustion conditions would be useful in addressing these concerns.

Atmospheric Fluidized Bed Combustion (AFBC)

Technology Description

A fluidized bed consists of a mass of granular particles with an air stream flowing upward through the particles to maintain the particles in a highly turbulent suspended state. The

bed in this state is said to be fluidized and, in general, behaves like a fluid.

This fluidized motion permits excellent surface contact between the air and the particles. If a combustible material such as coal is introduced into the bed, this mixing will permit almost isothermal conditions and efficient combustion. The operating temperature of the bed is determined by the amount of carbon in the bed, the excess air, and the rate of heat removal from the bed.

Sulfur in the coal reacts with oxygen during combustion to form SO_2 . In a fluidized bed, sulfur is removed during combustion by adding a sorbent such as limestone to the bed. In addition to reduced SO_2 emissions, NO_x emissions from a fluidized bed are lower than those from a conventional pulverized coal boiler. The lower combustion temperature in a fluidized bed minimizes thermal NO_x generation.

Fluidized beds can be distinguished by their operating pressure and their fluidizing velocity. Combustion in fluidized beds operating near atmospheric pressure is called atmospheric fluidized bed combustion (AFBC). Combustion in fluidized beds operating at higher pressures is called pressurized fluidized bed combustion (PFBC), as discussed subsequently. Each of the types of fluidized beds can be classified further by fluidizing velocity. A bed which operates at fluidizing velocities in the range of 3 ft/sec to 7 ft/sec is classified as a bubbling fluidized bed (BFB). A bed which operates at velocities in excess of about 7 ft/sec is classified as a circulating fluidized bed (CFB). There are two distinctive types of AFBC designs, as differentiated by fluidizing velocity: bubbling beds and circulating beds.

Bubbling Beds

The bubbling fluidized bed (BFB) boiler is one of the oldest of the fluidized-bed technologies. In a BFB, the fluidizing velocity is less than 7 ft/sec, which is low enough to maintain a distinct bed level. Intimate mixing of the fuel and air provides excellent combustion, while sorbent can be added to the bed for sulfur removal.

BFBs typically operate in the temperature range of 1600°F , resulting in relatively low uncontrolled NO_x formation. The coarser portion of the fuel burns in the bed, while the volatiles from the fuel and fine particles burn in the freeboard above the bed. Heat transfer surface may be installed in the bed for steam generation; however, the trend is to avoid in-bed tubes, which are subject to erosion in BFB boilers. Depending on the design, there may be recycle of bed material or use of secondary over-fire air in the freeboard section. From the fluidized bed, the combustion gases flow through a convection pass, economizer, air heater, and electrostatic precipitator or bag filter, and then to the stack. The bed material is removed through bed drains or as fly ash removed downstream from the boiler.

Steam generated in furnace and convection-pass tubes in the BFB is utilized for processes or a steam cycle as required by the system for which the boiler was installed.

Circulating Beds

In a circulating fluidized bed (CFB) boiler, fuel and sorbent are fed into a vertical combustor, which operates at relatively high velocities in excess of 7 ft/sec while recycling the material in the combustor. The fuel is burned at temperatures of 1550°F to 1650°F. Sorbent such as crushed limestone can be added to the bed for sulfur removal.

The ash and spent sorbent are removed from the process through the bed drains or collected in the particulate removal system. Impact separators and/or cyclones are used to remove the particulates from the exhaust gas between the combustion chamber and the convection pass for recycling. Typically, the combustion air is staged: it is fed at discrete levels along the combustion chamber. The suspended solids form a pressure gradient along the height of the combustor which gradually decreases with elevation.

Heat transfer sections are installed in the convection pass. In addition, heat transfer surface may be installed in the combustion chamber water walls, internals, or cyclone liners, depending on the manufacturer. After the convection pass, the gases are cooled further in an air preheater, after which they are directed to an electrostatic precipitator or bag filter, and then to the stack.

A significant advantage of CFB systems is fuel flexibility. CFBs have demonstrated the ability to burn virtually all types of coal, as well as wood, biomass, mine tailings, and refuse-derived fuels.

Development Status

AFBC is considered to be a commercial technology. AFBC units have been available commercially for about ten years, and there are over 185 AFBC units installed in North America, representing over 6 GW capacity. There are 550 units installed worldwide. Both BFBs and CFBs are offered with a traditional range of guarantees. The world's largest BFB is a 350 MW unit under construction in Japan, and CFB vendors are offering CFBs with commercial guarantees in sizes up to 400 MW.

Environmental Performance

A BFB can control SO₂ emissions during combustion with the addition of limestone. Typical SO₂ removal limits are 90 percent for medium to low sulfur coals, but somewhat higher levels can be achieved with more limestone input.

Relatively low NO_x emissions are achieved through low combustion temperatures and staged combustion. BFBs typically produce NO_x in the range of 0.2 lb/MBtu to 0.4 lb/MBtu for coal. With the addition of postcombustion reduction techniques (see discussions of selective catalytic reduction [SCR] and selective non-catalytic reduction [SNCR] in Chapter III, Part C), even lower NO_x emissions can be achieved.

SO₂ removal in CFBs is higher than for BFBs. Ninety-eight percent sulfur retention has been achieved in CFBs with moderate to low sulfur coal. CFBs typically produce NO_x less than 0.1 lb/MBtu. Hazardous air pollutant emissions need to be quantified. Non-catalytic ammonia injection techniques could enable NO_x reduction to about 0.05 lb/MBtu.

Commercial Impact

AFBC technology, especially with CFBs, is expected to continue to have a dominant role in serving the small to intermediate market for low rank fuels. It is a proven technology.

Development Needs

BFB technology is advancing primarily in applications for waste fuels such as sludge, refuse-derived fuel, tires, urban waste, and others, mainly in the industrial arena. The primary development issue associated with both BFB and CFB technology is the scale-up to larger sizes. The economics of the scaled-up designs remains uncertain. Other future advancements in CFB technology include all-internal recycle designs and continued improvements in materials of construction, especially in the area of refractory materials. Improved sulfur capture and sorbent utilization and development of acceptable uses for the byproducts are also important development needs for AFBC technology.

R&D is expected to continue in AFBC technology in areas of emissions control, internal circulation approaches, staged combustion, tube bundle design, and co-firing of biomass and other fuels.

Pressurized Fluidized Bed Combustion (PFBC)

Technology Description

A PFBC system operates a fluidized bed at a relatively high pressure of 100 psi or higher. Because of the higher pressure, the exhaust gases from a PFBC have sufficient energy to drive a gas turbine while the steam generated in the in-bed boiler tubes drives a steam turbine. This combined cycle configuration allows net cycle efficiencies in excess of 40 percent. In PFBC, the higher operating pressure allows for the use of deep beds (in bubbling beds) or denser beds (in circulating beds), which results in higher combustion efficiency and higher sulfur removal with lower sorbent requirements.

Bubbling Beds

In a pressurized fluidized bubbling bed (PFBB), coal and sorbent are fed into the fluidized bed, where combustion occurs at about 1600°F. The bed depth is typically less than fifteen feet, and the fluidizing velocity is in the range of 3 ft/sec.

Boiler tubes immersed in the bed transfer heat to feedwater, which is used to serve a steam cycle. The gases from the bed flow through a particulate removal system and then to a gas turbine, which drives a generator and the compressors to provide the fluidizing and combustion air. The particulate removal system could be cyclones, which typically remove on the order of 98 percent of the ash, or advanced hot gas clean-up filters, which remove virtually all of the ash.

The gases exhaust from the gas turbine and supply an economizer, and then exhaust to the stack. If cyclones are used for particulate removal upstream of the gas turbine, an electrostatic precipitator or bag filter is required downstream of the economizer to remove the remainder of the fly ash.

Circulating Beds

In a pressurized circulating fluidized bed (PCFB) system, coal and sorbent are fed into a fast reactor which operates at a gas velocity in the range of 15 ft/sec to 20 ft/sec. Combustion takes place at a temperature of approximately 1600°F to 1700°F. Air is supplied to a combustor near the bottom of the bed as primary air and near the top of the combustor as secondary air.

Heat generated during combustion is transferred to the steam cycle through water wall tubes, radiant tube sections, and external heat exchangers, depending on the manufacturer. Cyclones return the bulk of the solids back to the bed. The gas which exits the cyclones flows through high temperature high pressure filters to remove the remainder of the ash, and then to the gas turbine. From the gas turbine, the gases flow through an economizer and to the stack.

PFBC technology can be viewed as "first generation," as described above, and "second generation," which utilizes a topping cycle to increase the inlet temperature to the gas turbine. The fundamental feature common to both of these cycles is the application of both a gas turbine and a steam turbine in a combined cycle configuration. In the second generation cycle, a topping combustor is provided between the combustor and gas turbine. The topping combustor could utilize either natural gas or syngas (see Chapter V, Part B) to fuel the topping combustor. A high temperature high pressure particulate removal filter is installed between the combustor and topping combustor to remove virtually all of the ash upstream of the topping combustor.

The second generation PFBC plant operates with a gas turbine inlet temperature much higher than the 1600°F bed temperature attainable with first generation PFBC.

In a second generation PFBC plant using syngas, coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After passing through a cyclone and hot gas clean-up filter to remove gas-entrained particulates, the fuel gas is burned in a topping combustor to produce the energy required to drive a gas turbine.

The gas turbine drives a generator and a compressor that feeds air to the carbonizer and a PFBC. The carbonizer char is burned in the combustor with high excess air, and the vitiated air from the PFBC supports combustion of the fuel gas in the topping combustor. Steam generated in a heat-recovery steam generator downstream of the gas turbine and in the PFBC drives the steam turbine generator that furnishes the balance of electric power delivered by the plant.

Low-Btu gas is produced in the carbonizer by pyrolysis (mild devolatilization) of coal in a fluidized bed reactor. Because this unit operates at temperatures much lower than those in gasifiers currently under development, it produces a char residue. Left untreated, the fuel gas contains ammonia, hydrogen sulfide, and sulfur-containing tar and light oil vapors; and lime-based sorbents are injected into the carbonizer to catalytically enhance tar cracking and to capture sulfur as calcium sulfide.

For higher percentages of sulfur capture, zinc titanate may be required in the carbonizer. Sulfur is captured in-situ, and the raw fuel gas is fired hot. Thus, fuel gas heat exchangers and chemical or sulfur-capturing bed clean-up systems being developed for coal gasification combined-cycle plants are eliminated.

Development Status

The first application in the U.S. of PFBC bubbling-bed technology at a utility scale was at the 70 MWe Tidd PFBC Demonstration Plant owned by Ohio Power Company, a subsidiary of American Electric Power. In addition, there are four other operating PFBC plants in Europe and Asia.

There are over 50,000 hours of coal-fired operation with the four operating PFBC Plants. Most of those plants experienced relatively poor availability during their early operation; however, they currently are operating at or close to commercially acceptable availabilities. One vendor currently is offering "first generation PFBC plants" with commercial guarantees.

Several additional PFBC plants are under construction or being planned, the largest of which is 350 MWe. The operating experience of the existing PFBC plants has provided

the data base to allow subsequent PFBC plants to obtain commercial-type guarantees. However, it is not believed that a sufficient number of plants have been built to consider the technology commercially and economically mature.

To date, experience with PCFB plants is limited to pilot plants. However, based on the success of bubbling bed PFBC plants, as well as the success of atmospheric CFB plants, it is expected that PCFB plants also will become commercial successes. The key development issue associated with PCFB plants is the reliability of hot gas clean-up (HGCU) technology.

HGCU filters are being developed at high pressures and temperatures of 1000°F to 1200°F in IGCC plants; however, operating experience at the higher temperatures of 1500°F to 1700°F, which is needed for PFBC operation, is very limited. The only operating HGCU systems in the United States are the 10 MW (equivalent) slipstream at the Tidd PFBC Demonstration Plant and the 1.2 MW (thermal) Foster Wheeler pilot plant in Livingston, New Jersey. Further HGCU testing is scheduled for the Wilsonville Power System Development Facility in Alabama under the sponsorship of DOE.

Through the DOE Clean Coal Technology Program, two demonstrations of PCFBs currently are planned. The first project involves a first generation PCFB, and the second project involves a second generation system using a PCFB. The technology comes from a strong foundation of pilot plant testing. The primary development issue is in the area of hot gas clean-up. This technology is not yet deemed to be commercially available. However, it should be noted that both of the Clean Coal Technology Demonstration projects are being viewed by the owners as commercial-type generating units.

Environmental Performance

PFBC plants can achieve sulfur retention on the order of 95 percent or better, NO_x emissions on the order of 0.15 lb/MBtu without any additional treatment, and NO_x emissions as low as 0.05 lb/MBtu with additional treatment such as ammonia injection. The higher cycle efficiency of PFBC plants, 40 percent or better, results in a corresponding decrease in all emissions, including CO₂.

The second generation PFBC technology is projected to achieve 45 percent overall plant efficiency, resulting in even lower emissions. As with the first generation PFBC systems, 95 percent sulfur capture can be attained, and NO_x emissions are expected to be 0.3 lb/MBtu or less. Use of a hot gas clean-up filter will result in particulate emissions in the range of 3 parts per million (ppm). For NO_x control to lower levels, selective catalytic reduction (see Chapter III, Part C) may be required. The SCR equipment could be located in the heat recovery unit.

Commercial Impact

PFBC technology is one of the leading coal-based power generating technologies of the future. Most studies indicate that PFBC technology will have efficiency, capital cost, and operating cost advantages over most other coal-based electric generating technologies. Therefore, once PFBC technology becomes commercially mature, it is expected to play a significant role in the marketplace.

Second generation PFBC technology has the ability to take advantage of several developments in combustion turbine technology (see Chapter IV, Part A) with regard to firing temperatures, which currently are limited to its present 2350°F. Those developments could raise the thermal efficiency of a second generation PFBC plant to nearly 50 percent.

Assuming that the corresponding capital cost remains competitive, as it is expected to do, the high-efficiency second generation PFBC plants should provide the market with a very attractive option for burning coal.

Development Needs

The primary development need for PFBC technology is operating experience. The large-scale demonstrations of bubbling beds and planned demonstrations of circulating beds are expected to verify the merits of PFBC technology and identify additional R&D needs. This operating experience should mitigate risks associated with optimization and scale-up issues, both from a process and from a system perspective.

As with any new generating technology, the progression from the laboratory scale to pilot plant testing to full-scale demonstration is essential to commercial acceptance. PFBC technology repeatedly has passed the scrutiny of economic evaluations, risk assessments, and design reviews with the conclusions that the technology has significant merit. However, with the capital-intensive nature of the electric utility industry, the risk of using this technology prior to its being proven must be mitigated through appropriate incentives.

Therefore, the support for demonstration of PFBC technology through the CCT Program should be continued for additional near-term projects, either domestic or international. This government cost sharing or other appropriate incentives will enhance the acceptance of PFBC technology into the marketplace.

Another important development need for PFBC plants is in the area of sorbent utilization. Reduced sorbent requirements can have noticeable impacts on the economics of the technology for both bubbling and circulating PFBC designs. The utilization, rather than the disposal, of PFBC ashes is also of significance. Unlike AFBC ashes, which tend to

contain significant amounts of free lime, PFBC ashes typically have less than 1 percent free lime, making the ash more stable and usable for secondary applications.

The key to both the PCFB plants and the second generation PFBC plants is hot gas clean-up technology. Hot gas clean-up filter operating experience at the temperatures required for use in these technologies is limited to pilot plant testing, testing at the 10 MW (equivalent) Tidd slipstream, and testing at the Wakamatsu PFBC Demonstration Plant in Japan. Continued DOE support for testing of hot gas clean-up technology is required to achieve the confidence in this technology required for commercial applications.

Other development needs include optimization of the solids handling systems, especially the integration of the carbonizer; accelerating development of the topping combustor; and development of materials and components, especially valves, required for higher-temperature second generation PFBC systems. R&D support for these elements, which are geared toward improving the cost, performance, and efficiency of PFBC plants, warrants funding consideration.

Other Combustion Technologies

In addition to the technologies given attention in this chapter, there are other technologies which also merit discussion.

Slagging Combustors

Technology Description

Slagging Combustors have been developed for simultaneous NO_x and SO₂ control in coal-fired boilers. In a slagging combustor, pulverized coal and limestone powder or some other sorbent are injected into an annular region of a cyclonic combustor to burn the coal at a temperature of about 3000°F. The coal is burned at sub-stoichiometric conditions to control NO_x formation. The sorbent injected into the combustor removes SO₂. The ash contained in the burning coal forms molten slag, which flows from the burner to slag taps for removal from the furnace. There currently are two types of slagging combustors: an air-cooled design offered by Coal Tech and a water-cooled design offered by TRW.

Development Status

Slagging combustors have received funding from the DOE Clean Coal Technology Program for demonstration. The Coal Tech combustor was demonstrated in Williamsport, Pennsylvania, and the TRW combustor will be demonstrated as part of the 50 MW Healy Clean Coal Project in Alaska.

Environmental Performance

Testing of slagging combustors has yielded NO_x emissions of 0.3 lb/MBtu and in excess of 70 percent SO₂ retention.

Commercial Impact

Slagging combustors are targeted for both retrofit applications and new applications for combustion of low-grade fuels (including solid waste fuels), limited sulfur control in coal-fired boilers, and conversion of ash to slag.

Development Needs

Slagging combustors have been demonstrated at 20 MBtu/hr to 40 MBtu/hr; however, ongoing durability testing is required to determine their commercial readiness. Scale-up and testing at larger sizes is required before slagging combustors can be deemed ready for offering at electric utility scale with necessary guarantees. Completion of the ongoing Healy project is crucial in providing necessary performance and economic data.

Co-Firing

There is the possibility of reduced emissions and lower fuel costs from utilization of co-firing or co-combustion techniques in combustion technologies. Some examples of co-firing include:

- Firing coal with refuse-derived fuels (RDF) to reduce the volume of urban waste and provide low-cost fuels.
- Co-firing of coal with natural gas to reduce NO_x, SO₂, and CO₂ emissions from coal-fired boilers.
- Firing biomass with coal to reduce fuel costs while reducing SO₂ and CO₂ emissions.

Developments in Clean Coal Technologies such as fluidized bed combustion and gasification have the potential to allow further opportunities for co-firing coal with biomass and RDF.

Among the various alternative fuels with the potential for co-firing with coal, the greatest experience has been gained with RDF. Limited experience has been gained co-firing coal with natural gas, some forms of biomass (for example, wood waste), and nonhazardous waste (for example, automobile tires).

Many other alternatives offer possibilities, but uncertainties regarding price and availability have prevented significant and sustained co-firing ventures. Each new fuel combination also presents new questions about combustion chemistry and byproducts. The prospect of reduced fuel costs to be achieved through co-combustion creates the incentive for further exploration and development.

It has been noted that special co-firing fuel combinations can be found to achieve heat transfer objectives required in existing systems. For example, co-firing a coal-No. 2 oil slurry with natural gas can achieve the required radiation heat transfer in a facility designed to burn oil alone. Co-firing with natural gas also offers the opportunity to burn low-quality (marginal) coal in applications where such coal ordinarily could not be used. This practice would enable use of an energy resource which otherwise would be wasted.

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C. Postcombustion

A variety of constituents found in the products of coal combustion have been targeted for postcombustion control by national and local regulatory agencies. Primary among these are sulfur dioxide (SO₂), oxides of nitrogen (NO_x appearing mainly as NO), and particulate matter. Additional emphasis recently has been placed upon the control of hazardous air pollutants (HAPs or "air toxics"), which are usually found in trace quantities, and carbon dioxide (CO₂) as a "greenhouse gas." Concern also has been expressed about the use and/or disposal of gas, liquid, and solid byproducts of the control process.

This section specifically addresses technologies for the postcombustion control of these emissions. The control of NO_x by combustion system improvements and the control of SO₂ and NO_x through the implementation of fluidized bed combustion technology are covered in Chapter III, Part B. In most cases, the postcombustion control technologies discussed here may be added to these two technologies to reduce emissions further.

The type of control technology employed for a specific application depends upon the regulatory requirements as well as upon the postcombustion emission levels. Emissions are highly site specific, depending upon the fuel being burned and the combustion system. For example, emissions (tons/hr) from a nominal 500 MWe modern pulverized coal-fired boiler at 100 percent load burning 2-1/2 percent sulfur, 16 percent ash, 12,360 Btu/lb Eastern bituminous coal are calculated as follows: SO₂ -- 9.3 t/h; NO_x as NO₂ -- 0.7 t/h; fly ash -- 22.9 t/h; and CO₂ -- 485 t/h. The use of low-NO_x burners has been assumed. Recent studies have indicated the total emissions rate of key trace metals on a 500 MWe unit might be on the order of 0.02 lb/hr to 1.7 lb/hr and trace organics might be comparable, depending upon the coal chemistry and power system configuration. However, these levels remain highly preliminary pending the completion of tests currently underway.

A variety of postcombustion technologies provide significant control of these emissions today. Technologies typically include filtration, condensation, absorption, adsorption, and various chemical reactions. Specific technologies are available today to control SO₂ and NO_x emissions at 90 percent to 95 percent and particulate emissions by 99.5 percent or more. Therefore, the key issues for established, new, or advanced technology include (1) meeting the emissions requirements at an acceptable minimum cost (capital, operations, and maintenance) and (2) achieving reliable long-term operation. The strategies for postcombustion control of all emissions from coal-fired systems are formulated by considering the specific coal, type and extent of emissions reduction requirements, boiler

design, required availability, location, new versus old site, equipment age, and remaining life. In some cases, fuel selection alone will provide the desired emissions rates. In other cases, the ultimate strategy may include a combination of technologies which work in series or parallel to meet the emissions limits and power supply requirements cost-effectively and reliably.

Desulfurization

A broad range of sulfur dioxide (SO₂) control technologies have been employed since their introduction to the coal-fired power industry in the early 1970s. Many of the options have been developed and demonstrated at least at the pilot plant scale. However, relatively few have been commercialized over this time period, and even fewer are under serious consideration for major commercial flue gas desulfurization (FGD) applications in the near future. The technology most widely applied today is non-regenerable wet scrubbing, with better than 83 percent of the installed base and over 90 percent of the identified new capacity. The second largest category is dry scrubbing or spray dry scrubbing, with about 10 percent of the installed base. Remaining units include regenerable wet scrubbing systems, sorbent injection FGD systems, and a few other types.

Non-Regenerable Wet Scrubbing

Technology Description

Within this class, the countercurrent spray tower is the dominant form used today. The contacting zone consists of an open, usually cylindrical, chamber containing banks of spray nozzles oriented downward. The flue gases pass vertically upward through the banks of sprays in countercurrent flow. The details of nozzle placement differ from design to design. In one design, a perforated tray is used to promote uniform flue gas flow distribution and enhance gas/slurry contact. More than 15 manufacturers have supplied utility boiler scale spray towers.

Alternatives to the countercurrent spray tower have been used in the past on about 15 percent of existing installed wet scrubber capacity. The principal deviations were the use of venturi scrubbers for simultaneous SO₂ and particulate capture; two-loop scrubbing; and, finally, the horizontal flow scrubbers.

Limestone and lime are the most common reagents used in wet scrubbers, with about 71 percent using limestone and nearly 16 percent using lime. All of the wet scrubber capacity purchased since 1989 has used limestone or lime. Even when lime and limestone are not used directly in the scrubber, they are used frequently to regenerate the sorbent. In the so-called "Dual Alkali Process," lime or limestone is used in combination with sodium carbonate. These systems constituted about 2.2 percent of wet scrubber capacity as of

1989. The other reagents used in non-regenerable wet scrubber processes include alkaline fly ash, waste sodium carbonate, and sea water.

SO₂ performance enhancing additives have seen limited use to date. The most popular additives are organic buffers and magnesium oxide (MgO). In most cases, the MgO is not a separate additive, but rather a naturally occurring impurity in the original limestone from which the "magnesia enhanced lime" is produced.

The two most popular organic buffers are sodium formate and a waste stream from the manufacture of adipic acid, called DBA. These additives have proven to be effective performance enhancers under certain conditions. To date few FGD systems have been designed in such a way that the organic buffers are required to meet the SO₂ performance guarantees. Rather, these additives are more likely to be used when utilities can justify "over-scrubbing" of SO₂ in order to obtain SO₂ allowances for sale in the SO₂ allowance market.

The maintenance and operating problems involving scaling and spent reagent dewatering were discovered in early lime and limestone scrubbing systems. These have been overcome by the use of either "inhibited oxidation" or "forced oxidation" chemistry in modern scrubbing systems.

- *Inhibited oxidation:* Colloidal sulfur is added to a limestone scrubber and partially oxidized to thiosulfate. This minimizes the partial oxidation of CaSO₃ to form gypsum and minimizes the associated scaling.
- *Forced oxidation:* Air is added directly into the reaction tank portion of the scrubber vessel (in-situ) in order to promote the complete oxidation of the CaSO₃ to CaSO₄ • 2H₂O -- the latter being gypsum. The gypsum byproduct is similar to naturally occurring gypsum and may safely be landfilled while meeting environmental requirements. In addition, the byproduct gypsum may be sold for use in the manufacture of wallboard. The commercial use of scrubber byproduct gypsum has become common in Japan and Germany and to a limited extent in the U.S. The final selection of byproduct use or disposal depends upon site specific economics (see Chapter III, Part C, Byproduct Utilization).

Several new scrubber designs currently are being compared to the spray tower. Two of these designs are the "Jet Bubble Reactor" (JBR) system and the co-current downflow packed tower design. The former bubbles the flue gas through a limestone-water slurry tank to absorb the SO₂, while the latter uses co-current flow instead of counterflow to contact the flue gas and the slurry in a packed tower. Both are being demonstrated as part of the DOE Clean Coal Technology program.

Development Status

Non-regenerable wet scrubbing has been extensively commercialized and is the technology of choice today for coal-fired utility boiler postcombustion SO₂ control. Major problems which reduced availability in the early countercurrent spray tower designs have been largely resolved in the current generation of countercurrent spray tower designs. These units have availabilities of 98 percent and routinely meet performance guarantees. Excess equipment redundancy is being reduced, based upon actual operating experience.

A salable byproduct (gypsum) can be produced where economically justified or can be disposed of safely in a purity exceeding the mineral gypsum mined today. A range of SO₂ removal capabilities are available, depending upon the removal requirements, with removal efficiencies in excess of 95 percent being guaranteed. Ongoing improvements (see below) focus on reducing capital and operating costs.

Environmental Performance

New non-regenerative lime and limestone based wet scrubbing systems routinely operate with SO₂ removal efficiencies from 90 percent to 95 percent, depending upon the initial design requirements. In selected cases, removal efficiencies of 97 percent have been required and met. Limestone and lime utilization rates can exceed 95 percent (calcium-to-sulfur ratio of 1.01 to 1.05).

By contrast, some dry injection processes use less than 30 percent of the available reagent. Auxiliary power requirements, due primarily to the flue gas pressure loss and the slurry circulation, are around 2 percent of the power production, depending on the fuel sulfur content, the removal efficiency, the reagent (lime, limestone, or magnesium enhanced lime), and the possible use of additives. Approximately three tons of salable byproduct gypsum (or similar quantities of landfill gypsum) are produced for each ton of SO₂ captured.

All lime or limestone based wet scrubbing processes ultimately emit some incremental carbon dioxide (CO₂) indirectly as a result of increased plant auxiliary power usage and directly from the utilization of limestone. This is typically less than 2 percent of the power plant CO₂ emissions (see Chapter III, Part C, Carbon Dioxide Controls).

Commercial Impact

As noted above, non-regenerative wet scrubbing systems are used in 90 percent of the new applications where postcombustion SO₂ control is required. Over the last 5 years, approximately 65 GWe of wet scrubbing systems have been sold worldwide. Until new technologies demonstrate economics and reliability superior to current scrubber technology,

counterflow spray tower designs will likely remain the dominant choice for postcombustion SO₂ control.

Development Needs

The primary wet scrubber improvements will focus on cost reduction (capital and operating) and efficiency. Further work is recommended to:

- Improve mist eliminator designs (reduce entrainment) to increase spray tower gas velocity and thereby reduce module diameter and cost.
- Identify design and process chemistry improvements to reduce scrubber height, increase SO₂ removal, lower pumping rates, and -- most importantly -- reduce cost.
- Evaluate system components to reduce redundancy where justified by field experience.
- Reduce auxiliary power consumption to the range of 1 percent to 1-1/2 percent of plant power output.

Once a scrubber is achieving, say, 95 percent efficiency, the economic benefit of operating at a higher efficiency to gain SO₂ allowances is greatly diminished. Today's SO₂ scrubber designs can achieve almost any desired efficiency without any breakthrough technologies. Therefore, essentially all development efforts are directed toward cost cutting measures.

Dry Scrubbing

Technology Description

The term "dry scrubbing," as used here, refers to the class of FGD processes in which an aqueous slurry or solution of alkaline reagent is sprayed into the boiler flue gas in such a manner that the water evaporates immediately within the scrubber and the reaction products are removed as an essentially dry powder. This technology is also referred to as spray drying, spray dry absorption, and semi-dry scrubbing.

The advantages of dry scrubbers over wet scrubbers include simpler, cheaper materials of construction, a dry waste product, no waste water stream, lower fresh water demand, and simpler process control. The disadvantages include less efficient use of reagent, the exclusion of limestone as a reagent option, and a somewhat lesser capability for high SO₂ efficiency. Because of their combination of strengths and weaknesses, dry scrubbers have become important in selected niche markets. Dry scrubbers compete very favorably in arid climates and when applied to low sulfur coals, especially where fly ash is highly alkaline.

Several simple ways exist to categorize dry scrubbers. These include, in part, the reagent used, the method of atomization, the type of dust collector used, and the general features of the dry scrubber itself. By far the dominant reagent used in dry scrubbing is slaked lime. Whereas most wet scrubbers that use lime also have a significant magnesium content, lime used in dry scrubbers generally has a low magnesium content (less than 1 percent MgO).

Dry scrubbers employ either dual fluid or rotary disk atomizers. The latter are used much more commonly. The rotary atomizers generally are more energy efficient but are mechanically sophisticated and require a high degree of maintenance.

Most dry scrubbers use the cylindrical downflow design fashioned after the conventional spray dryer. Horizontal flow dry scrubbers also have been built utilizing several dual fluid atomizers.

Both electrostatic precipitators and fabric filters (baghouses) have been used with dry scrubbers. Unlike wet scrubber installations, the dust collector is placed after the dry scrubber. Fabric filters generally are preferred because the solids deposited on the bag filter surfaces are in more intimate contact with the flue gases and therefore are a more effective absorber of residual SO₂ from the flue gas.

The wastes from dry scrubbers consist of mixtures of fly ash, calcium sulfite, and calcium sulfate. Although this material is dry, in contrast to the sludge from a wet scrubber, it is generally considered to be a waste.

Development Status

Dry scrubbing has been commercialized extensively for selected applications where emissions control requirements, fuel, and site specific economics justify the technology for coal-fired utility boiler postcombustion SO₂ control. Ongoing technology improvements focus on improving removal efficiency, reducing overall operating and maintenance costs, and evaluating waste use and disposal options.

Environmental Performance

Lime-based dry scrubbing systems, including the particulate removal equipment, routinely operate with SO₂ removal efficiencies from 70 percent to 90 percent on lower sulfur coals (<1.5 percent sulfur). In selected cases, removal efficiencies of 98 percent have been reported. Calcium-to-sulfur molar ratios typically range from 1.1 to 1.6, although the presence of alkali in the coal ash may reduce the reagent requirements. This compares to 1.01 to 1.05 in most wet scrubbers.

Auxiliary power requirements, due primarily to the flue gas pressure loss and the slurry atomization, range from 0.5 percent to 1.0 percent of power plant output, depending on the fuel sulfur content, the removal efficiency, and the possible use of additives. Approximately 2.2 tons of dry waste product (plus ash content) are produced for each ton of SO₂ removed. Dry scrubbers also have demonstrated the ability to remove some mercury and chlorides.

Commercial Impact

Dry scrubbing will continue to be applied to selected cases when fuel sulfur content, ash chemistry, and performance requirements make it the most economical choice. Dry scrubbers are used most frequently for coals with less than 1.5 percent sulfur where higher reagent use is less of a disadvantage. The lower capital cost also can be beneficial for retrofits with short remaining plant life and units used for peak load operation.

Development Needs

The primary dry scrubber improvement need is in the area of reagent utilization, which is typically in the range of 65 percent to 85 percent. Means to achieve this improvement include operation of the dust collector at lower temperatures, improvements in flue gas and slurry mixing to minimize cold spots, and operation of the dry scrubber at higher relative humidity. Resisting these potential improvement measures is the concern that these changes could result in additional operating and maintenance problems.

Regenerable Wet Scrubbing

Technology Description

Regenerable FGD processes involve the treatment of the scrubber waste to recover and reuse the sorbent. This regeneration step can be a chemical, thermal, or electrical process. Common to all regenerative FGD processes is the formation of a useful sulfur product. In total, the impact of regenerable processes in the marketplace has been small. The primary regenerable processes that have been commercialized include the MgO process, the Wellman-Lord process, and the Bergbau-Forschung Carbon Adsorption process. The MgO process involves thermal regeneration; the Wellman-Lord process uses absorption-stripping in an aqueous solution of sodium sulfite-bisulfite; and the Bergbau-Forschung process is a dry process using carbon adsorption.

Development Status

Regenerable wet scrubbing has been commercialized, but history has indicated that the existing processes have not been judged by their use to be economically attractive.

Environmental Performance

Regenerable wet scrubbing systems generally have achieved SO₂ control comparable to non-regenerable systems. Auxiliary power requirements are generally higher than non-regenerable systems. These scrubbing processes produce sulfur products in some useful form. The quantity depends upon the specific process chemistry. In general, CO₂ emissions do not increase directly because limestone is not consumed in the process. However, if auxiliary power requirements are higher than non-regenerable wet scrubbing by 1.2 percent of the plant power production, then the CO₂ emissions benefit over conventional systems is lost.

Commercial Impact

Until regenerable systems demonstrate economic viability, they are not expected to have a major future commercial impact. Selected cases may arise from time to time which may make one of these processes attractive.

Development Needs

There are no needs at this time.

Sorbent Injection Systems

Technology Description

In the context of this report, "Sorbent Injection Processes" include all technologies in which a sorbent is added dry or slightly damp within the confines of the existing boiler or flue work. As such, these processes require relatively little new equipment and thus are suitable candidates for retrofit applications. In general, the level of SO₂ reduction is relatively low to moderate, and the sorbent requirements are relatively large. Sorbent injection includes processes by which sorbent is added with the fuel or injected in the vicinity of the burners, the furnace arch, the convective pass, the economizer, and upstream of the particulate collector. SO₂ removal performance depends upon reagent chemistry, reagent size distribution, temperature of the flue gas, and residence time.

The sorbents used for various injection processes include limestone (CaCO₃), lime (CaO), hydrated lime (Ca[OH]₂), soda ash (Na₂CO₃), sodium bicarbonate (NaHCO₃), and naturally occurring sodium carbonates and bicarbonates such as trona and nahcolite. In 1989, 24 coal-fired boilers worldwide, with a combined capacity of 1,707 MWe, were using sorbent injection systems. Most of these units are located in Germany and Sweden. Most of the European installations use calcium-based sorbents. In North America, only three units are using sorbent injection commercially.

Development Status

Sorbent injection SO₂ control processes have seen some limited application. DOE Clean Coal Technology programs have demonstrated the technical viability of several options at commercial scale, and most are ready for commercial use.

Environmental Performance

Sorbent injection systems, including the effects of the particulate removal equipment, have been operated with SO₂ removal efficiencies from 40 percent to 70 percent on low to medium sulfur coals (<2.5 percent sulfur). Calcium-to-sulfur ratios typically range from 2 to 3, resulting in modest calcium utilizations. Auxiliary power requirements are due primarily to sorbent injection energy and are usually less than 0.5 percent of the plant power output. Several tons of dry waste product (ash, spent sorbent, and unused sorbent) are produced for each ton of SO₂ removed, depending primarily upon the process, removal percentage, and reagent reactivity.

Commercial Impact

Because of their relatively low initial capital cost and their relative ease of installation, sorbent injection systems are considered to be particularly attractive for retrofits of older power plants where only modest levels of SO₂ control are needed and the remaining plant life is short. In addition, they are used in conjunction with low sulfur coal in order to meet site specific SO₂ emission requirements. Internationally, these technologies will offer a method to reduce SO₂ emissions significantly at a modest capital cost when the alternative would be no emissions control because of capital constraints.

Development Needs

Improvements in both sorbent utilization efficiency and SO₂ removal efficiency are required to increase the attractiveness of furnace sorbent injection processes. Sorbent utilization can be as low as 15 percent, and SO₂ efficiency varies from 30 percent to 60 percent, depending upon the reagent. Sorbent injection systems also must be improved to achieve the desired reliability.

Other SO₂ Control Processes

Not all processes that produce a useful product can be categorized properly as regenerable processes. The wet limestone scrubber producing salable gypsum is the obvious example. Ammonia scrubbing to produce ammonium sulfate for fertilizers is an example where the reagent, ammonia, is reformulated from a gaseous fertilizer to a solid one with a moderate value-added component. Another example is the SNOX process, in which no reagent is

used for SO₂ capture. This process merely oxidizes the SO₂ to SO₃ and subsequently condenses the SO₃ as sulfuric acid for sale.

Denitrification

Emissions of nitrogen oxides (NO_x) from coal-fired boilers may be limited through the application of combustion process changes and postcombustion technology. For new systems, the most cost-effective approach is to install low-NO_x burners to minimize the initial formation while adding postcombustion technology if further reductions are needed. This is also generally true for retrofit applications, although site specific evaluations are needed. An overview of low-NO_x burners and combustion technology was presented earlier. This section is devoted specifically to postcombustion systems.

Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) deNO_x technologies are the major systems applied commercially today for postcombustion control of NO_x from coal-fired boilers. In both of these technologies, NO_x is reduced to nitrogen (N₂) and water (H₂O) through a series of reactions with a reagent injected into the flue gas. Several alternative postcombustion NO_x reduction processes are in various stages of development, but these other processes have not yet received widespread commercial application. In addition, three combined processes have been demonstrated for simultaneously controlling NO_x and SO₂ emissions in coal-fired utility applications.

Selective Catalytic Reduction (SCR)

Technology Description

In an SCR system, ammonia is injected into the flue gas stream and reacts with NO_x species as the gas passes over a catalyst within an appropriate temperature window. The ammonia may be stored either as anhydrous ammonia or as an aqueous solution with a 25 percent to 28 percent concentration. Urea solutions have been tested as an alternate reagent, and NO_x emission reductions comparable to those obtained with ammonia have been observed. The optimal operating temperature is dependent on the specific catalyst and is usually in the range of 450°F to 840°F.

The catalyst used may be of several types. Most of the operating experience to date has been with base metal catalysts using titanium dioxide with small amounts of vanadium, molybdenum, tungsten, and other active chemical agents. Various technical criteria (especially flue gas composition) determine the type of catalyst to be used in a specific application.

The catalyst may be placed on a metal plate substrate or extruded as honeycomb monolith sections which then are assembled into blocks. These block sections then are stacked in

a holder to make up the SCR reactor module. The plate type arrangement offers lower pressure drop and is less susceptible to pluggage and erosion in high dust applications. The honeycomb arrangement provides for higher catalyst surface area in a similar reactor volume.

The design of each SCR system is unique, based on space constraints, temperature requirements, and boiler fuel. The ammonia is mixed with air or steam at about a 20:1 ratio for injection into the flue gas upstream of the catalyst reactor. The ammonia flow rate is controlled to maintain the mole ratio of ammonia to inlet NO_x within the design range -- typically 1:1. The required removal efficiency and allowable ammonia slip determine the ammonia to NO_x mole ratio.

The reactor may be installed in a vertical or horizontal flow orientation, depending on the fuel used, space availability, and arrangement of adjacent equipment. For coal-fired applications, vertical downward flow is usually employed to enhance ash removal and cleaning. Uniform gas flow distribution and complete mixing of the reagent with the gas stream are required for maximum efficiency and low ammonia slip through the system.

SCR units are located predominantly at two points downstream of a coal-fired boiler: "hot side, high dust" units between the economizer and the air heater and "tail-end" or "cold side" units downstream of both the particulate collection and desulfurization systems. Tail-end installations can be more compact and avoid catalyst erosion and pluggage problems. However, the flue gas must be reheated to the optimum reaction temperature. As experience has been gained with high dust loadings and improved catalyst formulations, most new installations have used the "hot side, high dust" configuration to minimize costs. Several applications also have been evaluated where catalyst may be installed directly within existing fluework and as regenerative air heater replacement material.

Development Status

SCR deNO_x systems for pulverized coal-fired boilers generally can be considered as mature technologies in Germany and Japan because of their extensive installations. As of 1990, there were 40 SCR systems on a total of approximately 11,000 MWe of low-sulfur (< 1 percent) coal-fired generating capacity in Japan. SCR systems are installed on approximately 150 German boilers with a capacity of approximately 33,000 MWe. Most of the German installations are "high dust" configurations with low sulfur coal (0.7 percent-1.2 percent). Most of these systems use anhydrous ammonia as the reducing agent and achieve 80+ percent NO_x emission reduction. Approximately 150 to 200 of the 500 SCR systems installed worldwide are operating on coal-fired plants.

Over the last few years, several SCR systems have been sold for U.S. coal-fired generating capacity. These applications range from 224 MWe to 450 MWe in size and will fire

Eastern coals with up to 2.5 percent sulfur. These units are designed to provide a 45 percent to 80 percent reduction in NO_x to augment low- NO_x combustion systems in order to achieve the desired NO_x emissions. Most of the experience to date has been on lower sulfur coals in Japan and Germany (<0.5 percent and <1.2 percent sulfur, respectively). U.S. coals typically have higher sulfur content and different ash constituents, and there is still concern about catalyst life and performance attributable to these differences.

Environmental Performance

SCR de NO_x systems typically are designed to reduce NO_x emissions by 45 percent to 90 percent, depending upon the regulatory requirements and inlet NO_x concentrations. Since reagent and catalyst requirements increase as the NO_x reduction requirements increase, units are designed to minimize costs while providing the necessary NO_x emission reductions. Most units are designed to remove less than 80 percent of the inlet NO_x because of escalating catalyst costs at higher efficiencies. In most recent U.S. coal-fired boiler applications, the combination of advanced low- NO_x combustion systems and SCR de NO_x systems will reduce NO_x emissions to less than 0.1 lb/MBtu as NO_2 .

Not all of the reagent takes part in the reactions connected with NO_x reduction. This unreacted reagent is found as ammonia species in the exit flue gas stream. This ammonia slip routinely is limited to less than 5 ppm to 10 ppm by volume based upon fuel type.

Commercial Impact

SCR de NO_x is a high efficiency technology but may represent a higher cost alternative for controlling NO_x emissions as compared to most low- NO_x combustion systems and modifications. In many cases, it is more economical to reduce initial NO_x formation through the combustion system first and then, if required, use SCR de NO_x systems. Plant specific conditions must be evaluated to determine the most economical NO_x control strategy and system. SCR de NO_x systems have demonstrated the ability to remove high levels of NO_x from coal-fired plants outside of the U.S. and will gain wider acceptance for U.S. coal-fired plants as additional experience is gained with U.S. fuels. If recent sales history is an indication, most new coal-fired boilers in the U.S. will be sold with SCR de NO_x systems or the capability to install them effectively later if regulatory requirements change and sufficient experience is gained with U.S. coals.

Development Needs

Although there are two industrial size systems burning low sulfur coal in operation in the U.S. today, several pilot programs burning high sulfur coal currently are installed at four coal-fired boilers and are addressing the specific areas for improving the technology:

- Catalyst life for medium to high sulfur coals.
- Erosion and pluggage concerns for high dust applications.
- Poisoning of catalyst by trace elements, chlorides, and SO₃.
- Excessive oxidation of SO₂ to SO₃ by the SCR catalyst.
- Air heater fouling with ammonium bisulfate.

Continuing research will focus on development of advanced catalyst systems with extended life and minimum SO₂ to SO₃ conversion. Continued successful performance of large-scale SCR systems on oil and gas-fired boilers is expected to increase utility boiler operator confidence, define actual useful catalyst life, and contribute to continuing system cost reductions through increased vendor competition, improved engineering, and better catalysts.

Selective Non-Catalytic Reduction (SNCR)

Technology Description

SNCR involves the injection of a reducing reagent into the furnace at relatively high temperatures to react with NO_x. The desired reaction occurs in a temperature window of 1600°F to 2000°F. Above this window, the reagent may be oxidized, resulting in the formation of additional NO_x; below the window, the rate of reaction is slowed, which may result in excessive emissions of unreacted reagent.

The optimum reaction temperature window is also influenced by the O₂, CO and SO₂ concentrations in the flue gas. High CO concentrations which may result from the installation of low-NO_x burners reduce the removal efficiency. High SO₂ concentrations increase the temperature for optimal performance. Sufficient mixing of the reagent with the flue gas and adequate residence time for reaction in the furnace are critical for reducing NO_x emissions. In general, NO_x reductions are lower and chemical consumption is higher than with SCR. Typical reagent-to-inlet-NO_x stoichiometric ratios are 2:1. Since SNCR does not require the use of a catalyst, capital costs are lower than with SCR.

Ammonia (NH₃) or urea ([NH₂]₂CO) may be used as the reducing reagent in an SNCR application. The urea may be stored as a solid or mixed with water and stored as a solution. The urea-NO_x reaction occurs in a relatively narrow temperature range (about 1650°F to 1800°F). Unlike ammonia, the storage and use of urea is not subject to Superfund Amendments and Reorganization Act (SARA) Title III reporting requirements. However, the use of urea may result in emissions of N₂O, a greenhouse gas. Some work

also has been done using isocyanate and cyanuric acid as the reducing agents, but these are not yet widely commercialized. Additives such as hydrogen, hydrogen peroxide, and ethane may be used to lower the effective temperature for the NO_x reduction reaction. SNCR may be improved through joint use with reburning technology.

A typical SNCR system consists of storage and handling equipment for the reagent, equipment for mixing the chemical with the carrier (compressed air, steam, or water), and the injection equipment. The ammonia or urea injection ports typically are positioned at several locations in the furnace. For most utility boiler applications, the correct temperature window is typically in the convection pass. Multiple injection locations usually are needed to maintain NO_x reduction efficiency as the flue gas temperature profile in the boiler changes with load.

Development Status

Ammonia based SNCR was developed and patented by Exxon and is marketed under the trade name Thermal De NO_x^R . The Thermal De NO_x^R process was installed on a new 500 MWe boiler firing 1.5 percent sulfur coal. NO_x emission reductions above 50 percent were achieved over a range of boiler loads, but ammonia slip could not be maintained below 10 ppm at full load.

The process also has been applied to 10 stoker boilers in the 50 MWe to 150 MWe range firing coal or wood. Recently, the process has been installed on a 110 MWe coal-fired boiler in the U.S. and is reported to be reducing NO_x emissions by 50 percent. A third coal-fired application in the U.S. has achieved 76 percent NO_x reduction on a circulating fluidized bed boiler.

The $\text{NO}_x\text{OUT}^{\text{TM}}$ process is a urea based SNCR system. The process has been applied to a variety of coal-fired boilers, including stoker, circulating fluidized bed, and tangentially fired units, with NO_x reductions of 40 percent to 60 percent. EPRI owns the basic patents for the urea based SNCR system and has licensed the technology to Nalco Fuel Tech. The NO_xOUT process incorporates specific chemical and mechanical features which broaden the effective temperature range.

SNCR has been tested on a number of commercial plants and applied commercially to at least 8 European coal-fired boilers ranging in size from 80 MWe to 500 MWe, beginning in 1986. By 1989, SNCR processes had been installed on 1,700 MWe of coal-fired generating capacity. Both ammonia and urea based systems are in operation.

Environmental Performance

Current demonstrations on 5 U.S. utility boilers representing a range of boiler types and

firing oil and coal have NO_x emission reductions ranging from 20 percent to 60 percent. Short-term demonstrations on coal-fired boilers have shown 40 percent to 55 percent NO_x reduction with ammonia slip less than 5 ppm.

SNCR performance is very dependent on temperature and sufficient residence time at the appropriate reaction temperature. In large utility boilers, the desired temperature window may occur in the convection pass cavities, which may limit NO_x control to 20 percent to 40 percent. Injection in the convection pass limits NO_x reduction because of difficulty in dispersing the reagent and the limited residence time in the desired temperature range. "Though some manufacturers report NO_x reduction levels over 80 percent, the common view is that SNCR processes generally are capable of 30 percent to 50 percent reduction, on average, covering different operating conditions [excerpt from an IEA Research report]." High ammonia slip has been reported in some instances.

Commercial Impact

SNCR deNO_x system performance is relatively sensitive to reagent injection location (especially with load change) and to rapid complete mixing of the reagent and flue gas. Coal-fired utility boiler SNCR deNO_x systems are capable of moderate NO_x reduction while having relatively high reagent usage. As a result, SNCR technology will likely continue to be used for specific applications where the initial NO_x levels, NO_x reduction requirements, and boiler/furnace geometry are conducive to SNCR systems.

Development Needs

Current developments to improve the SNCR process for coal applications include evaluation of alternative reagents, including urea, cyanuric acid, and ammonium sulfate. Expanding the temperature range (including the impact of cycling) for maximum NO_x reduction is a primary need for greater commercial application in coal-fired plants. One SNCR vendor claims to have developed a small ammonia injection nozzle which reduces the installed cost of the injection ports and minimizes the disturbance of existing boiler tubes. The nozzles may be retracted from the gas stream when not in service. On-line monitoring of ammonia emissions also may be incorporated into the reagent injection control logic. Questions remaining for broad commercial acceptance for coal-fired boilers include:

- Limiting emissions of unreacted ammonia (slip).
- Air heater fouling, pluggage, and corrosion.
- Ammonia contaminated fly ash.

- Relatively narrow temperature range for maximum effectiveness.

Combined SO₂/NO_x Reduction Processes

Three combined SO₂/NO_x emission control processes close to commercial application in the U.S. are the SNRBTM, SNOXTM, and NOXSOTM processes. All three of these processes have been demonstrated at 5 MWe scale or greater on U.S. coals. The SNRB process is the simplest of these. It incorporates particulate collection but also results in the formation of a solid, low value byproduct. Both the SNOX and NOXSO processes offer the potential for producing marketable byproducts. Currently, commercial applications of the processes rely on the sale of these byproducts to be economically competitive. However, control of SO₂ and NO_x emissions without generation of secondary waste products for disposal is a strong step forward for continued utilization of coal.

The SNRB process is a combination of dry injection for SO₂ control, SCR for controlling NO_x emissions, and fabric filtration for capturing particulate emissions. A 5 MWe demonstration has been completed on a slipstream from a utility boiler firing 3 percent to 4 percent sulfur coal. Emission reduction performance included 85 percent to 90 percent SO₂ removal, 90 percent to 95 percent NO_x removal, and 99.8+ percent particulate capture. The advantages of the process for coal-fired boilers include protection of the SCR catalyst from high dust and SO₂ loadings. SNRB requires operation of the fabric filter at higher than conventional temperatures. Demonstration of commercially acceptable filter bag life remains a critical factor in commercial deployment of the technology.

The SNOX process catalytically removes 95 percent of the SO₂ and 90 percent of the NO_x from flue gas without the use of sorbents and without generating a waste product. The SNOX system is preceded by high efficiency particulate collection, which is critically important to the operating cost of the process. First, the flue gas is heated and ammonia is added before it passes through an SCR reactor. The gas then is heated further before entering a second catalytic reactor, where SO₂ is converted to SO₃. The gas then is cooled and passed to a tube and shell falling film condenser, where the SO₃ condenses to sulfuric acid.

The concentrated sulfuric acid is a relatively high value marketable byproduct. A 35 MWe demonstration of the SNOX technology has been completed in the U.S., treating flue gas from a cyclone boiler firing 3.2 percent sulfur coal. The economic evaluation needs to be completed. The plant consistently achieved 96 percent SO₂ and 94 percent NO_x emission control efficiencies. Sulfuric acid from the plant is used for fertilizer and in a steel pickling operation. A 305 MWe SNOX system has been in operation in Denmark since 1991. This plant burns 0.5 percent to 3.0 percent sulfur coal from a variety of sources. NO_x emissions reduction of 92 percent and SO₂ removal efficiency of 95 percent have been achieved. The sulfuric acid byproduct is used for fertilizer production.

The NOXSO process uses a dry, regenerable sorbent system for controlling NO_x and SO₂ emissions. Both pollutants are removed from the flue gas by adsorption on pellets of high surface area gamma alumina impregnated with sodium carbonate. The loaded sorbent is regenerated by heating with natural gas and steam. NO_x is desorbed and recycled to the boiler flame front, where it is reduced to nitrogen and water. The desorbed SO₂ is partially reduced to H₂S. The combined stream of SO₂ and H₂S is treated to enhance the ratio of H₂S to SO₂ and converted to elemental sulfur in a Claus reactor.

Although there currently is only one supplier of the sorbent, the technology developers are evaluating alternative suppliers to license the patented sorbent manufacturing process. High SO₂ and NO_x adsorption have been demonstrated at a 5 MWe scale. More than 90 percent SO₂ and NO_x removal was obtained. However, the integrated reduction of NO_x by recycle to the boiler and the production of commercial grade sulfur byproducts has not yet been demonstrated. A fully integrated 150 MWe demonstration of the NOXSO process currently is planned for 1996. This system will be designed to remove 98 percent of the SO₂ and 85 percent of the NO_x.

Particulates

Fly ash from the combustion process is collected using one of four major technologies: electrostatic precipitators (ESPs), fabric filters (baghouses), mechanical collectors, and wet scrubbers. With today's removal requirements in excess of 99.5 percent, modern ESPs and fabric filters dominate fly ash collection. Mechanical collectors are still used for specialty applications as preliminary collection devices, especially where fly ash recycle is part of the combustion process, but they are followed almost always by an ESP or fabric filter for final particulate control. Wet scrubbers are no longer used for primary particulate collection because of their high energy requirements for the desired removal efficiencies.

Electrostatic Precipitators

Technology Description

An electrostatic precipitator (ESP) electrically charges the ash particles in the flue gas to collect and remove them. The unit is comprised of a series of parallel vertical plates through which the flue gas passes. Centered between the plates are charging electrodes, which provide the electric field. The collecting plates typically are grounded electrically and are the positive electrode components. The discharge electrodes in the flue gas stream are connected to a high voltage power source, typically 55 kV DC to 75 kV DC, with a negative polarity. As the flue gas passes through the electric field, the particulates take on a negative charge. The negatively charged particles then are collected on the grounded collection plates. Gas velocity between the plates must be low to permit time for the

charged particles to move to the collection plates and to reduce the likelihood of re-entrainment.

The ash layer must be removed periodically. The most common method of removing dry particulates is rapping of the collector plates and electrodes. This consists of suddenly striking the collection surface with this rapping force and dislodging the ash. The dislodged particulates fall from the collection surface into hoppers. It is important to design the ESP to minimize particle re-entrainment. The hoppers are emptied periodically by means of vacuum, pressurized, and mechanical ash removal systems. The balance of the ESP includes the steel enclosure plus inlet and outlet flue transitions with internal flow distribution devices to provide the uniform gas velocities necessary for effective operation.

Electrostatic precipitators can be designed (or sized) to meet virtually all particulate control requirements. Several factors that affect ESP sizing include:

- *Fuel and ash characteristics:* The fuel and ash constituents which are favorable to ash collection and reduce equipment size include moisture, sulfur, sodium, and potassium. Constituents which hamper ash collection, increasing equipment size, include calcium, silicon, and magnesium.
- *Operating conditions:* Gas temperature has a direct effect on the ability of the fly ash particles to accept and hold a charge as well as on the flue gas volume passing through the ESP. ESPs have two optimum operating temperature ranges (below 300°F and above 600°F). However, experience generally has indicated that operation in the higher range results in disappointing performance due to complications from other factors. Gas flow has a direct effect on sizing. There is an optimum gas velocity range within an ESP for maximum performance. Maximum ESP efficiency is achieved when the gas flow is distributed uniformly across the unit cross section. Flow uniformity is achieved typically by installing distribution devices in the flue transition sections immediately upstream and downstream of the ESP. Hopper design also must prevent high velocity areas to avoid fly ash re-entrainment.
- *Particle size and loading:* In addition to the quantity of particulates sent to the precipitator, particle size also affects ESP design and performance. An ESP is less efficient for smaller particles (less than 2 microns) than for larger ones. Therefore, ESP applications with a high percentage of particles less than 2 microns will require more collection surface and/or lower gas velocities to achieve low outlet emissions.

Development Status

ESPs represent the most mature particulate control technology available today and have been the workhorse of the technologies available for coal-fired utility boiler applications

for the last thirty years. Internationally, the ESP also has been the particulate collector of choice for most utilities. Advantages of the well-designed ESP are high total collection efficiency, high reliability, low flue gas pressure loss, resistance to moisture and temperature upsets, and low maintenance.

The current utility operating base of ESPs on U.S. domestic coal-fired boilers includes approximately 890 units representing 277 GWe. These units cover the full range of coals available in the U.S. and some imported coals, as well as the full range of boiler sizes.

Environmental Performance

An ESP is designed to meet a specified particulate collection efficiency. To meet the particulate control regulations for utility units, and considering the resulting high collection efficiency, special attention must be given to details of precipitator sizing and design. The result is a collector which can be operated consistently to meet the outlet emissions requirements. Operating collection efficiencies which exceed 99.9 percent are common on the medium and higher ash coals, with outlet emissions levels of 0.01 lb/MBtu to 0.03 lb/MBtu heat input common on all coals.

A change in regulations or deterioration of precipitator performance may require performance enhancement techniques. These include additional collection surface, gas conditioning, improved flow distribution, control upgrades, and internals replacement. Gas conditioning alters resistivity and other ash characteristics by adding sulfur trioxide (SO₃), ammonia, moisture, or sodium compounds, while the other modifications involve only mechanical hardware changes.

Commercial Impact

Overall, ESPs have been the collection device of choice for many applications. High removal efficiencies are possible, and the units are rugged and relatively insensitive to operating upsets. They represent by far the largest segment of the utility coal-fired boiler system particulate collection market.

However, where low sulfur coal or dry scrubbing are used to minimize SO₂ emissions, ESPs may become larger and less cost-effective compared to baghouses. In the dry scrubbing process, they also are not as effective in enhancing SO₂ removal and sorbent utilization. As particulate collection standards focus more heavily on fine particulate removal, ESPs will require technology development.

Development Needs

The ESP has been the coal particulate collector of choice for many years. ESPs are being

required to remove higher levels of fine particulates (< 10 microns) and selected air toxics. Providing the appropriate data base to ascertain the effectiveness of ESPs at removing these is critical, and identifying equipment changes for optimum control will be important.

Fabric Filters/Baghouses

Technology Description

A fabric filter, or baghouse, collects the dry particulate matter as the cooled flue gas passes through a filter material. The fabric filter is comprised of a multiple compartment enclosure with each compartment containing up to several thousand long, vertically supported, small diameter fabric bags. The gas passes through the porous bag material, which separates the particulates from the flue gas. An inlet plenum distributes the gas to each of the compartments for cleaning. An outlet plenum collects the cleaned flue gas from each compartment and directs it toward the induced draft fan. Inlet and outlet dampers allow isolation of each compartment for bag cleaning and maintenance. Each compartment has a hopper for inlet gas flow as well as for particulate collection and removal by conventional equipment. The individual bags are closed at one end and connected to a tubesheet at the other end to permit the gas to pass through the bag assembly. The layer of dust accumulating on the bag is usually referred to as the dustcake.

Particulate collection takes place through impingement by either direct contact or impaction and dustcake sieving. Minor forces which assist in the collection are diffusion, electrostatic forces, London-van der Waal's forces, and gravity. Once formed, the dustcake, not the filter bag material, provides most of the filtration.

The bags must be cleaned periodically to maintain pressure drop within acceptable limits and to remove the particulates, although a residual dust layer is maintained to enhance collection efficiency. Each compartment is cleaned sequentially. A key design parameter is the "air" or gas flow rate to cloth area ratio (A/C ratio), which is set (1) to minimize unit size and cost, (2) to provide reasonable periods between cleaning cycles, and (3) to optimize bag replacement life.

The three most common bag cleaning methods include reverse air, shake deflate, and pulse jet. The cleaning method is related to the relative size of the A/C ratio and the filtering side of the bag. Both the reverse air and the shake deflate methods are for inside-the-bag filters with gas flow from inside the bag to outside; the pulse jet is for outside-the-bag filters with the flow from outside to inside. The tubesheet on the inside-bag filtering is located below the bags; for pulse jet, the tubesheet is above the bags.

Substantial research and development on bags and their materials has taken place to lengthen their life and to select bags for various applications. The flexing action during

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cleaning is the major factor affecting bag life. Bag blinding, which occurs when small particulates become trapped in the fabric interstices, limits bag life by causing excessive pressure drop in the flue gas. Finishes on the bag surface also are used to make some bags more acid resistant and to improve cleaning.

The most common bag material in coal-fired utility units with reverse fabric filters is woven fiberglass. Typical bag size is 12 in. diameter with a length of 30 to 36 ft. Bag life of three to five years is common. The shake deflate filters also use mostly fiberglass bags. On both of these units, the fiberglass bag is fastened at the bottom to a thimble in the tubesheet. At the top, a metal cap is sown into the bag and the bag has a spring loaded support for the reverse air filters. The upper operating temperature limit is 500°F (260°C) for most fiberglass bags.

In addition to fiberglass, the pulse jet filters commonly use the advanced synthetic materials. Advantages of the synthetic materials include better abrasion resistance and resistance to acid attack. Disadvantages include higher cost and limited temperature capabilities. For the pulse jet filters, the typical bag size is 5 or 6 in. in diameter with a length of 10 to 20 ft.

The key parameters that determine effective fabric filter performance are air/cloth ratio, pressure drop control, cleanability, filter cloth performance, dustcake properties, bag life considerations, and flue gas properties.

Development Status

While not as popular as ESPs, there are more than 72 operating utility coal-fired units in the U.S. accounting for approximately 18 GWe of the operating power base. Use of the fabric filter became popular during the early and mid-1980s for application on the large utility units. However, with few large new units being constructed since that time, development of the fabric filter as an ultra low emission dust collector stagnated. The result has been that actual operating outlet emissions routinely achieved the 0.03 lb/MBtu level, but few units achieved the 0.02 lb/MBtu emission level. The potential exists for lower emissions technology development. Fabric filters have been used extensively in combination with dry scrubber technology to simultaneously remove SO₂.

Environmental Performance

Commercial fabric filters are relatively new to the utility industry, with almost all units installed in the last twenty years. The operating experience with fabric filters for coal-fired boiler applications has been very encouraging. The filters easily meet the 0.03 lb/MBtu standards (usually greater than 99.8 percent removal) required for the new plants built in the 1980s, which utilized low sulfur Western coals for the most part.

Operating utility experience in the United States has been predominantly on reverse gas cleaning, low ratio baghouses (air to cloth ratios of less than 2.0 acfm/ft²). Operating pressure drops varied between 4 to 8 inches water. Bag life has improved considerably, and 4-year bag life on reverse gas units is very common now. Even during bag failures, the target compartments could be brought off-line for bag replacement without a need for boiler shutdown. Most boilers instituted a flue gas bypass arrangement during start-up to avoid condensation and acid dewpoint attacks on the fabric material. Almost all the plants operated at or near visually clear stack conditions.

Development Needs

The areas of development for fabric filters parallel those for ESPs due to the concerns for advancements of the same technologies. Reduced emissions of the air toxics and PM₁₀ (< 10 microns) particulates are legislated, and the filtering mechanism of the fabric filter provides opportunities for greatest reduction. Further integration of combined technologies also offers the prospect for emission reduction.

Mechanical Collectors

Mechanical dust collectors, often called cyclones or multicyclones, have been used extensively to separate large particles from a flue gas stream. The cyclonic flow of gas within the collector and the centrifugal force on the particulates drive the particulates out of the flue gas. Hoppers below the cyclones collect the particulates and feed an ash removal system.

The mechanical collector is most effective on particles larger than 10 microns. For smaller particles, the collection efficiency drops considerably below 90 percent. These collectors frequently have been used for re-injection to improve unit efficiency on stoker firing of coal and oil firing. With stricter emissions regulations, mechanical collectors can no longer be used as the primary control device. However, with the onset of fluidized-bed boilers, there has been a resurgence of mechanical collectors for recirculating the bed material. A high efficiency collector then is used in series with the mechanical one to meet particulate emissions requirements.

Wet Scrubbers

A wet scrubber can be used to collect particulates from a flue gas stream with the intimate contact between a gas stream and the scrubber liquid. For maximum particulate collection, the venturi-type wet scrubber is used to transfer the suspended particulates from the gas to the liquid. Collection efficiency, dust particle size, and gas pressure drop are closely related in the operation of a wet scrubber. The required operating pressure drop varies inversely with the dust particle size for a given collection efficiency; or, for a given dust

particle size, collection efficiency increases as operating pressure drop increases. Due to the excessive pressure drop and the stringent particulate regulations, wet scrubbers are used infrequently as the primary collection device. However, on many coal-fired applications, wet scrubbers are required in series with a high efficiency collector for control of acid gas emissions, so the extra particulate removal is an added benefit. This added removal is of special interest today in connection with the wet scrubber retrofits to existing units with lower efficiency ESPs. Particulate reduction across the wet scrubbers of greater than 50 percent is being reported. The future of the wet scrubber as a particulate collector seems limited to the technology combinations.

Advanced Technologies

As long as particulate matter capture from the combustion generated flue gas is desired, there is a need to continue the pursuit of technologies which maximize this capture. The basic methods of capture are known with electrostatics, filtering, centrifugal forces, and impaction. The integration of these technologies appears as the technology for advancement.

One such advancement is the use of the condensing heat exchanger. With this technology, a shell and tube heat exchanger is used in the flue gas stream to recover heat, and the fine particulates are captured in condensate and removed as the flue gas stream is subcooled.

Another potential technology is the use of additives and fabric filters. This technology can advance the simultaneous collection of particulates and heavy metals with acid gas clean-up. Control of the dust cake on the fabric is required to capture the particulates as well as to provide a large particle surface area for SO₂ acid gas control.

Byproduct Utilization

Sources, Collection, and Handling of Coal-Fired Plant Residue

The American Coal Ash Association (ACAA) prepares an annual summary of coal combustion waste byproduct production and consumption. The information shows that approximately 68 million tons of ash and slag and 19 million tons of FGD sludge were generated in the U.S. during 1990.

In addition, ACAA estimates that over 30 percent of ash byproducts (approximately 21 million tons) and over 1 percent of FGD byproducts (approximately 0.2 million tons) were recycled in 1990 for external market and internal utility uses. Recycling uses included cement and concrete products, structural fills, road base and sub-base materials, asphalt fillers, grit for snow and ice control, blasting grit, asphalt roofing granules, grouting, wallboard, and other miscellaneous applications.

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- *Ash*: The types of ash streams produced by coal-fired boilers are determined by the design of the boiler and the characteristics of the coal being burned. There are five major types of coal-fired boilers in use today: (1) pulverized coal-fired dry bottom, (2) pulverized coal-fired wet bottom, (3) cyclone furnace-fired, (4) stoker-fired, and (5) fluidized bed.

A portion of the ash is collected in the furnace, both directly during combustion and as a result of periodic ash deposition removal. This residue is relatively coarse. The balance of the ash is removed as small diameter particulates (or fly ash) downstream of the boiler in the economizer hoppers, air heater hoppers, and the final particulate collection equipment.

In recent years, U.S. utilities have increased their use of cleaned coal and Western coal in order to lower certain operating and maintenance costs and to meet particulate and tighter sulfur dioxide emission requirements specified in the 1990 Clean Air Act Amendments. The resulting downward trend in ash content is expected to continue, with the 1990 Clean Air Act Amendments further accelerating the use of Western coals as a method of reducing sulfur dioxide emissions.

- *FGD residue*: The type and characteristics of the residue from flue gas desulfurization depend upon the process used (see Chapter III, Part C, Desulfurization); the reagent (usually lime or limestone today); and the final spent reagent processing. For modern wet scrubbers, the byproducts are typically (1) gypsum for commercial use, (2) gypsum for disposal, or (3) a dewatered calcium sulfite sludge which is stabilized by the addition of lime and ash prior to disposal. Dry scrubbers, furnace injection systems, and fluidized bed combustors typically produce a dry mixture of ash, unreacted reagent, and spent reagent.

Solid Waste Storage and Disposal

While approximately 30 percent of ash and a small percentage of FGD sludge are recycled, the majority of coal combustion waste products are not recycled and currently are managed in surface impoundments, landfills, mines, and waste piles. These waste management units may be located on-site or off-site of the power plant they serve and may be owned and operated by the utility or an independent owner/operator. Among the disposal unit alternatives, landfills and surface impoundments are the most widely used. The following is an overview of waste storage and disposal alternatives.

- *Surface impoundments*: A surface impoundment receives coal ash and/or FGD wastes sluiced together with water through a transport system that originates at each coal-fired generating unit. The coal ash and FGD solids eventually accumulate at the bottom of the pond. This process leaves relatively clear water at the surface, which eventually may be recycled for use or cleaned prior to discharge to some other surface water body. In some cases, separate impoundments for fly ash, bottom ash, and FGD solids are used.

The ash solids received from the plant may accumulate in a surface impoundment until it is full, or the impoundment may be dredged periodically for removal to a dry landfill or minefill or wet disposal impoundment. Storage surface impoundments store wastes for less than one year, while disposal surface impoundments store waste for more than one year.

- *Landfills:* Landfills are facilities where dry waste is placed for disposal in or on land. Wastes are transported to these facilities directly from the plant after they are produced or after they are dredged from the storage impoundments that are used as interim facilities. The wastes remain in the landfill after closure. The coal combustion wastes placed in these facilities are dry and have the consistency of soil. As a result, diked walls are not needed to provide stability. Landfills are constructed in a manner similar to surface impoundments, except that excavation usually occurs in segments throughout the active life of a landfill.

The advantages of utilizing landfills for coal combustion waste disposal include increased stability; reduced land use (landfills usually require about 25 percent less space, based on the ratio of dry pounds versus wet pounds of ash that can be packed into a cubic yard); and a decreased possibility that the ash will combine with water to form leachate, which eventually may migrate into soils and groundwater.

- *Other storage and disposal facilities:* Storage waste piles and disposal minefills are used as waste management options by a few selected utilities. Ash waste piles are used primarily as temporary, on-site storage facilities. Waste from these storage piles eventually is brought to a landfill, minefill, or an impoundment for final disposal.

Some utilities in selected regions are able to utilize abandoned mines cost-effectively for ash and FGD waste disposal. This may include the use of mine shafts to fill the areas remaining after the coal or other minerals have been removed, as well as strip-mined areas, which may be filled in a manner similar to landfills.

Current Federal and State Regulations

Since the passage of the Resource Conservation and Recovery Act (RCRA) in 1976, both Congress and EPA have chosen to exempt utility wastes (including fly ash, bottom ash, boiler slag, and flue gas desulfurization waste) from Federal Subtitle C hazardous waste regulation. In the absence of Federal regulation under Subtitle C, states have been granted the authority to regulate utility wastes under Subtitle D non-hazardous waste regulations. This has resulted in a wide disparity in ash disposal practices among the states. Development of uniform national standards could allow for greater use of coal combustion byproducts, help lower costs, and reduce the need for landfills. This recommendation is consistent with the 1992 Energy Policy Act.

Utilization of Coal Combustion Byproducts

• *Coal ash and slag:* The use of coal ash is affected by local and regional factors, including production rates, processing and handling costs, transportation costs, availability of competing materials, seasonal adjustments, and the experience of materials specifiers, design engineers, purchasing agents, contractors, legislators, regulators, and other professionals.

The major markets for coal ash include cement and concrete products, structural fills, road base layers, mineral filler in asphalt, grit for snow and ice control, blasting grit and roofing granules, grouting, coal mining applications, and waste solidification and stabilization.

Fly ash is used widely in concrete and in precast concrete products. In addition to acting as a filler, fly ash provides certain benefits as a result of three key properties:

- Pozzolanic activity (forming cementitious compounds).
- Rounded particle shape.
- Reduced demand for water.

Fly ash may be used in other types of binder in addition to a constituent of concrete and cement. Applications include:

- Masonry mortars for brick walls.
- Plastering for walls.
- Specialist cements -- for example, oil well cements.
- Production of blocks and aggregates.

In these binders, fly ash is mixed with other materials such as Portland cement, lime, gypsum, slag, and alkaline activators. Aggregates or fillers also may be added.

Coal residues have been used as fill material in road construction, bridge repair, and mining and as a general landfill. Fly ash has three main advantages over conventional fill:

- It is lightweight.
- It has self-hardening properties.

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- It provides complete infilling of voids and tunnels.

Fly ash has been used for a number of years as a road construction material. It has been used as fill, sub-base, and road base material. Both cement and lime have been employed to stabilize the fly ash. Several types of slag also have been used in road construction. Bottom ash from pulverized coal-fired power stations has been used as a sub-base material for a number of years and has a number of beneficial properties.

Fly ash, mixed with lime or cement, can be used to stabilize soils. Pozzolanic reactions between fly ash, lime, and water yield products which bind soil particles together. Residues possessing self-hardening properties can be used to stabilize soils without additional additives.

Toxic wastes have been immobilized successfully by stabilization and solidification using fly ash together with water and a bonding and activating agent such as lime, lime and gypsum, or Portland cement. The majority of processes aim to produce a hardened mass with a low leachability. Most applications have been used to stabilize inorganic wastes. Physio-chemical bonding occurs, and additives may be used to make specific ions insoluble. Organic wastes, such as oil sludges, also have been stabilized successfully.

The uses of blasting grit and roofing granules for the most part are specialty applications of boiler slag, with demand being typically regional in character. For example, the largest users of blasting grit are the large shipyards that perform contract maintenance for the U.S. Navy and for commercial shipping lines.

Miscellaneous uses of boiler slag are found in several decorative aggregate applications, such as a sand-substitute in sandtraps on golf courses, and as an aggregate in precast and cast-in-place concrete.

The potential for applications of coal-use residues depends on their physical and chemical properties and the extent to which they might vary. In addition to technical requirements, the following factors influence utilization potential:

- Competition with other materials.
- Attitudes of potential users.
- Subsidies and incentives.
- Equating supply with demand.
- Transport and storage of resources.

- *Flue gas desulfurization byproducts:* Several utilization options have been demonstrated for FGD residues, some of which have reached commercial status. Construction and agricultural uses appear to provide the most important sector for future use. The cost of transporting residues to manufacturing sites or direct to market is a major factor in deciding economic viability compared with natural or competing materials.

Only a small number of utilities in the U.S. sell or utilize the FGD residues they produce. Although the U.S. has the largest number of lime or limestone based wet scrubbers, the production of usable FGD gypsum is very limited. The slow development of a market for FGD gypsum may be attributed to the existence of low-cost and readily available sources of natural gypsum, the availability of disposal sites for FGD and other coal-use residues, and the potential to produce a quantity of FGD gypsum that exceeds the annual consumption of natural gypsum.

Gypsum can be used in a wide range of applications, including pharmaceuticals, plaster bandages, and molding materials. The largest markets for gypsum are for the manufacture of building materials (for example, as an additive in cement). It is estimated that over 20 million tons of gypsum products were used in the U.S. in 1990 and that over 90 percent of the gypsum consumed in the U.S. was used in construction applications.

Many different applications have been developed using FGD gypsum as a building material, including the following applications:

- Wallboard and plasterboard.
- Gypsum plaster.
- Gypsum blocks.
- Floor screeds.
- Setting regulator in cement production.
- Mining plaster.

The cement industry is a large consumer of gypsum. Portland cement contains gypsum used as a retarding agent. The quantity of gypsum incorporated varies depending upon the application but may be up to 5 wt percent. Gypsum granules are ground with cement clinker. FGD gypsum usually needs to be agglomerated before use in cement to ensure a particle size similar to that of natural gypsum. Requirements for the fly ash and chloride content for this application may be less strict than for wallboard applications. In the U.S., this application is considered to offer the greatest utilization potential for FGD gypsum.

Gypsum for cement normally is purchased on the open market rather than from dedicated mines as happens in the wallboard industry. FGD gypsum therefore can compete directly and can provide a stable, local supply with reduced transport costs.

Numerous civil engineering applications have been demonstrated for wet scrubber residues, such as:

- Backfill materials and other mining applications.
- Road base and other uses in road construction.
- Backfill and landscaping material.
- Marine applications.

FGD gypsum has potential for use in the following agricultural applications:

- Conditioning alkaline and saline soils.
- Improving soil permeability.
- Supplying nutritional sulfur.
- Providing catalytic support to maximize fertilizer absorption.

Various building materials applications have been suggested for dry scrubber residues, including the following:

- Artificial aggregates.
- Applications in concrete.
- Manufacture of sand-lime bricks.

Several civil engineering applications that use residues from spray dry scrubbing systems have been investigated. Dry scrubber residues may be suitable for use in the stabilized layer of road foundations. Artificial aggregates manufactured using dry scrubber residues also may be suitable for use in road base and as a filler in asphaltic concrete.

Dry scrubber residues also can be added to pozzolanic fly ash as an activator. A range of engineering materials suitable for backfill and landfill can be made by combining different proportions of fly ash and spray dry scrubber residues.

In Germany, the residues have been used successfully in the mining industry as a filler in packing and backfill operations and as an additive in mining mortars. In North Dakota, spray dry scrubber residues (containing about 75 percent fly ash and 25 percent reaction products) from a 900 MWe power station have been mixed with wet bottom ash to a water content of 20 percent to 25 percent and used to backfill an old lignite strip mine. In Kansas, dry scrubber residues (containing about 80 percent fly ash and 20 percent reaction products) from a 280 MWe power station unit have been mixed with dry economizer ash, moistened with water, and used to create a lining layer (about 1.25 mm thick) for a landfill site.

Development Needs

While continuing efforts need to be made to look at alternate uses of ash (residue) from coal-fired boilers, four areas of power system byproduct use deserve particular emphasis.

- If hazardous air pollutant (HAP) regulations are put into place for coal-fired utility boilers, then larger quantities of HAPs will likely appear in the solid residue or byproduct streams. The exact species need to be identified, stability evaluated, environmental behavior and leachability assessed, and impact on byproduct utilization defined.
- Byproducts from many Clean Coal Technologies combine ash, spent sorbent, and unused sorbent. Re-use or disposal technologies for these solids streams are different from those for ash or gypsum alone and deserve further work to characterize the material, expand re-use, and assess the environmental impact.
- Dibasic acid, formic acid, and other wet FGD scrubber additives may see increased use as SO₂ removal enhancers. The effects of these additives on the production of gypsum and other byproduct streams need to be confirmed.
- In view of the inconsistency among states regarding regulations for handling utility wastes, development of national standards could allow for greater use of coal combustion byproducts, help lower costs, and reduce the need for landfills.

Hazardous Air Pollutants (HAPs)

Framework for HAP Assessment of Coal-Fired Utility Boilers

Title III of the Clean Air Act Amendments (CAAA) of 1990 mandated that the Environmental Protection Agency (EPA) require U.S. industrial facilities (except electric utility plants) which emit more than 10 tons per year of any one of, or 25 tons per year of any combination of, 189 specified "hazardous air pollutants" (HAPs) to apply

“maximum achievable control technology” (MACT). Title III also mandated that the EPA evaluate emissions of HAPs (also called “air toxics”) from electric utility stations to assess their potential impact on public health and, if required, the level of control needed. Using tests conducted by DOE, other industry sources such as the Electric Power Research Institute (EPRI), and other literature sources, EPA is expected to issue a report to Congress in November of 1995 covering electric utility steam generating plants over 25 MWe.

Determination of the risks and implications of HAPs from utility steam generating units is an extremely difficult and complex task. The combination of circumstances which influences the impact of HAP emissions is multi-faceted, including a wide range of creation mechanisms, the transportation and fate in the atmosphere, and the effectiveness of existing emission control technologies. A particularly challenging problem is the accurate, reliable, and repeatable measurement of HAPs in the extremely low concentrations found in flue gas from utility electric generating plants.

HAPs consist, by definition, of 189 trace metals, organic compounds, and inorganic compounds. The elements which can lead to HAPs are present in virtually all fuels and are released or created during the combustion process. The quantity released will be dependent upon the as-fired fuel chemistry, combustion process, combustion equipment, and emissions control technology. Depending upon the combustion (or gasification) process, the elements are released as gases, liquids, and/or solids. System operating conditions such as reducing/oxidizing environment, gas-phase composition, temperature, and pressure influence how the HAPs are partitioned through the system.

Of particular importance for postcombustion control technologies is the volatility of the elements or compounds. Elements/compounds with low volatility (for example, thorium and scandium) are dispersed relatively evenly as solids throughout the boiler bottom ash or fly ash. A second class of elements and compounds (for example, chromium, nickel, arsenic, cadmium, lead, and zinc) are vaporized as part of the high temperature combustion but are condensed during their passage through the boiler system. The HAPs tend to show increasing enrichment with declining particle size. Finally, a third class of elements (for example, mercury, selenium, fluorine, and chlorine) are vaporized during combustion and remain in the vapor phase through the system.

The single most important consideration in the evolution of appropriate HAP control from electric utility steam generating systems is the development of accurate, reliable, and repeatable experimental methods and quality control protocols to test for and monitor HAPs. HAPs found in flue gas typically are measured in parts per billion (ppb) or parts per trillion (ppt). These levels compare to hundreds and thousands of parts per million (ppm) for currently regulated sulfur dioxide (SO₂) and oxides of nitrogen (NO_x). In addition, the exact form and chemistry leading to various emissions are not well

understood for many of the HAPs (for example, mercury). These factors have led to large uncertainties and inconsistencies in historical data.

To meet the need for accurate and consistent data, DOE has been conducting its "8-Plant Study" (see page 92, Table III-C), and EPRI has been conducting its "Power Plant Integrated Systems: Chemical Emissions Study (PISCES)."

It is expected that this work will form a substantial portion of the basis for eventual EPA risk assessment. While these studies are not yet complete, preliminary results are providing insights which will be very useful in defining the appropriate strategies for control. Significant observations to date indicate that:

1. The level of emissions found in the DOE and EPRI data are considerably less than those for earlier literature data. In many cases, the HAPs concentrations are at or below the limit of detection.
2. For many of the trace metals, the current data are one to two orders of magnitude lower than the historical data.
3. Ranges in the emissions measured are much smaller and more consistent for the current DOE and EPRI data, indicating significant improvements in test methods and quality control protocols.
4. As discussed below, existing particulate control equipment (ESPs and fabric filters) and flue gas desulfurization equipment (wet and dry scrubbers) potentially can be very effective in reducing the emissions of many hazardous air pollutants.
5. Difficulties remain in effecting material balances for pollution control subsystems and entire power plants, obtaining consistent results from several test methods, and monitoring very low levels of some HAPs.

Performance of Existing Utility Boiler Emissions Control Systems

Based upon the DOE and EPRI studies, final hazardous air pollutant emissions potentially can be reduced as the elements and compounds pass through the power system. While the details of recovery by equipment type and HAP species have not yet been fully defined, a general picture is emerging. The degree of reduction depends upon species to be controlled, the power plant design, and the environmental equipment employed. The following subsections review some of the key observations about each potential control step.

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TABLE III-C

**EMISSION FACTOR RANGES FOR TRACE METALS AND SELECTED
ORGANICS FROM DOE COAL-FIRED POWER PLANT PROGRAM [6.5]**

Trace Metals (lbs/10 ¹² Btu)			Trace Organics (lbs/10 ¹² Btu)		
<i>Metal</i>	<i>DOE</i>	<i>Ref. 6.4</i>	<i>Organic</i>	<i>DOE</i>	<i>Ref. 6.4</i>
Antimony	<0.1 - 2.4	N/A	Benzene	3.4 - 170	N/A
Arsenic	0.1 - 42	<1 - 860	Toluene	2.0 - 24	N/A
Beryllium	<0.1 - 1.4	<1 - 32	Naphthalene	<0.1 - 1.9	*
Cadmium	<0.1 - 3.0	1 - 490	Anthracene	(3.0 - 20) 10 ⁻³	*
Chromium	<0.1 - 51	10 - 5000	Phenanthrene	(2.0 - 31) 10 ⁻²	*
Cobalt	<0.1 - 6.8	N/A	Pyrene	(3.0 - 40) 10 ⁻³	*
Lead	0.6 - 29	N/A	Benzo(a)-pyrene	(2.0 - 12) 10 ⁻⁴	*
Manganese	1.1 - 22	30 - 2400	Formaldehyde	1.4 - 57	63 - 2100
Mercury	0.5 - 14	1 - 22	2-Butanone	3.7 - 16	N/A
Nickel	0.3 - 40	1 - 2500	2,3,7,8-TCDD	(8.1 - 25) 10 ⁻⁷	N/A
Selenium	<0.1 - 130	N/A	2,3,7,8-TCDF	(6.6 - 9.9) 10 ⁻⁷	N/A

* The literature data are classified as Polycyclic Organic Matter and range from 0.03 to 565 lbs/10¹² Btu.

Coal Cleaning

Most coal from U.S. underground mines is cleaned through washing to reduce ash and sulfur content. HAPs which are "extraneous" in nature and are not chemically bound to the coal carbon matrix (especially trace metals) generally can be reduced to some level by coal cleaning, depending upon the cost and the acceptable amount of coal rejected in the refuse.

Coal cleaning typically involves initial size reduction, screening, removal of foreign material, and some form of washing (see Chapter III, Part A). Besides the trace metals which are removed as part of this process, washing also can remove some of the soluble compounds such as chlorides when they are not chemically bound to the coal matrix. EPRI PISCES data tend to indicate that many of the trace elements can be removed at a level of 25 percent to 75 percent using coal cleaning. One key to effective removal is the coal size reduction. In general, smaller mean coal particle sizes result in the more ash and HAPs being removed during cleaning (especially the soluble compounds). However, greater size reduction also tends to increase operating cost and increase the quantity of coal sent to the reject or refuse pile.

Particulate Control: Electrostatic Precipitators and Fabric Filters

Preliminary DOE and EPRI results indicate that particulate control systems (see Chapter III, Part C, Particulates) significantly reduce the levels of many heavy metals in the flue gas streams. Some metals, including arsenic, cadmium, chromium, lead, and nickel, can be removed with greater than 90 percent efficiency. The measurement data also indicate that fabric filters can achieve reductions of over 99 percent for such heavy metals as arsenic. The notable exceptions are mercury and selenium.

A key performance parameter is the volatility of the species. Very low volatile species such as beryllium and manganese generally are dispersed evenly in the ash and are collected at the overall ESP collection efficiency, 99.5 percent or higher in new units.

Species with medium volatility tend to vaporize during combustion but then condense onto ash particles as the flue gas cools. Because of the higher surface-to-volume ratio of small particles, such condensing materials tend to be enriched in the smallest particle size fraction. This reduces the effectiveness of ESPs in their collection of HAPs.

ESPs are very effective at collecting particles larger than 10 microns but significantly less effective for particles less than 3 microns. Fabric filters, however, do not exhibit as significant a decline in collection efficiency as a function of particle size and have been observed to exhibit higher collection efficiencies for the trace elements which tend to be enriched in the smaller particle fraction. Trace elements exhibiting the most enrichment in fine particles are cadmium, molybdenum, arsenic, lead, chromium, and antimony. In general, it appears that conditions that promote lower temperatures and the improved removal of combustion and postcombustion particulates and aerosols also serve to control many of the heavy metals.

Species with the highest volatility (mercury and hydrogen chloride, for example) remain in vapor phase throughout the power system gas path and are not collected efficiently in particulate control equipment.

Flue Gas Desulfurization: Wet and Dry Scrubbers

Wet and dry flue gas desulfurization systems (see Chapter III, Part C) usually are used in conjunction with particulate control equipment in large coal-fired steam generating plants. The scrubber systems themselves are relatively poor particulate collection devices, relying primarily upon "impaction" to collect the solids. Thus, they are not viewed as primary devices for collection of solid phase HAPs (most trace metals and non-volatile organics) from utility boiler systems. They do, however, remove some additional solid material, as noted in the DOE and EPRI PISCES studies, and, in the case of dry scrubbers, can reduce the operating temperature of the flue gas stream, thereby enhancing the HAP collection efficiency of the downstream particulate collector.

Wet and dry FGD scrubbers also offer the potential to control vapor-phase HAPs. Scrubbers can be effective in controlling chlorine emissions from coal-fired plants. Ninety-five percent of the chlorine is released as vapor phase hydrogen chloride (HCl) during the combustion process.

The EPRI data indicate that, if required, existing coal-fired plants equipped with wet or dry FGD potentially can achieve over 90 percent removal of HCl. Dry scrubbers are used routinely to remove HCl from municipal waste combustors. However, HCl concentrations in the flue gas are substantially higher than in coal-fired plants. The ability of wet and dry FGD systems to control other volatile HAPs is under evaluation and requires further study.

FGD Systems and Mercury

Mercury received special attention during the drafting of the CAAA sections on air toxics because of mercury's potential to accumulate in the food chain and lead to a health risk. It is more volatile than other trace metals and is emitted in relatively small quantities. Mercury levels in U.S. coals vary, although the widespread practice of coal washing to reduce ash is believed to bring coal mercury levels for most coals fired in power plant boilers to around 0.1 part per million.

During combustion, elemental mercury is formed as an atomic vapor. During the cooling process, some of this mercury reacts with other flue gas constituents to produce a number of compounds, in particular mercuric chloride (HgCl_2). The difficulties observed in both the DOE and EPRI studies in obtaining reliable mass balances indicate the final transformations are not well understood. Mercury removal in wet FGD systems has been reported to be 10 percent to 90 percent. This wide range is due in part to the difficulty in identifying the forms of mercury present. Further development efforts will be required to better define the final mercury transformations and the most effective control methods.

Emerging Control System Option and Upgrades

The effective control of the wide range of HAPs from coal-fired power plants has only recently received focused attention and study. A particular challenge is the relatively low concentration of HAPs in the flue gas stream, especially compared to the existing experience on municipal waste combustors where concentrations are substantially higher. Some of the control options under evaluation include:

- Use of activated carbon filters to collect vaporous HAPs, especially mercury.
- Injection of activated carbon powder in spray dry/fabric filter systems and boiler/fabric filter systems to reduce mercury emissions.
- Additives for wet and dry FGD systems to improve HAP removal efficiency.
- Optimization of existing particulate and SO_2 control systems to remove more HAPs.
- Use of circulating bed dry scrubbers and moving bed scrubbers to remove HAPs.

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- Applications of some emerging clean coal technologies to remove HAPs.
- Application of condensing heat exchanger systems to minimize emissions of HAPs while also recovering waste heat.

The use of activated carbon to remove mercury has shown some promise, although present results are inconsistent. Activated carbon currently is used on some municipal waste combustion (MWC) facilities in Europe to control mercury emissions. However, mercury concentrations in the MWC flue gas are typically one to two orders of magnitude higher than in current coal-fired utility steam generating units.

Results from activated carbon injection in MWC systems which also use a spray dryer and fabric filter showed an increase from 69 percent removal without carbon injection to 91 percent to 95 percent with injection. EPRI pilot tests of activated carbon injection in conjunction with a pulse-jet fabric filter indicated better than 90 percent removal with injection of 4,000 parts carbon per part mercury. Other tests, however, have shown no measurable mercury removal.

Additional research is thus required to determine what process parameters influence recovery and under what conditions activated carbon is a cost-effective solution to mercury recovery. Related work will also be required to determine what happens to the recovered mercury. A wide array of additional options are also under evaluation.

Development Needs

Complete the current DOE and EPRI studies (including CCT projects) to better define the magnitude of HAP emissions from coal-fired steam generating plants. Additional work will be warranted following submittal of the initial results to the EPA in order to expand the data base available.

Continue development of experimental methods and test protocols to improve the accuracy, reliability, and repeatability of trace element identification in coal and in HAP identification in the combustor flue gas stream.

Perform systematic studies of existing air pollution control equipment (ESPs, fabric filters, dry scrubbers, and wet scrubbers) under controlled conditions to (a) better understand the behavior of the HAPs; (b) optimize removal performance; (c) identify performance

enhancements (chemical or physical) of existing equipment; and (d) optimize overall system performance.

Demonstrate promising technologies for the control of selected HAPs where further control is required. One example is the use of activated carbon systems to remove mercury and other volatile HAPs. A key will be demonstration of the economic viability and reliability of these control technologies.

Carbon Dioxide Controls

Carbon dioxide (CO₂) is classified as one of the major greenhouse gases, which also include methane, nitrous oxide, halocarbons (predominantly chlorofluorocarbons), and other trace gases. The contribution of greenhouse gas emissions from all human activities (such as fossil fuel combustion, transportation, and industrial processes) is very small compared to total releases from natural sources such as the combustion of vegetation in wildfires and the biological processes of animals and microbes. However, there is concern that emissions of greenhouse gases including CO₂ from human activity (anthropogenic CO₂ emissions) could contribute to changes in the Earth's environment. Scientists as a whole are still sharply divided on this issue and on the magnitude of the possible effects.

Anthropogenic carbon dioxide is emitted primarily from the burning of fossil fuels (natural gas, oil, and coal) for transportation, process heating, electrical power production, and other applications. CO₂ emissions from U.S. coal-based electricity production represent about a third of total U.S. emissions from the burning of fossil fuels and about 7 percent of worldwide fossil fuel derived emissions.

Options for limiting CO₂ emissions from coal-fired power plants generally include:

- Reducing energy demand through conservation.
- Fuel switching to lower carbon content fuels or to non-carbon energy sources, such as nuclear, solar, and geothermal.
- Fuel processing, such as gasification and hydrogen shift to permit removal of CO₂ from the high pressure, high concentration fuel gas stream prior to ultimate fuel combustion.
- Increasing power plant efficiency to consume less fuel for the same power generation.

- Employing postcombustion flue gas cleaning technology to isolate and ultimately dispose of the CO₂.
- Reforestation or other biological absorption of CO₂.

Postcombustion control of CO₂ involves the removal of CO₂ from the flue gas stream, collection and preliminary CO₂ processing, transportation to an ultimate disposal location, and disposal with long-term isolation from the environment. Each of these phases includes a significant cost and degree of technical challenge. Transportation and long-term disposal may be the most significant issues.

The balance of this section reviews the technologies which potentially can be used to remove CO₂ from the combustion products stream: absorption, adsorption, cryogenic recovery, and membrane separation. Significant technical challenges focus on reliable removal of the relatively low concentration CO₂ from a large flue gas volume which also includes a variety of detrimental contaminants. The final "waste" generated is CO₂, which must be cleaned, dried, and compressed prior to shipment and disposal.

The technology description and development status are discussed below for each technology, following which environmental performance, commercial impact, and development needs are addressed for the entire group of technologies. As discussed later, postcombustion recovery of CO₂ is very expensive, has a major impact on power production, and would rely on permanent disposal of large quantities of CO₂. Other alternatives for CO₂ emission reduction currently are more attractive. The discussion closes with a brief review of CO₂ emissions from limestone based SO₂ removal systems.

Absorption

Technology Description

Absorption processes can scrub the flue gas in a tower continuously to remove CO₂ by chemical or physical means. The loaded solvent stream is sent to another vessel where the CO₂ is released by the application of heat, regenerating the solvent and producing a concentrated gas stream. In a chemical system, a solvent such as monoethanolamine (MEA), diethanolamine (DEA), or hot potassium carbonate forms a weakly bonded compound with the CO₂ from the flue gas.

These processes can be used at low CO₂ concentrations typically found in power plant flue gas, but the gas stream must be free of SO₂, O₂, and particulates. NO_x also would form heat stable salts with MEAs that would not be easily recoverable. The CO₂ also can be physically absorbed in a solvent according to Henry's Law and then regenerated by heat or pressure reduction. A typical physical absorption solvent is Selexol® (dimethyl ether of polyethylene glycol).

Development Status

Many absorption processes are in full-scale operation for removal of acid gases (including CO₂) from natural gas reservoirs, ammonia production plants, and other applications. Several CO₂ recovery plants have been installed downstream of "clean" gas-fired processes to recover CO₂ for enhanced oil recovery, urea plant feed, and foodgrade feed. A variety of processes have been tested only on a pilot scale. However, none of these has been applied commercially to coal-fired systems.

Adsorption

Technology Description

Typical gas-solid adsorption processes for CO₂ removal would pass the flue gas through fixed beds of alumina, zeolite, or activated carbon. Multiple parallel vessels would be required so that one can be in regeneration while another is in service.

Four methods are used commercially for regeneration of the adsorbent. Pressure swing regeneration (PSA) lowers the pressure in the vessel containing the saturated bed until the trapped gases are released. Thermal swing adsorption (TSA) uses high temperature regeneration gas to drive off the trapped gases. The third method uses a stream that does not contain any of the trapped gas to "wash" the bed. The final method uses a gas to replace the trapped gas and is essentially a chromatographic procedure.

For power plant applications, the PSA regeneration cycles are more attractive than TSA cycles because they are relatively short, typically measured in seconds, require only one-half to one-third the energy, do not dilute the product gas, and are about one-tenth the physical size. Note that unless a vacuum will be used to regenerate the adsorbent in a PSA system, the flue gas must be compressed and cooled before entering the tower.

Development Status

A variety of processes are available. However, their high power costs make current state-of-the-art adsorption technology for CO₂ capture unattractive.

Cryogenic Technology

Technology Description

Cryogenic systems use a low temperature physical approach that separates CO₂ by multi-stage compression/cooling with condensation. Since water also will condense, the gas must be dried before being cooled. The minimum CO₂ mole fraction in the exit gas phase is achieved at low temperatures and high pressures. This system has been proposed for an IGCC plant, although it does not appear particularly attractive.

Development Status

Cryogenic separation of CO₂ from utility boiler combustion products is very energy intensive, with estimates of the energy penalty in excess of 50 percent of coal input. It therefore has received little attention to date.

Membrane Technology

Technology Description

Gas separation membranes rely on a difference in physical or chemical interaction between the components of a gas mixture and the membrane material, causing one component to permeate through the membrane faster than another. The CO₂ dissolves in the membrane material and diffuses through it to the other side. The quality of the separation depends in part on the selectivity of the membrane. Gas absorption membrane systems are used as contacting devices between the gas phase on one side and an absorption liquid on the other. The selectivity of the process depends on the liquid, not the membrane.

Development Status

Flue gas streams are composed of many species with different concentrations, membrane solubilities, and membrane permeabilities. Therefore, the development of CO₂ selective

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membrane systems for coal-fired boiler combustion products is difficult. Membranes are also sensitive to particulate fouling. None of these options currently is nearing commercial status for power plant application.

Environmental Performance

Chemical absorption has been judged to be the most promising technology to scrub CO₂ from the flue gas of coal-fired power plants. While it has been used on a few gas-fired power systems where a ready market (enhanced oil recovery, urea production, or food/beverage application) justified recovery and use of CO₂, it has not yet been applied commercially to coal-fired plants.

The process requires the flue gas to be free of SO₂, O₂, hydrocarbons, and particulates and remains very energy intensive and expensive. Preliminary estimates for a retrofit of an existing plant indicate a reduction in power production of over a third and capital costs comparable to the initial capital cost of the power plant itself. These estimates assume the resolution of the transportation and disposal issues. Current state-of-the-art adsorption, cryogenic separation, and membrane technologies all are even more energy intensive and economically unattractive.

Broad based CO₂ control through postcombustion removal is not expected to become attractive in the near term. Longer term application will be limited until:

- All other less expensive CO₂ control measures, including power plant efficiency gains and conservation measures, have been effectively exhausted.
- Permanent long-term disposal issues, including environmental impacts, are resolved.
- Extensive pipeline system or alternate transportation system is put into place.
- Substantial improvements in the performance and costs of CO₂ recovery process are made.

Therefore, at the current time, power plant improvements to control CO₂ emissions will likely focus on efficiency changes such as higher steam pressure and temperature conditions, improved back-end waste heat recovery, and alternate power cycles.

Development Needs for All CO₂ Technologies

The following issues should be resolved: (1) the impact of CO₂ on environmental change; (2) the viability of large-scale CO₂ permanent storage/disposal (including environmental impact and risk issues); (3) the economic attractiveness of other methods of CO₂ reduction, such as general conservation, and improvements in power production efficiency; and (4) the viability of large-scale CO₂ transport systems. Development efforts should focus on advanced chemical solvents which improve performance, control cost, and provide for adequate sequestration. If the resolution of these issues justifies further CO₂ reduction, the development efforts could be followed by large-scale demonstrations.

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D. Integrated Coal Gasification Combined Cycle

Integrated coal gasification combined cycle (IGCC) power generation technology is one of the cleanest and most efficient means of producing electricity from coal. IGCC also offers flexibility:

- In meeting most current and future environmental standards.
- In allowing a variety of fuels.
- In utility planning (phased construction, repowering, coproduction).

The National Research Council, an arm of the National Academy of Sciences, noted in a report that IGCC technology "has the potential for being the preferred coal-based technology considering all environmental emissions, including CO₂."

Technology Description

Coal gasification combined cycle takes an approach that is fundamentally different from that of conventional combustion technologies to produce electricity cleanly from coal.

In the gasification process, coal reacts under controlled conditions to produce a fuel gas which is cleaned prior to combustion in a combined cycle power generation system. Therefore, coal gasification is a "precombustion" gas clean-up technology. Potential pollutants then are converted to marketable byproducts.

The combined cycle system has two basic components. High efficiency gas turbines, widely used in power generation today, burn the gas to produce electricity. Exhaust heat is recovered to power traditional high-efficiency steam turbines that generate additional electricity. It is also possible to add topping systems such as fuel cells and supplemental bottoming cycles.

Gasification technology can accept a wide variety of coals, ranging from low sulfur sub-bituminous Western U.S. coals (lignite) to high sulfur bituminous coals. Low value fuels such as petroleum coke, heavy oil, and refinery wastes also can be gasified to provide clean energy while solving potential disposal problems. Biomass and sewage sludge also are potential feedstocks.

Use of a combined cycle system allows an IGCC power plant to be inherently more efficient than a conventional pulverized coal plant. This reduces both fuel costs and the amount of CO₂ produced per kilowatt hour of electricity generated. Current IGCC technology can achieve a heat rate of 8,000 Btu/kWh to 8,500 Btu/kWh. Future improvements in IGCC power plants, incorporating advances in turbine technology, promise even greater efficiency, with heat rates in the range of 7,000 Btu/kWh to 7,500 Btu/kWh.

As a result of its efficiency advantage, a typical IGCC plant using current technology will produce 15 percent to 20 percent less CO₂ than a comparably sized conventional pulverized coal-fired plant with scrubbers.

Development Status

Coal gasification combined cycle technology benefits from years of research, development, and demonstration and is now in full-scale pre-commercial operation. IGCC power generation plants combine two proven technologies.

- Coal gasification has been in commercial operation for years in plants around the world: in North America, Europe, Asia, and Africa. These plants, processing more than 100,000 tons of coal per day, produce gas for the manufacture of a variety of products, such as liquid fuels, substitute natural gas, ammonia, and methanol, as well as for IGCC power generation.
- Combined cycle power generation technology, based on highly efficient combustion

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turbines, is also in wide commercial use, with some 60,000 megawatts of installed capacity worldwide operating on a variety of fuels.

The capital cost of a mature IGCC plant may become comparable to a conventional coal-fired power plant designed to meet increasingly stringent clean air permitting requirements. The combination of low fuel costs, high efficiency, and environmental performance makes IGCC a cost-effective source of power.

Several major IGCC pre-commercial projects are in operation or under construction in North America, Europe, and Asia. Many more are in various stages of planning and design.

Destec Energy, Inc., and PSI Energy, Inc., are building the 265 megawatt Wabash River Coal Gasification Repowering Project in Indiana. The project will start up in 1995 and will demonstrate, in a commercial setting, advancements in Destec's coal gasification process using coals with as much as 5 percent sulfur. Destec has been operating a 161 megawatt power plant using its coal gasification technology at a Dow Chemical Company plant in Plaquemine, Louisiana, since April 1987.

The Demkolec Project, the world's first commercial scale integrated IGCC plant, is based on the Shell Coal Gasification Process. The plant, which operates in the Netherlands near the town of Buggenum, has a net output of 253 megawatts. The application of the Shell technology by Demkolec (a subsidiary of the Dutch Utility Generating Board) follows successful operation by Shell of coal gasification demonstration plants in the United States and Europe. Other commercial IGCC projects based on the Shell process currently are under development.

Tampa Electric Company has licensed the Texaco Gasification Process for a 260 megawatt project in Polk County, Florida. The Texaco Process was used for the Cool Water Coal Gasification Program, the world's first commercial demonstration of IGCC, which operated from 1984 to 1989. Texaco develops IGCC projects and licenses its gasification technology for both power generation and chemical production using coal and other feedstocks, including heavy oil residues, petroleum coke, and Orimulsion™.

Environmental Performance

The Federal Clean Air Act Amendments of 1990 (CAAA) set strict limits on sulfur dioxide

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(SO₂) and nitrogen oxide (NO_x) emissions (so-called "criteria air pollutants") from coal-based power plants. An IGCC power plant reduces emissions of these compounds to levels far below these and any other foreseeable requirements.

With IGCC, sulfur removal efficiencies of 99 percent are readily achievable. Emissions of SO₂ and NO_x from an IGCC plant are a small fraction of Federal standards. These low levels of emissions have a direct economic value under the emissions allowance provisions of the CAAA.

Syngas typically is scrubbed to remove particulates to very low levels prior to combustion. Therefore, particulate emissions from a syngas-fired combined cycle plant are expected to be similar to those of a natural gas-fired unit.

IGCC technology produces marketable byproducts rather than solid wastes requiring disposal. This eliminates a major environmental impact associated with coal combustion. Sulfur is removed from the fuel gas and recovered in pure elemental form. Sulfur is a commodity traded on world markets. The high temperature of a slagging gasifier converts ash and other solid matter in the coal into an inert, non-leachable, granular slag. The slag is nonhazardous and can be used as an aggregate for road and building materials.

Title III of the 1990 Clean Air Act Amendments identifies 189 "hazardous air pollutants" (HAPs) to be regulated under the Act. The Environmental Protection Agency is required to identify specific sources and develop control standards for HAPs based on stringent "maximum available control technology" (MACT). A regulated source will be subject to MACT standards if it emits more than 10 tons per year of any single HAP or 25 tons per year of any combination of HAPs (see Chapter III, Part C, Hazardous Air Pollutants).

Electric utilities have not yet been subjected to Federal regulations for HAP emissions, pending the outcome of an EPA study. If, however, coal-based power plants are identified as potential major sources of HAP emissions, application of MACT standards could impose significant additional costs, depending on the control technology employed.

One advantage of IGCC technology is that HAP emissions are minimized without the need for add-on devices. Detailed measurements at Shell's coal gasification plant in Texas (SCGP-1) clearly demonstrated that the great majority of the metals in coal which, if not removed, could lead to HAP emissions are encapsulated in the inert slag, rendering them harmless.

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Total HAP emissions from a nominal 500 megawatt IGCC power plant are projected to be less than one ton per year, well below the MACT threshold set by the CAAA.

In the past, DOE and other government agencies (such as the Synfuels Corporation) have been very supportive of IGCC technology development. Funding covered most aspects of technology development from construction of pilot plants like the Westinghouse and IGT fluidized bed gasifiers to demonstrations of gasification at Destec's LGTI plant and IGCC at Cool Water.

Currently, DOE is supporting IGCC technology development through the Clean Coal Technology (CCT) program, advanced gasification technology design program, and advanced gas turbine design program. Under CCT, DOE is providing partial funding (approximately 40 percent of up to \$3.0 billion) to demonstrate several gasification technologies, including Texaco, Destec, ABB/CE, British Gas/Lurgi, KRW, and Tampella. This complements planned European programs to demonstrate the Shell, Prenflo, and High Temperature Winkler (HTW) technologies.

The advanced gasifier program allows operation of four large-scale R&D facilities. These facilities support commercial market entry technology improvement and testing in the areas of:

- Advanced air blown gasification.
- Transport gasifier.
- Hot gas clean-up.
- Hot gas desulfurization.

Advanced gas turbines should allow IGCC technology to reach higher efficiency. Current goals are commercial demonstration of a natural gas combined cycle with over 60 percent (LHV) efficiency by the year 2000. This will allow over 50 percent (HHV) IGCC efficiency sometime between 2000 and 2010.

Commercial Impact

Based on potential environmental and performance advantages and competitive cost, IGCC

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has the potential to obtain the majority share of new coal-based power generation capacity. These advantages, combined with the potential for significant technology enhancement, could make IGCC very attractive.

In addition, IGCC allows phased construction of gasification plants for new or existing natural gas-fired combined cycles, repowering of existing coal plants, and coproduction. These options provide additional avenues for IGCC market penetration.

Phased IGCC construction involves the staged construction of combined cycle units, followed by later addition of gasification units. Such a construction schedule allows enough flexibility to take advantage of low near-term gas prices while providing a hedge against future higher fuel prices through use of low-cost coal and/or alternate fuels, such as petroleum coke.

The Department of Energy estimates that by the year 2000, 44 percent of U.S. coal-fired capacity will be at least 30 years old. In addition to future market penetration, IGCC technology can be used to repower these aging coal-fired power plants to extend their useful lives, increase capacity, reduce emissions, and avoid the need to find and obtain approvals for new sites.

When additional capacity is needed, IGCC repowering will give better performance than retrofitting an older plant with SO₂ and NO_x emissions controls. For a typical situation, repowering with IGCC can significantly increase a plant's generating capacity and dramatically reduce emissions from the levels of the original smaller plant.

For example, total emissions of SO₂ and NO_x can be reduced by 95 percent and 90 percent, respectively. The generating capacity of the repowered plant will be triple that of the original facility. Because of IGCC's greater efficiency, CO₂ emissions per unit of electricity also will be reduced.

The gas from a gasification plant can be further processed using commercially available and developing technologies to manufacture liquid fuels for on-site energy storage and utility system peaking. Substitute natural gas, fertilizers, hydrogen, chemicals, and motor fuels also can be produced from the fuel gas as markets warrant. Production and sale of these commodities -- along with the generation and sale of electricity -- can provide added revenues to an industrial facility using gasification technology.

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Development Needs

To assure significant market entry and commercial deployment, it is important that IGCC technology components continue to evolve and achieve a concurrent decrease in production cost. This is particularly true for technology enhancement, such as advanced gasification system design, coproduction, hot gas clean-up, and advanced gas turbine systems. Therefore, R&D efforts and funding should be focused in these areas and tied to cost reduction.

In addition, it is important that momentum started and maintained by the current DOE CCT program continue through development of additional near-term projects, either domestic or international. This will help to establish commercial acceptance and market entry. Therefore, government risk-sharing or other appropriate incentives (at reduced levels from the CCT program) are justified.

CHAPTER IV

OTHER ADVANCED POWER SYSTEMS

A. Advanced Gas Turbines and Combined Cycle Systems

Over the past several decades, the U.S. has held a global lead in gas (combustion) turbine technology. This cutting edge superiority enjoyed by the industry is due primarily to the tremendous financial impetus of the U.S. Department of Defense (DoD) for high performance gas turbine engines in sophisticated aircraft and aerospace applications.

Gas turbines developed mainly with funds from DoD and manufacturers also are used in commercial aviation and for land-based power generation and cogeneration. U.S. gas turbine manufacturers provide jobs to approximately 671,000 employees, half of whom are in production. Gas turbines also help the U.S. balance of trade, with the U.S. as the net exporter. In 1991 the U.S. had over \$2 billion of net exports from the global sales of gas turbines for commercial and land-based applications.

The shrinking U.S. military budget, growing power generation demand worldwide, and increased support of advanced gas turbine research and development by the German, Swiss, French, and Japanese governments have posed the most serious challenge to the U.S. gas turbine industry. Japan is aggressively funding advanced turbine development programs. The Advanced Turbine Systems program sponsored by the U.S. Department of Energy and coordinated with the Electric Power Research Institute, the Gas Research Institute, and the U.S. Environmental Protection Agency (EPA) serves as a major step toward maintaining this technological leadership edge by the U.S. gas turbine industry.

Coal-fired power plants will continue to produce the bulk of the electricity. Gas-fired generation, however, is expected to double between 1990 and 2010, from 362 billion kilowatt hours to 634 billion kilowatt hours. This projection is based on gas and coal cross-over prices in the future. It is predicted that during the first ten years, gas-fired gas turbine/combined cycle systems will represent approximately 53 percent of the total additions. This projection is based on the fact that gas turbines require a short construction cycle to bring them on line. Coal-fueled power plants will dominate the following ten years, allowing the longer construction time required to bring them on line.

On the global scene, however, it is expected that a sizable increase in electric generating capacity will take place, most of which will be coal-based. The latest projections indicate that global energy consumption of coal will increase by approximately 35 percent between 1990 and 2010.

Gas turbine power plants coming on line after the year 2000 will be able to deliver very high thermal efficiency (60 percent based on low heating value) with natural gas in a combined cycle mode. Integrated gasification combined cycle or other advanced coal-fueled plants utilizing gas turbines also will deliver a combined cycle efficiency in the range of 60 percent (LHV). Current state-of-the-art combined cycle thermal efficiencies for gas-fired combustion turbines are in the range of 45 percent to 52 percent (LHV).

Gas turbine combined cycle systems operating on coal-derived gas or natural gas fuels will become competitive with other technologies for meeting peak and base load power demand. High availability (capacity factors) and performance of these fuel-flexible machines have been receiving considerable attention from end users and suppliers.

In some applications, gas-fired turbines are brought on line initially due to low first cost, shorter construction/on-line time, and to meet the peak power needs. Through staged construction, these plants then can be converted later on to accommodate coal-gas as the fuel and operate as base load units. IGCCs and PFBCs are ideal candidates which utilize coal and improve the operating cost of gas turbine/combined cycle systems.

Market forces will determine whether a coal-fired or gas-fired turbine combined system or any other power generation source can remain competitive. Key market drivers which would influence the extent of gas turbine applications are the price of electric energy, environmental legislation, and demand side management to improve end use efficiency.

Technology Description

Gas turbines are among the high efficiency power generation systems. Gas turbines, in their simplest form, consist of a multi-stage compressor to compress ambient air to some specified pressure level; a combustor to burn the fuel and raise the temperature of the compressed gas from the compressor; a multi-stage gas turbine to extract energy from the hot gas stream; and a generator to produce power.

To achieve high efficiency and system economy, and to meet different and specific applications, gas turbines are modified further. The various versions of gas turbines include multi-shaft gas turbines, intercooled and recuperative cycles, humid air turbine cycles, and thermo-chemically recuperated cycles. The high pressure, high temperature features of a gas turbine enable the system to achieve high efficiency.

Coal-based power plants projected for application over the next 20 years will incorporate some of the advanced integrated coal gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC) systems. These advanced coal-fueled plants generally utilize gas turbines and combined cycles for their operation.

Some of the proposed thermodynamic cycle configurations are:

- Advanced Gas Turbine Combined Cycle.
- Intercooled Recuperative (ICR) Cycle.
- Humid Air Turbine (HAT) Cycle.
- Modified Humid Air Turbine Cycle.
- Thermo-chemical Recuperation Cycle.

Cycle analyses indicate that all the cycles identified above will approach the ultra high efficiency goals of IGCC and PFBC.

Specific configurations for each of the above cycles may differ in terms of overall performance optimization. However, basic components making up a system are generally similar. Each advanced gas turbine/combined cycle basically contains a combustion turbine with a high exhaust temperature, coupled to a bottoming cycle. The bottoming cycle will include a heat recovery steam generator and a steam turbine.

An important component which would contribute significantly to the overall efficiency of an advanced gas turbine/combined cycle plant is an improved steam cycle. Current efficiencies of steam cycles are in the range of 35 percent to 40 percent (LHV). The trend is toward higher pressure, higher temperature steam turbines which would yield efficiencies in the range of 40 percent to 45 percent (LHV). Manufacturers of steam turbines in the U.S., Europe, and Japan are developing reheat units which would operate at very high ranges of temperature and pressure and yield steam turbine efficiency around 45 percent (LHV).

The intercooled recuperative (ICR) cycle engine offers significant thermal efficiency improvements over the simple gas turbine cycle. The recuperator raises compressor discharge temperature, and the intercooler reduces the work required to achieve a given compression ratio. The ICR cycle provides high efficiency at low pressure ratios compared to an advanced combined cycle. The ICR exhaust is generally too low in temperature to accommodate a steam bottoming cycle but offers a potential for other working cycles.

A modified humid air turbine (HAT) cycle would increase turbine mass flow and further improve the heat rate and thermal efficiency over the ICR cycle. A HAT cycle, however, would utilize high pressure ratio compressors since the high compressor discharge temperatures would facilitate evaporation of large quantities of water at compressor

discharge. The HAT cycle requires high purity water usage, which is a major drawback of the cycle. Adding the evaporator (with its water system) to compressor discharge of an ICR cycle also would enhance the cycle.

The thermo-chemical recuperation cycle requires gas turbine exhaust temperatures higher than normally required in an advanced combined cycle system. This, in turn, would require higher firing temperature in the gas turbine. The chemical recuperation works on the principle of transferring the low-grade heat in the turbine exhaust to the premium chemical energy in the fuel to increase the overall thermal efficiency. Supplemental firing or recovering the high temperature heat upstream from the power turbine for the reforming reaction is expected to have marginal benefits.

A coupling of fuel cell technology with advanced gas turbines is perceived to offer the highest overall efficiency and cleanest power generation systems. The economics and concepts evaluations need to be improved. Use of fuel cells as a topping cycle or a bottoming cycle to a gas turbine warrants further investigation, especially depending upon the type of fuel cells and fuels being used for the fuel cells.

In order to obtain ultra high thermal efficiency, gas turbine cycles with high pressure ratio and high firing temperatures would be required.

Development Status

The U.S. Department of Energy (DOE) is sponsoring a ten-year, \$750 million advanced turbine systems (ATS) program. The Electric Power Research Institute (EPRI), Gas Research Institute (GRI), and EPA are coordinating with DOE on this program. Major gas turbine manufacturers participated in the study phase of the program. At least four turbine manufacturers are currently under contract to develop conceptual designs and meet the DOE goals of ultra high efficiency and pollution prevention.

The remaining phases of the program are design, development, and demonstration of high efficiency, cost-effective gas turbines for power generation and cogeneration applications after the year 2000. A parallel activity also has been initiated by a group of electric utilities in cooperation with EPRI and GRI. The focus of this activity is to apply aeroderivative turbine technology to industrial turbines. Several manufacturers with aeroderivative experience currently are participating in this program. The objective of this program appears to be to achieve near combined cycle efficiency in a simple cycle gas turbine.

Based on preliminary feasibility studies, at least four different advanced turbine cycles have been proposed by gas turbine manufacturers which would meet the high performance objectives of the DOE program. Three aeroderivative technology application concepts also

are being evaluated in a parallel activity sponsored by the utilities. The DOE-sponsored programs are scoped to move into full-scale demonstration by the year 2000. There is, however, a great need to deliver intermediate improvement in gas turbines. The major potential market for gas turbines in commercial application is expected to peak in a shorter time frame than the present schedules of the two major high efficiency turbine development programs. This issue must be addressed by the program sponsors.

Preliminary cycle studies have been conducted by several gas turbine manufacturers participating in the DOE/ATS program to determine the feasibility and suitability of this concept. The gas turbine manufacturers have proposed different cycles and configurations to meet the goals outlined above. A plethora of configurations is being presented by manufacturers, based on their respective familiarity and technical accomplishment.

Advanced gas turbine combined cycle (AGTCC) systems goals are to meet high efficiency, stringent NO_x emissions requirements (≤ 8 ppm or 0.03 lb/MBtu) and provide low-cost electricity compared to other competing systems. The escalating costs of transmission and distribution force an end user (electric utility or independent power producer) decision to favor smaller distributed generation systems over large centralized power plants.

Integrated High Performance Turbine Engine Technology (IHPTET) initiatives under the leadership of the U.S. Air Force are focused to solve critical technology issues for high temperature, high pressure gas turbines. In cooperation with the aerospace industry, the Air Force has witnessed very encouraging results to date. These accomplishments would enhance the application of this sophisticated technology to high efficiency gas turbine hot sections. Examples of this aeroderivative technology include advanced materials, such as single crystal airfoils and combustion liners, and advanced cooling techniques.

A combination of advanced material and air-cooled component design has resulted in a technology which provides superior capability at temperatures exceeding 2600°F. This capability enables the operation of metallic materials near stoichiometric combustion temperatures. Incorporation of advanced material and cooling technology combinations into a gas turbine hot section design demonstrates far superior cooling effectiveness compared to conventional cooling technology, including the advanced impingement-film cooling technology.

The Oak Ridge National Laboratory (ORNL) currently is conducting studies on the impact of judicious utilization of cooling air at high temperatures and for high cycle efficiencies. ORNL's preliminary data on the effects of intercooling and no intercooling on cycle efficiency for various turbine inlet temperatures show the distinct advantage of intercooling on cycle efficiency improvement and the ability to operate a gas turbine at lower temperature compared to one with no intercooling but the same efficiency.

Simple cycle efficiency decreases as steam cooling of the airfoils is increased, while the overall combined cycle system efficiency may be enhanced. This impact points out that when maximizing the overall combined cycle, the impact of steam cooling also must evaluate the corresponding reduction in the simple cycle efficiency.

Advanced gas turbines form the power generation island base for several CCT demonstration projects, including IGCC, PFBC, and indirect-fired cycles.

Environmental Performance

Gas turbines generally are regarded as clean power sources. In their role as power generation islands, gas turbines meet or exceed all applicable environmental requirements. NO_x emissions usually are very low (about 0.1 lb/MBtu or less). The high efficiency of gas turbines results in low emissions of other "greenhouse" gases.

Commercial Impact

Gas turbines of high efficiency and adaptable to coal gasification or pressurized fluidized bed combustion are available commercially. The advanced gas turbine systems with ultra high efficiency and low emission design also must meet the cost and reliability, availability, and maintainability requirements of current gas turbines.

Preliminary designs of candidate cycle configurations are in the process of being established. As stated earlier, the DOE Advanced Turbine Systems program, for example, has set its goal to achieve a 10 percent reduction in the projected cost of electricity compared to a state-of-the-art system.

End users of power generation systems include both the utilities and independent power producers. Both groups, however, view lowest capital cost as an essential criterion for decision making. Levelized busbar costs are important, but as an additional requirement, not as the only requirement. An optimized complete package by a supplier would be cost-effective and also shorten the overall construction schedule. In a phased construction approach, a gas-fired simple cycle gas turbine is added first, an expansion to combined cycle is made, then conversion to coal-derived fuels would be the final step.

An exciting and innovative opportunity for advanced gas turbines is in distributed generation application. These power modules, some readily transportable, can be installed at sub-stations, thus minimizing the burden of transmission lines and transformer equipment.

In order to achieve the goals for the advanced gas turbine/combined cycle, the capital cost and levelized costs should be below the best coal technology alternative. Furthermore, the

advanced gas turbine must be adaptable to operating on coal-derived fuel. This feature should enhance further the price competitiveness of advanced gas turbine/combined cycles coupled with an IGCC, a PFBC, an IGHAT, or other coal-based systems.

If the advanced gas turbine/combined cycle does achieve its cost goals, it is expected that the cost of electricity from these plants should be less than the best current system.

The U.S. power generation from gas turbines during the next 20 years is expected to be approximately 370 billion kilowatt hours. If 50 percent of gas turbine power plants are assumed to be AGT/CC, then based on levelized costs alone, these power plants could provide a net savings of approximately \$2 billion over the current state-of-the-art power plants.

Development Needs

The important parameters which advanced gas turbine combined cycle systems must meet in the next decade to be competitive with other power generation alternatives are:

- Ultra high thermal efficiency -- ≥ 60 percent (LHV).
- Higher firing temperatures -- $\geq 2600^\circ\text{F}$.
- Low heat rate -- ≤ 7000 Btu/Kwh.
- Dry low NO_x systems -- 10 percent lower (lbs/Kwh).
- Lower cost of electricity (busbar cost) -- 10 percent less.
- Adaptability to coal-derived and biomass fuels -- for example, IGCC, APFBC.

Key technology needs of ultra high efficiency, high firing temperature gas turbine systems are:

- High temperature alloys (metallic materials) development.
- Coating for oxidation and hot corrosion prevention.
- Advanced ceramics for high temperature application.
- Ultra low NO_x , low CO combustion systems, including catalytic combustion.
- High efficiency, high temperature recuperators.

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- High pressure-ratio compressors.
- Advanced cooling techniques for hot sections.
- Low aerodynamic and secondary flow loss components.
- Advanced bottoming cycles (steam turbine, heat recovery steam generator).
- Adaptability to coal-derived, petroleum-based, biomass-derived fuels.
- Alternate working fluids.

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B. Indirect-Fired Cycles

Technology Description

The indirect-fired cycle represents an attractive emerging technology for powering high efficiency combined gas and steam turbine cycles with coal or other fuels. It enables application of combined cycle plants to conventional coal-fired technology. A major objective of the indirect cycles is to achieve significant increases in the thermodynamic efficiency of coal and biomass combustion for electric power generation. This technology is applicable to burning coal, biomass, and wood byproducts. Indirect firing means products of coal combustion do not come in contact with the working components of a gas turbine. Repowering with indirect-fired or externally fired cycles offers utilities a near-term application potential for existing coal-fueled power plants. Coal or other ash-bearing fuel is burned in an atmospheric combustor. Hot combustion gases flow on the shell side of a tube-type metallic or ceramic air heater. On the tube side of the air heater, compressed air from a gas turbine compressor is heated as it passes through the air heater. The heated air enters the turbine section of the gas turbine engine. Exhaust flue gas from the air heater passes through a heat recovery steam generator, where steam is generated to power a steam turbine. Flue gas exiting the steam generator is treated to remove SO₂ and particulates (see Chapter III, Part C). The oxides of nitrogen are controlled during the combustion process through the use of low-NO_x burners in the atmospheric coal combustor.

Development Status

Indirect-fired gas turbine power plants have been investigated since the 1930s, as described by Keller in a paper in 1946. The first closed cycle gas turbine (500 kW) with a peat-fired

metallic air heater was built and operated, leading to the installation of several cogeneration facilities. Experimental studies showed promising results for an open cycle gas turbine based on the Mordell cycle. In this cycle, the heat input to the gas turbine is supplied through a heat exchanger from the solid fuel combustion products. The metallic heat exchangers used in the earlier experiments limited the temperatures at which gas turbines could be operated. This limitation adversely affected economic power production. An approach proposed is the use of ceramic air heaters, which would enable the use of gas turbines at high inlet temperatures.

A ceramic air heater development program is being sponsored by the U.S. Department of Energy. A test facility is being operated utilizing a ceramic heat exchanger coupled to a gas turbine. The air heater is a high pressure, high temperature unit which is designed to operate under turbine operating conditions. A key development issue is the operation of the air heater on gases from an atmospheric combustor, without a build-up of slag or corrosion of the tubes and with minimum leakage of high pressure gas turbine air. Successful operation of a ceramic air heater would enable the achievement of higher efficiency for the indirect-fired combined cycle system.

The Pittsburgh Energy Technology Center also is supporting indirect firing for repowering and new installations of steam electric power plants. The applications include both the metallic and ceramic versions of air heaters which are coupled with gas turbines. A program identified as high performance power systems (HIPPS) is approaching the system development and test phase. DOE has selected an indirect-fired cycle system for a CCT demonstration project. This system will consist of a ceramic air heater and a gas turbine, and it will burn utility grind coal in an atmospheric combustor.

Environmental Performance

The indirect-fired cycles will utilize advanced environmental control systems for coal-fired steam electric plants (see Chapter IV, Part C). These systems appear capable of meeting environmental requirements of repowering systems.

Commercial Impact

The indirect-fired cycles are suitable for repowering applications on a near-term basis. For new applications, however, these cycles may not be competitive.

Development Needs

The following challenges must be met by the indirect-fired cycles to enable the application of these systems for repowering and commercialization:

- Ability to operate air heaters with minimum ash deposition, erosion, and corrosion.
- Ability of the air heater material to withstand high temperatures for operation over long periods of time.
- Development of high temperature flow diverter valve between the air heater and gas turbine.
- High thermal shock resistance capability for ceramic air heaters operating at high temperatures.

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C. Fuel Cells

Technology Description

Fuel cells are emerging, next-generation power conversion systems because of their potential for high energy conversion efficiency. The fuel cell has been called a "continuous battery" since it converts hydrogen and oxygen to direct current (DC) electricity, water, and heat. The fuel cell conversion system consists essentially of four fundamental parts:

1. A fuel processing system to catalytically reform methane, methanol, synthesis gas from coal, or light distillates to a hydrogen-rich gas.

2. A fuel cell stack which converts hydrogen and oxygen (air) to direct current (DC) electricity.
3. A power conditioning system which converts the DC power to alternating current (AC) and transforms the AC power to an appropriate line voltage.
4. A heat recovery system to produce steam and to improve the overall conversion efficiency from fuels to electricity (high temperature systems only).

Since the fuel cell converts chemical energy directly to electrical energy, the conversion efficiency is not affected by Carnot cycle limitations. While the first generation will be fueled by natural gas, future applications can be based on coal-derived fuel (see Chapter V, Part B). Thus, this technology offers an additional opportunity to use coal with high thermal efficiency and good environmental performance. Fuel cells operating at high temperatures (1200°F to 1800°F) can be coupled to a steam bottoming cycle to provide a fuel cell combined cycle power system with conversion efficiencies of 50 percent to 60 percent (LHV).

Fuel cells generally are characterized by the electrolyte used to support ion transport in the cell stack. The three major classes of fuel cells currently being developed use the phosphoric acid (H_3PO_4), the molten carbonate (LiKCO_3), and the solid oxide (ZrO_2 and Y_2O_3) systems. Key characteristics of each of these systems are shown in Table IV-C.

Development Status

Phosphoric Acid Fuel Cells (PAFC)

Phosphoric acid fuel cell (PAFC) systems are the most technically mature of the three classes being developed. These cells operate at about 400°F. They presently are available commercially in sizes from 50 kWe to 200 kWe to as large as 11 MWe.

Approximately one hundred 50 kWe units have been deployed in semi-commercial service, fueled by natural gas. After some initial problems, stack performance is now very reliable. Estimated stack lifetimes are 5 to 7 years (40,000 to 60,000 hours).

The first large-scale fuel cell (4.5 MWe) went on line at the Tokyo Electric Power Company (TEPCO) Goi Station in 1983 and operated through 1985. Currently, the largest fuel cell is an 11 MWe PSFC at TEPCO's Goi Station. It is composed of eighteen 700 kWe stacks connected in a series-parallel network. Each stack produces 350 volts at a 200 ampere current (DC), and the power to the inverter is about 2.1 kV at 6000 amps. This plant was constructed by Toshiba Corporation with fuel cell stacks manufactured by a U.S. company, International Fuel Cells Corporation (IFC). Power generation began in 1991.

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TABLE IV-C
FUEL CELL TYPES AND CHARACTERISTICS

Electrolyte	Phosphoric Acid	Molten Carbonate	Solid Oxide
Operating Temperature	400 F 200 C	1200 F 650 C	1800 F 1000 C
Operating Pressure (atm)	1 to 10	1 to 10	1 to 10
Module Size near-term advanced	200 kW 11 MW 25-50 MW	1-2 MW 100-400 MW	100 kW 2 MW 20-300 MW
Construction Materials	Carbon Based	Nickel and Stainless Steel	Ceramics
System Eff. % HHV Btu/kWh	40-45 % 8300-7000	50-57 % 6800-6000	45-50 % 7600-6800
Utility Applications	Intermediate	Base Load	Base Load
Long Term (fuel type)	Distributed Generators (natural gas)	Central Station (gas, coal gas)	Distributed Generation (gas, coal gas)
Largest Module	11 MW	120 kW	25 kW
Key Issues for Commercialization	Competitive Reliability Stack Life Operation and Maintenance	Scale-up Manufacturing Cost Durability Reliability Stack Life	Scale-up Manufacturing Cost Durability Reliability Stack Life
Timing	1997	1997-2000	~ 2000

These early systems have conversion efficiencies of approximately 40 percent. Toshiba has announced plans to produce about twenty 11 MWe units per year, with declining capital costs, higher efficiencies (45 percent), and smaller plant footprint. These activities in Japan have been enhanced by tax incentives offered by the Japanese government.

Molten Carbonate Fuel Cells (MCFC)

Molten carbonate fuel cells (MCFC) operate at high temperature (1200°F) and are now emerging from laboratory-scale testing to 100 kWe pilot plants. Since the MCFC operates at temperatures of approximately 1200°F, the fuel can be coal-derived synthesis gas or methane can be reformed to hydrogen internal to the cell. (Catalytic reforming is performed by flowing steam and methane through a porous nickel bed on the anode side of the fuel cell.) Theoretically, the MCFC cell should be the most efficient of the three competing systems and should have an even greater relative advantage when the overall system efficiency (including the steam bottoming cycle) is considered. System conversion efficiencies of 50 percent to 57 percent are projected for MCFC powerplants.

Unconverted fuel in the anode exhaust is combusted in an external burner to produce carbon dioxide, which is fed with air to the cathode to replenish the carbonate ions in the cell. Excess air in the cathode feed provides not only oxygen for the electrochemical reaction, but also the required cooling of the cell stack assembly. The system operates at essentially atmospheric pressure, although cell voltage improves with increasing system pressure.

The first full-scale 2MWe demonstration plant is planned for initial operation in 1995. This facility will be sited on the city of Santa Clara, California, system and is supported by a consortium of utilities, the Department of Energy, and the Electric Power Research Institute.

The design of the 2 MWe demonstration unit is based on four skids of molten carbonate fuel cell stacks. Each skid contains four fuel cell stacks. Each fuel cell stack is composed of approximately 250 cells with a nominal area of six square feet and produces about 195 volts and 630 amperes. A typical configuration will have each skid wired in series to produce about 780 volts and 630 amperes.

Although stack lives of five years (40,000 hours) are projected, the longest test runs to date have been only 10,000 hours with 100 kWe stacks. Future commercial systems are envisioned both as dispersed stand-alone units fueled with methane, methanol, or other clean fuel and as central-station units integrated with coal gasification facilities.

Solid Oxide Fuel Cells (SOFC)

The very high temperature (1800°F) solid oxide fuel cells (SOFC) are solid-state, ceramic devices with attractive electrochemical conversion efficiencies. This technology is based on an electrolyte made of a solid phase solution of stabilized yttrium oxide (Y₂O₃) in zirconium oxide (ZrO₂). This approach is projected to reduce corrosion and minimize electrolyte management issues associated with MCFC systems.

The cell performance of an SOFC is not as high as that of an MCFC system and typically has a cell voltage which is only 75 percent as high as the MCFC voltage. The higher operating temperature of the SOFC does provide a substantially improved bottoming cycle efficiency (subject to Carnot cycle limitations). Overall system efficiencies of 45 percent to 50 percent are projected.

SOFCs are expected to be very light in weight and compact in size, offering the potential for more flexibility in siting. The technology is the least developed of the three alternatives. Tests have been conducted with 25 kWe stacks, and a 100 kWe plant recently has been completed. Development challenges center on thermal stresses in the high temperature environment.

Environmental Performance

Fuel cells have two important characteristics: high conversion efficiency and low general emissions. This is particularly the case in terms of NO_x emissions at the point of use. Fuel cells typically produce 5 ppm of NO_x at 15 percent excess oxygen.

Sulfur dioxide emissions are extremely low as the steam reforming catalyst cannot tolerate any significant concentrations of sulfur in the fuel stream. Since clean fuels, including synthesis gas, are utilized, particulate emissions also are very low.

In integrated coal gasification fuel cell powerplants, the synthesis gas can be steam shifted essentially to an all hydrogen feed to the fuel cell. The carbon dioxide can be extracted from the shifted synthesis gas.

The primary route for achieving low carbon dioxide emissions, however, is achieving high conversion efficiencies. Both the molten carbonate and solid oxide fuel cells integrated with steam bottoming cycles show promise of achieving coal to electricity conversion efficiencies of 50 percent to 55 percent when coupled to advanced coal gasification processes. This results in an estimated carbon dioxide emission rate of approximately 0.7 tons per megawatt-hour. These systems must be in the 200 MWe to 500 MWe capacity range when integrated with coal gasification processes.

Commercial Impact

Phosphoric acid fuel cell powerplants fueled by natural gas are available commercially in the 50 kWe to 200 kWe capacity range. One 11 MWe powerplant is operating in Japan. However, U.S. utilities have shown little interest in the system due to first cost and durability concerns. Japan has plans to deploy numerous commercial systems at the multi-megawatt scale.

A 2 MWe molten carbonate fuel cell is scheduled to begin operation in Santa Clara, California, in 1995, using natural gas as fuel. Long duration performance testing will determine the commercial readiness of the technology. Commercial units in this size range should be available commercially by about the year 2000. Over the long term, the market for MCFCs should be good as they are integrated with coal gasifiers.

Commercial projections for SOFCs are premature. Units with hundreds of kWe capacity are just entering operation, and durability testing is critical. If lower temperature (1300°F) systems can be developed successfully, the long-term (beyond the year 2010) prospects for commercialization appear to be good.

Development Needs

The three primary issues associated with fuel cell applications are (1) manufacturing cost, (2) stack lifetime and durability, and (3) system complexity and reliability. These all have been addressed for the phosphoric acid fuel cell, but there still are numerous fundamental improvements necessary to effect commercialization of either molten carbonate or solid oxide cells.

Some of the remaining key research and development issues associated with molten carbonate fuel cells (MCFC) are:

- Long-lifetime internal reforming catalysts and minimization of anode creep.
- Cathode stability and lifetime and material improvements, particularly substitutes for nickel oxide.
- Electrolyte inventory management problems, particularly cell.
- Minimizing internal reforming catalyst contamination.
- Development of cost-effective manufacturing processes.
- Stack design accommodating pressure requirements for electrical contact, cell-edge resilience, sealing, and creep considerations.

The solid oxide fuel cells (SOFC) presently are composed of thin layers of ceramic materials, an yttria-stabilized zirconia solid electrolyte, and a lanthanum manganite cathode. They operate at approximately 1800°F. An operating temperature near 1300°F would improve SOFC performance, reduce interdiffusion problems and fabrication costs, and make it possible to use less expensive metal electrodes.

Key research efforts necessary to achieve lower temperature SOFC systems or successfully complete development include:

- Creating very thin layer solid electrolytes to minimize resistance losses.
- Enhancing chemical stability of low temperature ion conductors such as bismuth-zirconia.
- Synthesizing new classes of electrolyte materials.
- Developing metal containing cathodes compatible with 700°C operation.
- Developing acceptable cathode support materials for operation at 1000°C.
- Developing proton conductor SOFC electrolytes.
- Developing multilayer cells with compatible thermal expansion characteristics.

Continued research and development on both MCFC and SOFC are strongly recommended as these power conversion systems, coupled to coal gasification processes, promise very high efficiencies and clean power from coal. Continued integrated testing of fuel cells with coal-derived synthesis gas should be emphasized.

D. Magnetohydrodynamics

Technology Description

Magnetohydrodynamics (MHD) is a direct plasma energy conversion technology for electrical power generation. MHD can be achieved by burning any coal in a pressurized combustor with preheated air or oxygen to produce a combustion gas having a temperature between 4700°F and 5000°F. A seed material, such as a potassium salt, is added to increase electrical conductivity. The combustion gas and vaporized/ionized seed are passed through an MHD channel within the center bore of a superconducting magnet. This interaction produces direct current electrical power in accordance with the Faraday principle. The remaining heat is used to make steam to drive a conventional turbine generator.

Development Status

The MHD development effort in the 1960s and 1970s was focused on developing and testing individual MHD components at several small laboratory-size test facilities. In the early 1980s, DOE began developing and testing MHD components at two test facilities that

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were constructed in the late 1970s. These facilities are owned by DOE, operated by private contractors, and contain some equipment built with private (non-Federal) funds. The 50 MWt Component Development Integration Facility (CDIF) is located in Butte, Montana, and the 28 MWt Coal-Fired Flow Test Facility (CFFF) is located in Tullahoma, Tennessee.

In 1984, DOE held public meetings to discuss the direction of MHD research and development and to formulate a more focused approach to its MHD program. The MHD Proof-of-Concept (POC) program was established as a result of a consensus between government and industry representatives participating in these meetings. DOE formulated its detailed POC plans and objectives during the next 3 years and awarded the first contracts under the POC program in September 1987. The POC program has been managed by DOE's Pittsburgh Energy Technology Center (PETC). Annual Program Plans describing progress and reflecting specific funding plans have been published.

The main objectives of the POC program were to test and demonstrate (1) the integrated topping cycle system at the CDIF, (2) the integrated bottoming cycle system at the CFFF, and (3) the potassium seed regeneration system at a pilot facility in California. The regeneration intent is economically to convert the spent potassium seed recovered from the bottoming cycle to a sulfur-free potassium compound that can be reused in the combustor. In addition, the POC program was to study the feasibility of retrofitting MHD power systems to existing coal-fired plants. The retrofit studies were done by separate teams of contractors on commercial power plants in Florida and Montana.

The POC program was concluded officially on September 30, 1993. Not all of the planned topping and bottoming cycle tests were completed, but budget decisions required the conclusion of the program at that time.

Achievements to date indicate that the engineering data base is sufficient to allow the design of a 100 MWe integrated cogeneration MHD plant. Two industrial and utility teams produced separate designs under DOE's POC Integrated Demonstration Program. One team expanded that work and submitted a proposal to DOE as part of the Clean Coal Technology V solicitation to build an integrated MHD demonstration plant. Although it was not successful, it was nonetheless a significant landmark for MHD.

In addition to the achievements of the U.S. MHD development, significant developments have been made in foreign countries, including Russia, China, India, Japan, the Netherlands, Italy, and Australia. With the large supply and dependence on coal in China, a significant current program is the design and initiation of construction of a 12 MWt, totally integrated coal-fired test facility in Peking. DOE has signed a cooperative agreement with China and has contributed a Superconducting Magnet to the project.

Environmental Performance

Among the main driving forces behind the interest in the development of coal-fired MHD are its environmental performance and its potential to provide responsible economical solutions to global environmental concerns.

An MHD cogeneration cycle achieves large efficiency increases since the electrical power produced from the MHD generator (topping cycle) is additive to the power produced from the steam turbines (bottoming cycle). Sulfur emissions are reduced when the seed material combines with the sulfur oxides to form a solid. Nitrogen oxide emissions can be controlled below today's standards, and particulate emissions are reduced using conventional baghouse or electrostatic precipitator technologies. MHD plants also would reduce carbon dioxide because of the higher efficiency.

Most MHD development has been for coal-fired electrical power generation. Environmental performance has been a very important part of that development and one of the key objectives of the >3600 hrs of testing at the CFFF. During these tests, high-sulfur Eastern coal was utilized for ~2600 hrs; the remainder was on lower-sulfur Western coal. Many of the tests were performed with a coal-oil mixture. The data from these tests provide a consistent relationship between the amount of SO₂ removed and the amount of seed material (K₂CO₃) added. The results show that when the optimum amount of seed for MHD conductivity is added, more than 95 percent of the SO₂ is removed; more than 98 percent SO₂ removal was demonstrated consistently. With Western coals, >99.5 percent was attained.

The production and subsequent reduction of the oxides of nitrogen have been demonstrated. Fuel-rich combustion and rapid cooling rates reduced NO_x to levels as low as 0.085 lb/MBtu for Eastern coal. The amount of CO₂ is reduced proportionately with the increased efficiency of the total process.

In addition to the demonstrated environmental performance described above, the efficiency potential of coal-fired MHD operation has major additional positive environmental consequences. System studies have shown that the ultimate potential efficiency for a coal-fired MHD system is greater than 60 percent. To attain this high efficiency will require advanced materials, an ultra-super-critical steam cycle, and electrical stress within the channel increased well beyond the current state of technology.

Commercial Impact

An approach to MHD commercialization was published as "The Commercialization of Magnetohydrodynamics Electric Power Plants" by R. Weinstein/W. Owen and presented July 1, 1993, at the 31st Symposium of Engineering Aspects of MHD (SEAM). This

paper, which is included by reference in this report, estimates that after the first integrated demonstration of the technology at a near-commercial scale, the design basis will be established for a subsequent larger commercial-sized power plant which could be replicated and competitive economically with other power plants utilizing advanced technology. The operating efficiency of this generation of MHD plants will be nominally 44 percent. It is projected that with additional developments in the next ten years, higher efficiency (>50 percent) will be attainable, allowing for full commercial market penetration resulting from this performance.

Development Needs

Requirements for coal-fired MHD technology research and development can be divided into two general areas.

1. To complete the engineering data base required for the development of the integrated demonstration within acceptable risk, the following issues should be addressed before proceeding to the next step, integrated demonstration plant project:

- Topping cycle durability.
- Combustor secondary zone oxidant effects.
- Topping cycle operation on Eastern coal.
- Topping cycle operation with high temperature coolant.
- Channel packaging/magnet bore utilization.
- Use of potassium formate seed.
- Regeneration of spent seed from Western coal firing.
- Integrated seed regeneration plant operation.
- Seed regeneration plant durability.
- Trace impurity control.
- Integrated MHD system operation and control.

2. To bring MHD technology to its full potential, further research and development must be accomplished in such general areas as the following:

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- High temperature air heaters/heat exchangers -- materials.
- Advancements in superconducting magnets.
- Seed regeneration economics.
- High performance channel/topping cycle/ceramics.
- Advanced steam cycle development.

Effort and advancement in these areas can be parallel with the activities (noted above) necessary to support the first integrated demonstration. In some cases advancements are being made by other technology research and development programs (for example, high temperature materials development, recuperators, and the LEBS program).

It would be advantageous to maintain the capability to further the engineering data base of MHD by maintaining the existing facilities in an operable mode until industry and the government can come to agreement on the future development of MHD. It is therefore recommended that the CDIF and CFFF facilities be maintained, in a mode capable of supporting renewed MHD operation within a 6-month period, for the next three years (FY 1995-1998).

DOE should continue its participation in the Chinese and other foreign coal-fired MHD programs and keep abreast of their developments.

References (Part D)

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E. Coal-Fired Diesel Engines

Since 1982, under the sponsorship of the DOE Morgantown Energy Technology Center, a number of research institutes, universities, and diesel engine manufacturers have conducted research and development that has led to the current technology of the coal-fired diesel engine. There are two key programs in this technology category:

- Coal diesel combined cycle, utilizing large bore, medium speed, Cooper-Bessemer engines for modular, high efficiency, low emissions electrical power generation and cogeneration.
- Coal diesel locomotive, utilizing higher speed, General Electric engines for railroad application.

Coal Diesel Combined Cycle

Technology Description

The coal diesel combined cycle (CDCC) plant is an innovative, modular, clean coal technology developed under the auspices of the DOE. The 10 MW-100 MW capacity range for this technology is targeted at the non-utility generation market: As such, the Clean Coal Diesel fills a critical gap in the portfolio of existing Clean Coal Technologies since, below 100 MW, there are a limited number of competitive coal-to-busbar power plant technologies.

The performance targets of the mature commercial embodiment of the Clean Coal Diesel are 48 percent efficiency (6,830 Btu/kWh heat rate) based on LHV, low installed cost, and an emissions level controlled to 50 percent-70 percent below current New Source Performance Standards (see Environmental Performance).

The CDCC plant incorporates Cooper-Bessemer LSVC-family engines integrated with a rankine bottoming cycle. The advanced technologies developed to power these engines with coal include cost-effective coal preparation to provide an "engine-grade" coal water fuel (CWF), durable engine components, and an emission control system. A description of these components is summarized below:

- *Coal water fuel:* The prime movers are fueled with "engine-grade" coal water fuel which has been physically cleaned to an ash level of approximately 2 percent (dry basis) and has a mean particle size of approximately 12 micron. The coal particles are suspended in water, and the resulting CWF is typically 48 percent solids. Through the use of additives, the CWF can be pumped and injected much like the heavy fuel oils used in slow speed diesel applications. The typical ash content is about 2.0 percent. While cleaning the coal to remove the ash, the sulfur also gets removed, and the typical sulfur level is about 0.6 percent.
- *Durable engine components:* Coal water fuel is injected directly into the engine's combustion chambers through fuel injectors which were designed and developed to be compatible with the fuel. Each injector is fitted with a 19-orifice nozzle utilizing sapphire inserts for each orifice. The combustion chambers are fitted with twin diesel pilot injectors which provide a positive ignition source and substantially shorten the ignition delay period of the CWF fuel. Durable coatings (typically tungsten carbide) are used for the piston rings, cylinder liners, and turbocharger blades to reduce wear rates associated with the abrasive fuel.

Development Status

The coal-fired engine technology has been demonstrated successfully on a 2,600 horse power, commercial production-size engine, complete with full size emissions control equipment. The engine developed full power output at rated speed and does not require derating for CWF operation.

Over 1,000 hours of engine operating experience on CWF was gained, and another 1,000 hours of engine operation is planned before two 6,300 kW CWF engines are built for field testing.

Initial efficiency of 6,500 Btu/bhp.hr-7,000 Btu/bhp.hr (LHV) is acceptable, and further optimization is possible. The combustion chamber remained clean after CWF operation, and there were no visible emissions from the stack after emissions control system. The power plant emissions were 50 percent-70 percent lower than NSPS standards.

Test results, therefore, show that the technology met both the efficiency target and the emissions target, and performance in these areas did not degrade during the 100-hour

proof-of-concept test. Efficiency and emissions improvements seem achievable through engineering scale-up of the engine and emissions control system to commercial plant sizes.

Longer run times are needed to estimate useful lifetimes of certain engine components, particularly the useful life of piston rings and exhaust valves. These data on engine components are critical before commercial introduction of the technology. Engineering solutions and material selections are available for durable components, but these solutions must be optimized and demonstrated for several thousand hours, not several hundred hours as has been accomplished so far.

Environmental Performance

Effective controls for NO_x, SO_x, and particulate emissions are essential for successful commercialization of stationary, coal-fueled diesel engines. The DOE/METC-sponsored program has established the optimum emissions control system from both performance and cost perspectives.

The targets for NO_x, SO_x, and particulate matter emissions represent approximately a 50 percent-70 percent reduction below the existing New Source Performance Standards for coal-fueled power plants. These levels will be attained through a unique combination of fuel and combustion modifications and exhaust gas clean-up. The emissions control system for the Clean Coal Diesel is a low-risk emissions control design, assembled from off-the-shelf exhaust gas treatment subsystems.

The integrated coal-fueled diesel Emissions Control System (ECS) is comprised of in-cylinder NO_x reduction, cyclone, Selective Catalytic Reduction (SCR) reactor, sorbent injection, baghouse, induced draft (ID) fan, and flue gas sample conditioning and analysis.

In operation, exhaust gas from the engine first enters a cyclone, where relatively large particulate matter is removed. Gas exiting the cyclone goes to the engine's turbocharger, where the temperature and pressure are reduced to about 850°F and 20 in. water gauge, respectively.

The first subsystem in the ECS is the SCR reactor, where NO_x is reduced by about 85 percent. NO_x levels of 0.18 lb/MBtu were achieved, compared to an NSPS limit of 0.6 lb/MBtu. The various factors/systems that contribute to NO_x reduction are water injection (contained in the CWF), combustion optimization, selective catalytic reduction, and dry sorbent injection.

Then exhaust gas enters the heat recovery steam generator (HRSG), which reduces the gas temperature from about 850°F to 350°F. After the HRSG, exhaust gas from the engine passes through a mixing venturi, where the sorbent is injected into the gas, reducing SO₂

by about 80 percent. The SO_x emissions are 0.37 lb/MBtu, compared to an NSPS standard of 1.2 lb/MBtu and 90 percent reduction. This is equivalent to emissions from a 0.3 percent sulfur diesel-fuel engine.

The exhaust gas and sorbent mixture enters the baghouse, where the sorbent is removed from the exhaust gas. The particulate emissions are 0.01 lb/MBtu, compared to an NSPS standard of 0.03 lb/MBtu. After the baghouse, the clean exhaust gas flows through the ID fan and to the stack.

Over the course of the 100-hour coal-fired engine demonstration test, 85 percent NO_x reduction, 77 percent SO₂ reduction, and 99.9 percent particulate reduction were achieved.

Commercial Impact

The program recently initiated by Cooper-Bessemer/Arthur D. Little is a field demonstration program that will provide 5,000-10,000 hours of engine operation on coal fuel. Since this will require four years of testing, the implication is that commercial introduction (plant orders) can be targeted in the 2000-2005 time frame, assuming a successful field demonstration.

Coal water fuel is expected to become competitive in the U.S. with diesel oil and natural gas in the 2000-2005 time frame, based on energy price projections made by DOE and others. This would enable CDCC optimization and demonstration of the wear solutions for critical hard parts, through a field demonstration program of 5,000-10,000 hours.

Field demonstration opportunities for small coal-diesel plants will be pursued in special situations where clean coal fuel holds a price advantage, such as:

- Rural electrification (where diesel oil costs \$4-\$12 per million Btu, delivered to certain remote communities).
- Areas which have both coal reserves and the need for rapid installation of non-grid power (such as diesels).
- Eastern Europe, which also has coal reserves and is undergoing rebuilding of the electric power infrastructure in a manner to greatly reduce emissions.

Test experience has shown that the capital cost of the coal diesel plant will not be a problem. The cost of all equipment modules for the plant has been established, and the installed plant cost estimates appear to be competitive at \$1,600/kW for early demonstration plants. This cost will be significantly lower for mature plants. These costs appear to be below the capital cost of other small coal plants.

Test results established the coal-water fuel specification and proved that a wide range of coals can be utilized to prepare engine-grade slurry. The cost of the fuel will be under \$3.00/MBtu if adequate fuel demand exists in a given region. A series of steps must be incorporated to build up an "infrastructure" for coal-water slurry production and distribution.

The commercialization strategy for coal diesel includes:

- Dual-fuel, natural-gas/coal and fuel-oil/coal engines as the entry technology.
- Regional concentration of engines to operate the full-scale coal water fuel plant.
- The new engine's high efficiency (44 percent-48 percent) to minimize greenhouse gas emissions and to lower the cost of electricity.
- The engine's low emissions.
- Support of the initial coal diesel installations with intensive field engineering.
- Developing the infrastructure for low-cost clean CWF processing capacity (\$3/MBtu, delivered).
- Exploiting opportunities to export coal diesel engines to Europe, the Far East, and other areas where natural gas prices are expected to rise sooner than in the U.S.

Development Needs

Cooper has over 1,000 hours of operating experience with CWF. However, the technology is still very young, and there is a definite need for further development. These needs are identified below.

Every effort should be made to lower the cost of CWF. The current concept of producing engine-grade coal for preparing CWF as a byproduct of boiler-grade fuel is one step toward a cost-effective preparation strategy. In this method there will be no waste product that would result, as any coal that does not comply with engine-grade requirements would be used as a boiler fuel. Additives to the CWF and fine coal grinding are significant costs in the preparation of CWF. More R&D effort could be spent on finding alternatives to ball mills that would consume less power, and on developing operational guidelines that can reduce the requirement for fuel additives.

In the injection area, two distinct systems emerged. One was a conventional mechanical system and another the electronic injector. With both, there is a strong need to develop

nozzle tips that provide long, trouble-free life at moderate cost. These designs need to be tested for longer periods and further improvements made.

In addition to the durability of the injection system, the life of other engine components needs to be further improved. Coating processes with lower cost need to be developed for application to exhaust valves in an engine. Also, additional effort is required to improve the life of turbochargers, which are a critical component of a modern engine.

Downstream from the engine is the exhaust gas treatment/emissions control equipment. The long-term effect of particulate/other contaminants on the catalyst system to reduce NO_x needs to be studied. Cyclone performance needs improvement to increase the life of the turbocharger.

Extensive publicity for this technology should be achieved both domestically and internationally. A 14MW coal-diesel power plant is going to be designed and built at Easton Utilities, Easton, Maryland, as part of the DOE Clean Coal Technology V program. The results of this Easton project should be publicized to the power generation community on a global basis as they become available. New opportunities should be identified to build Coal-Diesel power plants:

- Within easy shipping distance of CWF from the first commercial plant to be built at Sugar creek, Ohio.
- In remote areas in the U.S. where oil/gas prices are high and coal is available, such as Alaska.
- Internationally, again, where oil/gas prices are high and coal is plentiful.

To offset the slow acceptance of this new technology, incentives similar to those provided for the Clean Coal Technology V should be made available for the first few Coal-Diesel plants in the U.S. and overseas.

Coal Diesel Locomotive

The coal-fired locomotive requires modifications to the engine (durable components); the fuel system (to store, pump, and inject the coal-water fuel); and the emissions control system. Among the major development efforts for the locomotive program are the development of specialized fuel injection equipment for CWF, diamond compact inserts for the nozzle tips, and an integrated emissions control system consisting of a barrier filter, injection of sulfur sorbent upstream of the filter (copper oxide coated on alumina), and ammonia injection for NO_x reduction over the sulfated sorbent.

General Electric has demonstrated coal-fired locomotive technology in a multicylinder engine operated on a test track at the GE facility in Erie, Pennsylvania. At the time of this writing, GE is not actively pursuing commercialization of the technology because of the current low oil prices. However, GE has developed the critical technologies for the coal-fired locomotive, which are ready for packaging into a commercial system when the market environment becomes favorable to the use of coal for railroad transportation.

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CHAPTER V

COAL CONVERSION

A. Production of Synthesis Gas

Technology Description

Synthesis gas is produced by gasifying coal. Coal gasification produces a mixture of low molecular weight gases, including large amounts of hydrogen and carbon monoxide (and/or carbon dioxide). By the proper choice of process and operating conditions, the amount of hydrocarbon gases can be minimized. The ratio of H₂ to CO in raw syngas from coal can vary from about 2 to less than 0.5, depending on the gasification process. This ratio can be adjusted using the water gas shift reaction. Carbon dioxide and other impurity gases such as hydrogen sulfide and ammonia can be removed using conventional technology. The resulting mixture of hydrogen and carbon monoxide is commonly called synthesis gas (syngas) and can be used to manufacture a wide variety of chemicals and fuels.

Coal gasification involves the conversion of coal into medium-Btu (120 Btu/scf to 300 Btu/scf) or low-Btu (80 Btu/scf to 120 Btu/scf) gas, which can be treated conventionally to produce clean syngas for use in combined cycle power generation. Medium-Btu syngas, which is typically produced by partial oxidation of coal with oxygen, also can be used for chemical synthesis. The conversion step involves reaction of carbon with steam, air, and/or oxygen at elevated temperature and pressure, followed by appropriate treatment and processing steps. Several gasification systems are available, depending on coal type and process requirements, and a variety of advanced power generation concepts include gasification to maximize process efficiency.

Types of Gasifiers

Most gasification processes can be categorized as one of three basic types: moving bed, fluidized bed, or entrained flow. The types differ in gasifier configuration, operating conditions, and upstream and downstream processing requirements.

In the moving bed gasifier, sized coal is fed to the top of the gasifier. At the bottom, oxygen and steam enter, and the ash or slag is withdrawn. As coal moves down through the bed, counter-currently to the rising syngas, it proceeds through four zones: drying, devolatilization, gasification, and combustion. Drying occurs when the hot (800°F to 1000°F) gas exiting the top of the gasifier flows over the incoming coal. Next, the coal devolatilizes, forming phenols, tars, and oils. These compounds exit with the gases and

must be captured and processed in downstream systems. The devolatilized coal then enters the higher temperature gasification zone, where it reacts with steam and carbon dioxide. Both reactions are endothermic, so the gases cool quickly. Near the bottom of the gasifier, the remaining coal consists primarily of char and ash which react with the oxygen (or air). Excess steam is injected to control the temperature at the bottom of the bed. In some processes, called dry bottom processes, the ash is kept from slagging by high rates of steam injection. This increases the amount of water in the syngas and increases the size and complexity of the fuel gas treating systems. In slagging processes, less steam is used, allowing the ash to melt. The slag is then removed and quenched (solidified) with water.

In a fluidized bed gasifier, coal within the unit is kept in a highly agitated, fluidized state by gases flowing at a high velocity up through the vessel. Temperatures within the bed of particles stay within a fairly narrow range, with a very close approach between temperatures of the solids and gases. The exiting syngas temperature is typically between 1600°F and 1800°F. Fluidized bed gasifiers produce fewer tars and oils than moving bed processes (or no such tars and oils) because at 1600°F these compounds pyrolyze to form lighter compounds. Carbon conversion tends to be relatively low due to the lower operating temperatures, short gas residence times, and fine carbon particle carryover. Some processes improve conversion by recovering and recycling unconverted carbon in the fines carryover and by operating the bottom of the gasifier in an ash agglomerating regime. The temperature is elevated enough to cause the ash to become slightly sticky, causing it to clump together (agglomerate) and drop to the bottom of the bed for removal. In this fashion, carryover of unburned carbon fines can be minimized.

In entrained flow gasifiers, finely ground coal, steam, and oxidant are injected together and react very quickly. Most of the ash is carried out (entrained) with the syngas. High gasifier temperatures, typically 2000°F to 2800°F, cause the ash to slag. These conditions promote high carbon conversion with little or no hydrocarbon formation. The high outlet temperature also means that the high level energy in the syngas must be efficiently recovered to maintain overall plant efficiency. Thus, entrained flow gasifiers require larger heat recovery systems than the other types of processes to obtain high conversion efficiency.

Development Status

There are about 30 commercial or demonstration gasification projects in operation and under development worldwide. Most of the existing operating units are used for production of fuels and chemicals. Currently, gasification technology use is focused on coal gasification combined cycle (CGCC) power generation. Further gasification technology development and evolution, coupled with expected improvement in power generation technologies (combined cycle, fuel cell, etc.) and continued cost reduction for support systems (coal handling, oxygen supply, control systems, etc.), should make

gasification-based power generation systems very attractive. This application, combined with coproduction of valuable chemicals or fuels, or cogeneration of steam for industrial use, should further enhance the spread of coal gasification-based technologies.

B. Conversion of Synthesis Gas

Synthesis gas from coal can be processed to produce hydrogen, synthetic natural gas, methanol, and other chemicals. In performing these conversions, there is an inherent energy loss associated with the processes. This results in higher CO₂ emissions than would come from direct utilization of the synthesis gas. In addition, all of these conversion processes require active catalysts, many of them precious metals which must be recovered and recycled or handled as solid wastes.

Hydrogen

Technology Description

One major use for synthesis gas is the manufacture of hydrogen. Hydrogen today is used primarily to manufacture ammonia for fertilizer and to upgrade heavy or sulfur-laden fractions of crude oil. If transportation fuels are made from coal or other solid resources, large quantities of hydrogen will be required. For example, the amount of hydrogen in coal will have to be doubled during manufacture of liquid fuels.

The water gas shift reaction is used to convert the CO to CO₂ and H₂O to hydrogen. Thermodynamics favor a low temperature, but kinetics require temperatures between 600°F and 1300°F. The best catalysts are sensitive to poisoning by sulfur-containing acid gases, so these must be removed. Hydrogen is separated by cryogenic distillation, pressure swing adsorption, or membranes.

Development Status

Hydrogen manufactured from synthesis gas is in wide commercial use. There is continuing research on the development of catalysts that better resist acid gases and on improving hydrogen separation technology using diffusion through selective membranes.

A major issue in the widespread use of hydrogen as a fuel will be development of convenient methods for storing it and for delivering it to the consumer in a safe and low-cost manner.

Low-cost hydrogen was identified by DOE as a high priority research objective in 1988. Results were disappointing, however, because no viable new technology was developed.

Environmental Performance

Hydrogen is the ultimate clean fuel. However, if it is manufactured from coal, all of the carbon in the coal will be converted into CO₂ in the conversion process. The amount of CO₂ emitted per unit of hydrogen will be a function of the process thermal efficiency. Maximum efficiency will require integration of the coal gasification and hydrogen manufacturing operations.

Commercial Impact

If low-cost hydrogen from coal were available, its impact would be enormous. It could become the dominant fuel in almost all types of applications. Major technical improvements are needed to make hydrogen from coal attractive on a broad scale.

Development Needs

Projects to lower costs for making hydrogen from synthesis gas would include efforts to improve catalysts and to seek better technology for hydrogen separation.

Synthetic Natural Gas

Technology Description

For applications other than hydrogen manufacture, catalyst selection and hydrogen to carbon monoxide ratio are used to tailor the product slate from syngas. For example, using a 3/1 mole ratio of H₂ to CO and a nickel catalyst will give virtually 100 percent conversion to methane. This technology is being used to make pipeline-quality synthetic natural gas (SNG) at the Great Plains plant in North Dakota today. Lurgi gasifiers are used to produce the syngas in commercial SNG plants at Great Plains and in South Africa; these gasifiers produce H₂/CO of 2.0 and also make significant methane directly. Cold gas cleanup removes sulfur to less than 1 ppm. Both plants use low rank coals.

Development Status

Most current research on conversion of syngas to SNG involves developing improved catalysts and improving reactor temperature control. Catalysts are sought that are less prone to coking, that are more resistant to sulfur poisoning, and that allow both the water gas shift and methanation reactions to proceed at the same time.

Environmental Performance

Methane is a clean burning fuel with a wide variety of uses.

Commercial Impact

At today's prices, it is unlikely that large volumes of synthetic natural gas will be manufactured from coal. If natural gas supplies are depleted, this technology can be used to supplement or replace available supplies.

Development Needs

No research on SNG is currently budgeted by DOE, and there seems to be little justification for initiating any.

Methanol

Technology Description

Methanol can be used as a feedstock for the production of gasoline, olefins, and diesel fuel. The production of methanol from syngas is a commercial process. Copper-based catalysts (usually Cu-ZnO-Al₂O₃) will convert synthesis gas with a 2/1 hydrogen to carbon monoxide mole ratio virtually 100 percent to methanol. However, the process required is not straightforward. While yields are very high, conversion per pass is limited to about 25 percent by thermodynamics, and even that level of conversion requires low temperature (<480°F) and/or high pressure (60 to 100 atmospheres). Separation of methanol and recycle of unreacted products makes the process expensive.

The current commercial processes use fixed catalyst bed reactors, and there are a variety of designs. The key problem is to remove the enormous heat of reaction and keep the temperature down to promote methanol formation. Normally this is accomplished by packing the catalyst into tubes immersed in boiling water or by the use of conventional, sequential packed beds of catalyst with interstage quenching.

A more recent solution to the heat removal problem is to suspend the catalyst as a slurry in an inert liquid such as mineral oil. This technology, called liquid phase methanol (LPMEOH), was tested in a pilot plant in LaPorte, Texas, for over 7,000 hours under DOE and EPRI sponsorship. The process can carry out both the water gas shift reaction and the methanol synthesis reaction simultaneously, and H₂/CO ratios as low as 0.5 are acceptable feed.

Development Status

The LPMEOH technology won a Clean Coal Technology Demonstration award in the third round of solicitations. The project will be located at the Eastman Chemical Company's Kingsport, Tennessee, plant, where syngas from coal is produced at commercial scale to

make chemicals. The project seeks to make dimethyl ether (DME), as well as methanol. Coproduction of methanol and DME allows higher conversion of syngas per pass because some of the methanol is converted to the ether via dehydration. This avoids the unfavorable equilibrium limitations of the methanol synthesis reaction. The DME/methanol mixture can be burned as fuel without further modification or used as a feedstock for other fuels or chemicals.

Construction at Kingsport is scheduled to begin in 1995, and the plant will start in 1996.

There is a wide variety of other research underway on methanol synthesis, including novel methods for heat removal and temperature control, methanol removal during reaction to avoid the equilibrium constraints on conversion, and new catalyst formulations (including biocatalysts).

Environmental Performance

Methanol burns cleanly in either transportation or electric power generation situations. Since it contains oxygen, adding methanol to gasoline reduces emissions of carbon monoxide. On the other hand, methanol has a high vapor pressure, and evaporative emissions are a concern. Methanol has other drawbacks as a fuel: it is toxic and fully soluble in water; neat methanol will burn without a visible flame; and it therefore is viewed as more hazardous than common liquid fuels.

Commercial Impact

There is promise for making methanol from coal syngas in conjunction with other processes, most notably IGCC. This technique would process syngas on a once-through basis, accepting the limited conversion and using the remainder of the syngas in gas turbines to generate electricity. Elimination of the need to recycle unreacted syngas to the methanol process could make this configuration competitive with manufacture of methanol using low-cost remote natural gas. The methanol produced in this manner could be sold or used for "peak shaving" generation of electricity. Slurry-phase technology is unique in that it can be built to load follow the power generation demand, increasing methanol output when the need for power is low and even shutting down completely when demand is high.

Development Needs

Further investment of coal R&D dollars should be directed toward developing new approaches and catalysts for methanol synthesis that allow cost-effective coproduction of power, methanol, and other high value syngas derivatives such as MTBE and higher alcohols from coal based syngas.

Indirect Liquefaction (Fischer-Tropsch)

Technology Description

The Fischer-Tropsch (F-T) process polymerizes synthesis gas to produce a broad range of products, including light hydrocarbon gases, paraffinic wax, and oxygenates. There has been an enormous amount of R&D devoted to F-T processing over the past 20 years but only limited commercial exploitation of the technology. Typically, indirect coal liquefaction has a relatively low thermal efficiency. As with other products made from syngas, the feedstock considered in most cases for commercial production of F-T products is natural gas. However, Sasol has been operating a major facility in South Africa based on coal feed.

Sasol uses three different processes. Sasol I has been using Lurgi fixed bed F-T technology to make waxes for nearly 40 years. Capacity is 3,200 barrels per day (bpd) of gasoline plus diesel fuel. The Sasol Synthol process uses a circulating fluidized bed to make 110,000 bpd of light olefins and olefinic naphtha. A 2,400 bpd slurry-phase process was commercialized in 1993 making paraffins, olefins, and oxygenates.

A commercial development that is also of interest is the Shell Middle Distillate Synthesis (SMDS) process built in Malaysia and started up in 1993. Capacity is 12,500 bpd of kerosene and gasoil, components of diesel and jet fuels. Because these products are free of sulfur and completely paraffinic, they have very high value as blend stocks, and the economics for the process can be very attractive under the right circumstances (which include low-cost natural gas). The F-T process in Malaysia uses a multitubular fixed bed reactor and carefully designed catalyst and operating conditions to maximize the formation of high molecular weight waxes. The waxes are then hydrocracked to produce the final products. Although the original Shell R&D was focused on coal-generated syngas, the commercial embodiment uses natural gas as feed.

Development Status

Many other F-T processes have been tested at pilot plant scale, such as:

- Exxon Corporation recently completed a 10-year development of proprietary technology for converting natural gas to isoparaffinic products. The process was tested in a 200 bpd facility in Baton Rouge, Louisiana, between 1990 and 1993, with the longest run lasting over 400 days.
- DOE has sponsored work on slurry catalysts for F-T processing at LaPorte, Texas, following completion of the methanol synthesis program there. An iron-based catalyst was tested in 1992 with reportedly favorable results.

Environmental Performance

High-quality Fischer-Tropsch fuels for diesel and jet engines burn very cleanly, and with significantly lower air emissions from these devices, compared to traditional, petroleum-derived fuels. This is because F-T fuels are totally sulfur-free and aromatics-free. The fuels burn with less smoke and soot. Oxygenates can be included in the products, which can lower CO emissions as well.

Commercial Impact

There appears to be little likelihood of commercial use for Fischer-Tropsch technology using coal as the feedstock in the near future. Recent economic analysis under DOE sponsorship has shown that current slurry-phase F-T technology on a coal-based syngas is cost competitive at about a \$35 per barrel crude oil cost. However, it appears that a technical breakthrough is needed to significantly lower the costs further.

One niche for F-T technology on coal-generated syngas may prove to be attractive, similar to the once-through methanol process. The F-T plant would be built in conjunction with an integrated coal gasification combined cycle (IGCC) plant, and the F-T unit would operate in off-peak hours when the electric power was not required. The liquid product would be high value diesel fuel.

Development Needs

Projects aimed at new approaches to improving thermal efficiency, developing new catalysts, using low H₂/CO ratio syngas more effectively, or improving once-through processes may deserve DOE support at some time in the future.

C. Mild Gasification

Technology Description

Mild gasification, or pyrolysis, of coal involves the heating of coal in the absence of air or oxygen. Bonds in the solid coal matrix are thermally ruptured, and liquids and light hydrocarbon gases are released into the gas phase and swept out of the reaction vessel. Coal properties, temperature, heating rate, heating method, and other process parameters control the nature and relative amounts of products.

The advantage of this process is its simplicity compared to other coal conversion processes. It usually is operated at close to atmospheric pressure and at temperatures below 1000°F, so materials of construction need not be exotic. The volatile products are typically gases

at the higher temperatures and liquids. Heating can be quite rapid, which allows high coal throughput in small reactors. All of these features keep capital costs reasonably low.

The process has always suffered from a serious disadvantage. The quality of the liquid or gaseous products can be poor compared to products from other types of coal conversion processes. They may require extensive (and expensive) upgrading before they can be converted to conventional transportation fuels. This drawback prevents mild gasification from being considered seriously as a widely applied process for the production of traditional transportation fuels. However, the concept is finding opportunities for commercial application in niche markets.

Development Status

Fundamental pyrolysis reaction chemistry can be studied in relatively inexpensive, small equipment. This has led to an extensive literature on coal pyrolysis, generated in universities all over the world. Of all coal conversion technologies, pyrolysis may be the most widely studied and the best modelled. At least 6 domestic processes have undergone testing recently at pilot plant scale; two of these have been scaled up for further evaluation.

The ENCOAL process was tested by Shell Mining Company and SGI International at 0.1 tons per hour in the mid-1980s. The process uses a rotary grate pyrolysis unit and yields a liquid product. The liquid is not upgraded, but it is a proposed substitute for No. 6 fuel oil in boilers. A major advantage of this process is that it utilizes wet, low-Btu coal and produces a dry, high-Btu, low-sulfur solid product that can be shipped easily and safely. This process has been awarded support under DOE's Clean Coal Technology Demonstration Program, and a 1,000 ton/day demonstration plant is being operated near Gillette, Wyoming.

The IGT Mildgas process carries out pyrolysis in a reactor containing an entrained fluid bed on top of a bubbling fluid bed. The principal products are expected to be form coke, electrode binders, roofing material, activated carbon, and various aromatic chemicals. IGT has run a 100 pound/hour pilot plant and is working with a consortium of sponsors to build a 1 ton/hour process demonstration unit in Carbondale, Illinois. DOE is sponsoring the project under a competitive Program Research and Development Announcement (PRDA).

The Energy and Environmental Research Center at the University of North Dakota (UNDEERC) and the AMAX R&D Center evaluated a fast fluidized bed coal pyrolysis reactor in a 100 pounds/hour pilot unit. DOE provided support for the testing through the Morgantown Energy Technology Center. This process produced liquids and a solid product that were proposed substitutes for metallurgical coke, carbon black, and chemical feedstocks.

Western Research Center (WRC) and the AMAX R&D Center tested a fluid bed process for pyrolysis at 50 to 100 pounds/hour. The primary use for the char is in rubber tires or anode carbon for use in aluminum smelting. This testing was supported by DOE through the Morgantown Energy Technology Center.

The Calderon Energy Company has tested a process that produces gas via coal pyrolysis. This gas is converted to methanol. The char is then gasified with air, and the product is burned to produce electricity. A 1 ton/hour process development unit has been operating in Alliance, Ohio.

Other processes that have been tested at pilot scale in the past include Lurgi Ruhrgas (German), FMC COED, Occidental Petroleum's Flash Pyrolysis, Coalite (British), and SFUEL (Polish), among many others.

Environmental Performance

All mild gasification processes are capable of producing clean fuels; that is, solid, liquid, and gaseous fuels low in sulfur and nitrogen. Much of the sulfur and nitrogen reports to the volatile phase and can be removed to any reasonable level desired, using conventional technology. Sulfur and ammonia are the usual byproducts. The solid fuel is higher in mineral matter than the original coal, since usually about half of the organic matter is removed.

Part of the char product may be burned to supply process heat, and the flue gas must be treated to remove SO₂. Temperature for combustion is usually low enough that NO_x removal should not be necessary. Some coals also may raise concerns about air toxic emissions. The conversion process itself is fairly efficient because the heat required for pyrolysis is modest.

Commercial Impact

These processes have an opportunity for commercial use, but the market for the products being considered is smaller than that for commodity fuels. No more than a few commercial plants would be required to satisfy their target domestic market, but there may be significant international market potential for the technology.

Development Needs

It is recommended that current DOE-funded programs be completed. If private sector sponsors propose to fund the majority of the cost, then additional projects should be considered as part of any coal program.

D. Direct Liquefaction

Technology Description

Direct coal liquefaction involves the addition of hydrogen to coal in a solvent slurry at elevated temperature and pressure. A key function for the solvent is to shuttle hydrogen from the gas phase to the coal; it is also a convenient way to transport the coal into and through the process and enhances heat and mass transfer during the necessary chemical reactions. The elevated temperature increases the rate of chemical reaction and helps create liquid by breaking carbon-carbon bonds in the coal molecules. The high pressure keeps the solvent and products of the liquefaction reactions in the liquid phase at these temperatures and promotes hydrogenation by maintaining a high partial pressure of hydrogen. Catalysts are used to increase the rates of the desirable reactions.

Coal type and properties have a strong effect on how the coal behaves during liquefaction. Anthracite and low-volatile bituminous coals are too deficient in hydrogen to make attractive feedstocks for direct liquefaction. At the other end of the spectrum, coals with high oxygen levels are also undesirable, since the oxygen must be removed as either water or carbon dioxide; the former wastes hydrogen, and the latter decreases process thermal efficiency. The best feedstocks are either high volatile bituminous or sub-bituminous coals, which contain large amounts of hydrogen and modest amounts of oxygen. As much as 5 barrels of gasoline can be made from each (moisture free, mineral matter free) ton of such coals.

Most often, the reactions are carried out in two stages; single stage processes generally give lower yields of desirable products, and attempts to reduce the process to a single stage have largely been abandoned in recent years. In broad terms, the first stage is used to dissolve the coal and the second is used to upgrade the liquids produced. Mineral matter, catalyst, and unreacted coal are separated from the liquids; the liquids are then upgraded further to produce finished transportation or boiler fuels. Upgrading includes the removal of oxygen, sulfur, and nitrogen so that the finished products have minimal environmental impacts.

Substantial hydrogen must be added to the coal to produce specification liquid fuels. Hydrogen today is most economically manufactured from natural gas, but it seems likely that coal gasification will be more cost-effective by the time direct liquefaction becomes economically attractive.

There are significant economies of scale involved in direct coal liquefaction, primarily in the liquid upgrading end of the plant. A single grass-roots commercial plant based on current technology would cost billions of dollars to build. An alternative is to build coal liquefaction facilities as additions to oil refineries so that existing equipment could be used

to perform the upgrading. However, significant cost and risks will be incurred to adapt the refinery to coal liquid products.

One refinery integration technique involves processing heavy oil and coal simultaneously under severe hydrotreating conditions. Some refineries already have such hydrotreaters operating on heavy petroleum fractions. The concept has the virtue of requiring far less new capital equipment than either a grass-roots coal liquefaction plant or even other types of refinery add-ons, where the liquefaction reactors are separate vessels. DOE promoted this concept in the late 1980s, and one such project was part of the Clean Coal Technology Demonstration Program. However, that project failed to secure sufficient private sector funding and was dropped.

Development Status

Direct coal liquefaction has been undergoing development since it was discovered in the 1920s by Bergius, but it has not been used to make commercial amounts of fuels since World War II. Both the Electric Power Research Institute and the DOE have been involved in such development since their founding. The Arab Oil Embargo of 1973 focused attention on this area, and for almost 20 years direct liquefaction was a centerpiece of the U.S. synthetic fuels effort.

Two large pilot plants (200 to 250 tons/day feedrate) were built in the late 1970s under sponsorship of DOE. The EDS (Exxon Donor Solvent) process was tested in Baytown, Texas, and the H-Coal process was examined in Catlettsburg, Kentucky. These facilities tested and validated a wide variety of modern equipment at a scale large enough to minimize the risks of commercial operation, but the costs were too high to justify commercial demonstration. From 1983 through 1992, there were a variety of smaller pilot plants operating in the U.S., many under DOE sponsorship, including the Advanced Coal Liquefaction Pilot Plant in Wilsonville, Alabama.

A variety of process improvements were demonstrated at Wilsonville between 1983 and 1987. There were no radical changes in the technology, but there was a steady accumulation of evolutionary improvements that ended up reducing the projected cost for commercial production of liquid transportation fuels from coal by about 60 percent over that 5-year period. In 1987, coal liquids could compete with fuels derived from petroleum at a crude oil price of \$35/bbl. It should be noted that this technology has never been demonstrated at large scale.

The Wilsonville pilot plant remained in operation through 1992. Since that time, DOE has been sponsoring further development of direct liquefaction at a reduced level of funding; included is operation of a somewhat smaller pilot plant at HRI in Trenton, New Jersey. Significant improvements continued to be made.

However, there has been no reduction in the cost of producing liquid fuels from coal since 1987. The savings due to process improvements have been offset by inflation in construction and operating costs and by decreases in the value of the products of coal liquefaction. Coal liquids were attractive gasoline components because their aromatic character made them high in octane, but the Clean Air Act Amendments of 1990 limited the amount of aromatics that could be used in gasoline. Over the same period, petroleum prices actually have decreased.

The University of North Dakota Energy and Environmental Research Center recently announced the development and patenting of a process to liquefy low rank coals. It is claimed that the DOE-sponsored research has achieved coal conversions exceeding 95 percent and liquid yields of almost 75 percent of the moisture-free and ash-free coal. They currently are seeking private sector and DOE funding to continue process development.

DOE has established a near-term goal to make direct coal liquefaction competitive with petroleum at \$25/bbl. This seems overly optimistic. The minimal funding available is unlikely to allow the technology to develop fast enough to offset inflation unless a technical breakthrough is achieved.

Environmental Performance

Liquids made from coal are all clean-burning; the process removes almost all of the sulfur and nitrogen native to the coal. Sulfur and ammonia are byproducts of the conversion process. The unconverted coal and heaviest liquid products are burned in a fluid bed to drive the conversion process or are converted into hydrogen via partial oxidation. Both of these processes control emissions to a very low level as well.

The ash from the process is similar to ash produced from a power plant using the same type of coal and offers the same sort of environmental concerns. In addition, the solids can contain metals from the catalysts used in the process, either molybdenum or iron. It is not likely to be economically attractive to recover the molybdenum, but this should not be a significant disposal problem.

There are concerns about spills of intermediate streams in the liquefaction plant. Incompletely upgraded coal liquids can be high in polynuclear aromatic hydrocarbons and must be handled with care and respect. The plant design must minimize the chances for spills and allow such spills to be contained if they occur.

Experience at the Wilsonville pilot plant showed that process water could be treated by conventional means and cleaned to drinking water standards.

The products themselves are not significantly different from similar products derived from

petroleum, but the conversion process has a thermal efficiency of only 67 percent, while conventional petroleum refining is at least 90 percent efficient.

Commercial Impact

Direct coal liquefaction could become the process of choice for the production of gasoline in the United States if and when petroleum supply becomes inadequate to meet worldwide demand. However, it will not become widely used on a commercial basis unless there is a breakthrough in technology, or unless the price of crude oil rises to a stable high level.

Coprocessing coal and heavy petroleum fractions in oil refinery equipment is unlikely to be attractive before direct liquefaction. The existing hydrotreating equipment in refineries is seldom suitable for handling coal. Refinery equipment has temperature and pressure limits that put it on the lower edge of the desirable range for coal processing. Most important, such equipment is designed for much lower hydrogen consumption than coal processing would require.

Development Needs

Technologies as complex as direct coal liquefaction do not survive well "on the shelf." Much of the German technology developed before World War II was reinvented during the 1970s and 1980s because the original technical experts were no longer available to guide the effort. The Federal Government has played the role of technical caretaker successfully in the past, a notable example being the Bureau of Mines efforts in retaining and improving oil shale retorting technology between the 1920s and 1973. DOE should consider structuring its programs to perform the same sort of function for direct coal liquefaction technology today.

On the other hand, there is little incentive for a significant development effort involving today's technology. Rather, there is a need to support a strong effort in understanding fundamental coal structure and chemistry and to provide funds to test new concepts in direct liquefaction at least through pilot plant evaluation. The work would be carried out best in university and other private sector laboratories, with perhaps a National Laboratory as a focal point for the programs.

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E. Other Conversion Technologies

Solvent Extraction

Technology Description

Solvent extraction of coal traditionally has been used as an analytical tool to isolate and characterize particular fractions of the organic material. Much less frequently, solvent extraction has been proposed as a technology for converting coal to clean fuels on a commercial scale.

The basic concept is simple. The coal is added to a tank of solvent and mixed for some short period of time. The undissolved solids are then separated by hydrocyclones, filtration, centrifugation, or some other solid-liquid separation (SLS) technique. The portion of the coal in solution is then separated from the solvent by evaporation or precipitation, then upgraded as necessary to make the desired product fuel.

Such processes would require excellent recovery and reuse of solvent, good extraction yields, and low-cost SLS technology to be attractive economically.

Development Status

Solvent refined coal was the goal of several major projects in the late 1970s and early 1980s. These processes sought to extract clean portions of the coal (leaving behind the sulfur) using a coal-based solvent. The pilot plant in Wilsonville, Alabama, built by Southern Company Services and EPRI was designed originally to produce solvent refined coal. A similar process was piloted by Gulf Oil in Tacoma, Washington. Neither of these processes proved to be commercially attractive. Attention became focused on upgrading the dissolved material in a second reaction vessel, and the technology evolved into two-stage direct liquefaction.

A group at the Kentucky Energy Cabinet Laboratory studied the use of various solvents on Kentucky coals. They were able to dissolve over 80 percent of one West Kentucky sub-bituminous coal in ethanenediamine at 580°F. However, there was significant solvent incorporation into the product, and the concept was not pursued.

Environmental Performance

Solvent losses must be controlled to protect the environment, as well as to achieve acceptable product cost. Solvent potentially can be lost by evaporation (for light solvents), solubilization in process water, or incomplete recovery from the solid product. Very low concentrations in any emitted stream can quickly add up to high overall losses because the

volume of solvent used is large.

The fuels produced by solvent extraction will be much cleaner than the native coals but will not be nearly as free of potential pollutants as fuels from direct or indirect liquefaction. On the other hand, solvent-based processes can be more efficient than those more severe conversion processes.

Commercial Impact

There are no solvent-based processes developed enough to evaluate commercial impact.

Development Needs

There is merit in exploratory research relating coal solvent extraction to coal and solvent properties.

Bioconversion

Technology Description

Bioconversion of coal into clean fuels (and chemicals) is a relatively new area of technology. Bioconversion in the precombustion process to remove sulfur from coal is covered in Chapter III, Part A. DOE and EPRI both have sponsored a limited amount of research in biological coal conversion since the late 1980s. There is no complete process at this point -- only clues that a process might be possible.

Development Status

One concept supported by DOE is to use microorganisms to convert the pyrite in coal to a form of iron that will act as a catalyst for direct liquefaction. Some success with *Thiobacillus ferrooxidans* has been reported, although the iron seemed to precipitate preferentially on the surface rather than evenly through the coal.

Another concept (sponsored by EPRI) has been to liquefy low rank coal using cell-free enzymes from cultures of *Polyporus versicolor*. This procedure has been fairly successful only with leonardite, a very low rank material, up to 70 percent of which was solubilized.

A strain of *Penicillium* has also been reported to dissolve 60 percent to 93 percent of Illinois No. 6 coal that had first been pretreated at 300°F in air for seven days. The mechanism is said to be attacked by the fungal enzymes on the new carbon-oxygen bonds. Through an oxidative hydrolysis, this attack can open aryl rings to form carboxylic acids, which are soluble in basic solution.

Bench scale work at the University of Arkansas, sponsored by DOE, investigated direct conversion of coal using microorganisms, followed by gasification of these liquids. The syngas is then converted to acetic acid or ethanol, again using microorganisms. The conversion of syngas to acetic acid has been advanced to the pilot plant stage by Engineering Resources, Inc., although the source of syngas is expected to be from carbon black manufacture.

Engineering Resources, Inc., also is studying the upgrading of coal liquids using bioprocessing. The anaerobic bacteria being used seem to incorporate sulfur and nitrogen compounds into their cell mass.

Environmental Performance

It is too early to assess the environmental problems which may be derived from the use of these processes.

Commercial Impact

Of the bioprocessing options being studied, none of the coal conversion processes seems to be moving forward very quickly.

Development Needs

DOE has supported biotechnology development for coal conversion, but the incentives for fuel production have not been sufficient to generate strong interest. An effort should be devoted to increasing interest in improving reaction rates and seeking mimetic catalysts.

Coalbed Methane

Technology Description

The recovery of methane from coal seams is by extraction of the gas from the coal "rock," which acts as a gas reservoir. Recovery of methane was not considered by geologists for many years because the coal tends to adsorb the gas inside its pores. The mechanisms for recovery of the gas were not well understood until recently. Over the past ten years, research has identified key issues in the following areas that have resulted in significant deployment in coalbed methane recovery:

- Understanding the fundamentals of production.
- Advances in well testing and permeability measurement.

- Understanding cavity production.
- Reservoir modeling.

To predict accurately the amount of gas available in a coal seam and to recover it, the operator must determine the amount of gas adsorbed in the seam and be able to predict the diffusion rate at which it can be removed. Also, since most coal seams act as water reservoirs, the water acts to maintain the pressure in the seam. The water must be removed from the coal seam to allow a differential pressure sufficient to extract the gas from the coal matrix.

Most wells require extensive dewatering before any gas is produced. Lowering the well pressure as much as possible is the objective of gas recovery wells. Once production begins, much of the gas brought to the surface is mixed with water, resulting in two-phase flow. Another key issue for the operator is to find a means to dispose of the water produced with the gas.

Development Status

In 1983 there were 165 coalbed methane wells in the United States. This increased to over 6,500 wells by the end of 1993. Total production from these wells is in excess of 705 BCF per year, up from only 6 BCF in 1983. The San Juan Basin in New Mexico and Colorado and the Black Warrior Basin in Alabama have been the leading areas for extraction of this resource. Early production began as a method to remove gas prior to mining. Now the gas is extracted on many projects exclusive of any connection with mining operations. Early production costs were as high as \$5.00 per MCF, while current technology allows recovery at about \$1.18 per MCF.

The amount of coalbed methane resource varies considerably by region across the country. The total reserves in the U.S. are estimated to be 401 TCF.

Over the past several years, advances have been made in both well completion and stimulation techniques. It is important that wellbore completion be conducted in a manner to prevent the intrusion of coal fines. Stimulation techniques also have been developed to allow for multiple seam penetration and for seam depth propagation fracture distances of about 400 ft. This has greatly improved coalbed methane economics. GRI and the Society of Petroleum Engineers have published guidelines that assist developers in the design of coalbed methane extraction systems.

Much of the early coalbed methane recovery work was stimulated by the availability of Section 29 tax credits. These incentives yielded benefits of \$0.66 to \$0.93 per MCF from 1982 to 1990. These incentives allowed early production products to remain profitable and

contributed to the impetus to continue research efforts to improve the technology.

Additional research is considered valuable to the technology in the areas of interpretation of multi-phase flow and more detailed reservoir characterization, particularly in lesser producing coal seams. Among other issues that need further research is finding alternative low-cost water disposal options.

Environmental Performance

Recovery of coalbed methane provides a valuable contribution to reducing atmospheric methane resulting from future coal mining efforts. Methane is a "greenhouse gas" that is considered to have 10 to 20 times the "greenhouse effect" that an equivalent amount of carbon dioxide would have. Recovery of this gas before mining significantly reduces the amount of methane liberated to the atmosphere when mining is conducted.

A key issue for the industry is the disposal of water pumped from the coal seam during extraction. Most producers reinject the water back into deep wells. This accounts for 55 percent to 65 percent of the water collected from gas wells. About 30 percent to 40 percent is treated in surface facilities, which are more expensive. Other methods are used for about 5 percent of the water from coalbed methane wells. This water can contain dissolved and suspended solids and small quantities of organic materials. Research on alternative, low-cost disposal methods is still needed.

Commercial Impact

The extraction of coalbed methane has made a significant contribution to the natural gas supply resource over the past few years. To date, most of the well completions have been in coal seams that have demonstrated high yields at today's comparatively low prices. The availability of tax credits helped spur the industry through the early deployment phase of the technology. High prices or renewed tax supports will be needed if the resource is to be exploited fully in all areas of the country. The ownership issue is still a barrier to development in several states (does gas belong to the coal, oil and gas, or surface rights holder?).

Development Needs

Continued research efforts can aid in the further exploitation of this valuable resource. Research is needed to develop better low-cost disposal methods for the water pumped from the wells to extract the gas. Detailed reservoir data for coal seams that have not been fully characterized also will aid in the further utilization of more of the resource, as the economics justify installation of new facilities.

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Underground Coal Gasification

Technology Description

Underground coal gasification (UCG) is the process of converting the coal to a gaseous product "in situ." The coal is converted to a gas by igniting it in place to provide the heat of reaction. Air or oxygen and steam are then injected into the coal seam via injection wells where the gasification reactions then occur. Products are extracted from the seam via a set of collection wells.

Surface gasification allows for tight control of the conditions inside the gasifier vessel. In underground gasification, the geological environment of the coal seam and the hydrogeological setting impose constraints over the gasification environment in the seam. The design of the UCG facility is dependent on these factors and must be tailored specifically to the coal and the site.

An attractive aspect of the process is that it can be used to extract energy from coal seams that cannot be recovered effectively by traditional mining techniques. This is a reason why the technology development has focused on deep, thin seams and on steeply dipping seams.

Development Status

Experimental work began in the USSR during the 1930s. By the 1940s, the USSR was using UCG to provide illuminating gas at five locations. Operational improvements were made by the USSR during the 1950s. With the discovery of natural gas in the USSR in the mid-1960s, operation of UCG facilities was discontinued. A number of European countries also experimented with UCG from the 1940s to the 1960s. Following World War II, the development of UCG technology was conducted in the U.S. Testing was conducted at a number of U.S. sites to develop an understanding of the process and the factors that influence product efficiency.

Early tests exhibited poor utilization of the coal in the test seams. Tests were developed to determine more about the conditions that occur in the well during the gasification process. Tests were conducted by DOE (and its predecessor, ERDA) to investigate the reverse combustion linking. These tests used advanced well monitoring techniques and extensive gas monitoring to evaluate the data. Testing during the 1970s and 1980s was conducted using directional drilling. Problems with excessive water influx into the reaction zone needed to be resolved.

The most recent tests were conducted near Hanna, Wyoming, and were funded by DOE and GRI. The tests were conducted in 1987 and 1988. During these tests, which used steam and oxygen, a procedure to minimize the impact of UCG on local groundwater

quality was developed. These tests demonstrated the importance of understanding the interaction between the process and the hydrogeology of the coal seam as the key to successful commercialization of UCG.

Environmental Performance

The raw gas that is extracted from the wells is not suitable for direct utilization. Cleanup of the gas is handled very much the same as by the processes described for surface gasification. Once cleaned, the gas has all the same properties, except heating value, as gas from typical gasification processes conducted in a pressure vessel.

One issue is the contamination of groundwater that flows through the coal seam. The groundwater can be contaminated with tars and phenols if the process is not controlled properly. A key element in preventing contamination is proper selection of the coal seam to insure that there are no aquifers providing potable water fed by it. The other key factor is that the injection process must be managed properly to ensure complete fuel utilization in the well and thus eliminate the materials that can contaminate the surrounding water.

Commercial Impact

The UCG technology currently is being developed by Energy International Corporation (EI), a division of Williams Energy Ventures. EI is planning to install and operate a UCG demonstration facility in Rawlins, Wyoming. This facility will draw upon the work previously conducted with DOE funding. EI plans to install a facility to make either synthetic natural gas or ammonia. Power generation also is planned for this facility. A key factor in the financing of this technology will be the availability of Section 29 tax credits. EI also has performed feasibility studies for facilities in Spain and New Zealand.

Continued deployment of UCG will require sustained operation of commercial facilities to demonstrate the viability and financial integrity of this technology. This demonstration can be encouraged by extension of the Section 29 tax credits beyond the current expiration date of December 31, 1996.

Development Needs

Underground coal gasification technology will benefit from the planned commercial demonstrations in Rawlins, Wyoming, for determining the key issues related to the gasification aspects of the technology. Key downstream issues concerning gas cleanup will benefit from surface gasification projects funded under the Clean Coal Technology Program. Hydrology issues around the site will require careful monitoring to ensure protection of the environment.

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F. Coal for Iron and Steel Production

The Iron and Steel Industry is experiencing rapid technological change. Many new technologies are being created, developed, and commercialized. The vast majority of these technologies will require significant quantities of coal. Many of them are aimed at improving or replacing the traditional coke oven/blast furnace route for hot metal (liquid iron) production. Blast furnace coal injection and COREX[®] are regarded as commercial/near commercial technologies. Other developing technologies include AISI direct iron/steelmaking, Japanese DIOS, Australian Hismelt, and Russian Romelt.

While the pulverized coal injection technology is an improvement on existing blast furnace operations, all the other technologies are intended to replace the traditional coke oven/blast furnace technology.

Blast Furnace Coal Injection

Technology Description

Coal can be injected into a blast furnace in either a pulverized or granulated form. The objective of this technology is to reduce the amount of coke required to produce hot metal in a blast furnace. By reducing the demand for coke, coal injection improves the environment. It also reduces costs and increases blast furnace productivity by reducing the amount of furnace volume needed for coke and, hence, increasing the amount of furnace volume available for iron ore.

The benefits of blast furnace coal injection include:

- Environmentally attractive -- reduced dependence on coke (reduction of up to 400 lbs. coke per ton of hot metal).
- Increased blast furnace productivity.
- Reduced costs.

Development Status

Blast furnace coal injection is widely practiced by the steel industry, especially outside of the United States. Coal injection rates as high as 400 pounds per net ton of hot metal have

been demonstrated successfully. Within the domestic steel industry, numerous blast furnaces have been converted to coal injection, and the technology continues to make significant inroads.

DOE, in cooperation with Bethlehem Steel Corporation, is in the process of demonstrating this technology for the first time in the United States.

Commercial Impact

If blast furnace coal injection is adopted successfully by the entire domestic steel industry, as much as 10 million TPY of coal would be required.

COREX[®]

Technology Description

In the COREX[®] process, molten iron (hot metal) is produced by continuous reduction and smelting of iron ore in two integrated unit operations -- a shaft furnace and a melter gasifier. Clean, low-Btu (175 Btu/scf-220 Btu/scf) export gas generated in the process can be used to fuel a combined cycle power plant to generate electricity. Using coal as the energy source, CPICOR[™] -- Clean Power from Integrated Coal/Ore Reduction (COREX[®]) -- produces both clean electric power for utility distribution and hot metal for use in steelmaking.

CPICOR[™] can be operated with a wide range of coal qualities, expanding the use of the vast coal energy reserves in the U.S. Technologies like CPICOR[™] will contribute significantly toward national goals of "clean energy from coal" and "energy independence."

The benefits of COREX[®] technology can be summarized as follows:

- Highly developed alternative hot metal source -- ISCOR, POSCO.
- Environmentally attractive -- eliminates coke ovens.
- Generates power as byproduct.
- Reduced hot metal costs.

Development Status

ISCOR in South Africa built the first COREX[®] plant in the late 1980s. It is a 1,000 ton

per day (C-1000) plant which has been operating on a commercial basis for about five years. The export gas from the plant is used for miscellaneous heating applications within ISCOR's Pretoria Works. POSCO of South Korea is constructing a COREX[®] C-2000, which is expected to be operational by the end of 1995.

DOE, under Round 5 of its Clean Coal Technology Program, selected a proposal to demonstrate a COREX[®] C-3000 plant in conjunction with a combined cycle power plant (CPICOR[™]). The CPICOR[™] Project will demonstrate a 3:1 scale-up of the COREX[®] process to a nominal 3,200 tons per day of hot metal, with the coproduction of approximately 200 MW of net export electrical energy. The Project will utilize data generated from the very successful operation of a COREX[®] demonstration plant in Pretoria, South Africa. Today, the technology is ready for a commercial-scale demonstration at a viable host site in the United States to prove that it can indeed serve as a cost-effective replacement for coke plant/blast furnace ironmaking technology by producing a high quality hot metal for U.S. steel industry needs. Most important, this proposed demonstration for the first time will accomplish the successful integration of the COREX[®] process with efficient generation of electricity in an adjacent combined cycle power plant. This is the most efficient and environmentally attractive way to utilize the export gas generated by the process.

Environmental Performance

CPICOR[™] technology is less complex and environmentally superior when compared to competing ironmaking and power generation technology. All criteria air pollutants are reduced by more than 85 percent, due largely to the inherent desulfurizing capability of the COREX[®] process and the efficient control systems within the combined cycle power generation (CCPG) facility. The serious challenge of reducing emissions of hazardous air pollutants (air toxics) from coke plants is met by CPICOR[™]. Coal, and not coke, is fed directly to the COREX[®] melter gasifier. Hence, CPICOR[™] eliminates the coke plant and its inherent problems of controlling fugitive emissions and toxic and hazardous releases.

The energy efficiency of the CPICOR[™] technologies is over 35 percent greater than competing commercial technology when consideration is given to the production of both hot metal and electric power. Much of the efficiency advantage of the CPICOR[™] technology is gained from more effective use of the sensible heat and volatile matter as compared to the cokemaking process. In addition, the CCPG achieves energy efficiencies of nearly 50 percent.

Commercial Impact

The commercial impact of COREX[®] technology is expected to be substantial. A typical COREX[®] C-2000 plant will utilize 700,000 tons per year of coal and produce 120 MW of

power and 750,000 tons per year of hot metal. If the existing hot metal production in the United States were replaced with COREX[®] technology, 45 million to 50 million tons per year of coal would be required. On a worldwide basis, coal requirements would be approximately ten times the domestic potential.

AISI Direct Iron/Steelmaking

Technology Description

The AISI direct iron/steelmaking process was intended originally to result in the direct production of steel from iron ore. Based on research findings, the project now is aimed at developing, in the intermediate term, a direct ironmaking process. Iron ore is fed into the top of the pre-reduction vessel while reducing gas produced via the gasification of coal with oxygen is injected at the bottom of this vessel. This iron ore is partially reduced to wustite (FeO), which is charged into the top of the in-bath smelting vessel.

Coal and oxygen also are charged into this vessel, and the carbon reacts with the FeO, forming liquid iron, or hot metal, at the bottom of the in-bath smelting vessel. In addition to gasifying coal, some of the oxygen is injected to burn some of the CO to CO₂ within the in-bath smelting vessel. This practice is known as postcombustion, and it minimizes the amount of coal needed per ton of hot metal and reduces the amount of excess offgas which has to be utilized in an economically efficient manner.

The benefits of the AISI process can be summarized as follows:

- Environmentally attractive -- eliminates coke ovens.
- Reduces costs.
- Postcombustion minimizes export gas production -- less complex commercially.

Development Status

The process has been developed to the pilot plant scale, but significant development efforts are needed at a near commercial size facility before the technology can be considered available for commercial use. As with the other technologies in the developing category, the AISI direct ironmaking process is a number of years away from achieving commercial/near commercial status.

This process development is being supported by the Iron and Steel Institute and DOE under its Metals Initiative Program.

Commercial Impact

If eventually commercialized, the impact of AISI direct iron/steelmaking would be significant. A typical 2,000 TPD of hot metal AISI process would consume about 320,000 TPY of coal. If all domestic hot metal were to be made with this process, 20 million to 25 million TPY of coal would be required.

Japanese DIOS Technology

The Japanese DIOS technology is a direct reduction iron ore process. The DIOS process uses fine ore directly in a fluidized bed for pre-reduction prior to final smelting in the smelting reduction furnace. This technical approach eliminates the need for iron ore agglomeration and, thus, the cost associated with this process step.

The benefits of the DIOS process can be summarized as follows:

- Environmentally attractive -- eliminates coke ovens.
- Reduces costs.
- Postcombustion minimizes export gas production -- less complex commercially.
- Eliminates iron ore agglomeration.

Development Status

DIOS development is being undertaken by the Japan Iron and Steel Federation (JISF) with the support of MITI, the Japanese Ministry of International Trade and Industry. A 500 TPD hot metal pilot plant has been constructed in Japan and presently is undergoing testing, which is expected to be completed by 1995.

While this technology is being tested at a very significant scale, it would still have to be scaled up by a factor of 2 to 4 in order to reach commercial size. DIOS direct ironmaking is still a number of years away from achieving this commercial size.

Commercial Impact

If DIOS technology is commercialized, it will have significant impact. While accurate figures are not available, it would be reasonable to assume that the DIOS process would have an impact similar to the AISI process and that, therefore, if all domestic hot metal were to be made with DIOS, 20 million to 25 million TPY of coal probably would be required.

Australian Hismelt Technology

Technology Description

The Hismelt process is a smelting reduction process which utilizes fine ore, coal, and air to produce hot metal directly. The process does not utilize coke and therefore is environmentally advantageous when compared to the traditional coke oven/blast furnace route to hot metal production.

Hismelt technology benefits include:

- Environmentally attractive -- eliminates coke ovens.
- Uses iron ore fines -- no agglomeration necessary.
- Air-based -- low energy content export gas results in reduced commercial complexity at the expense of reduced export gas credits.
- Reduces costs -- especially raw materials costs.

Development Status

The Hismelt Joint Venture is a 50/50 collaboration between CRA Limited of Australia and Midrex Corporation of Charlotte, North Carolina. They constructed a large pilot scale (100,000 TPY of hot metal) Hismelt facility in Australia which began operation in October 1993. While the Hismelt plant in Australia has achieved only about 60 percent of design capacity to date, the Hismelt Joint Venture is confident that full design capacity will be achieved as individual unit processes within the plant are brought up to full speed.

As with the other processes in this developing technology category, Hismelt direct ironmaking is a minimum of 5 to 10 years away from achieving commercial/near commercial status. Once testing is completed at the 100,000 TPY facility in Australia, a 5 to 1 scale-up to a production capacity of 500,000 TPY of hot metal is the next step proposed by the process developers.

Commercial Impact

The Hismelt process is projected to use approximately 0.8 tons of coal per ton of hot metal produced. If commercialized, a typical 1,700 TPD hot metal Hismelt process would consume about 400,000 TPY of coal. If all domestic hot metal were to be made with the Hismelt process, about 40 million TPY of coal would be required.

Russian Romelt Technology

Technology Description

The Romelt process was developed by the Moscow Institute of Steel and Alloys with the cooperation of the Novolipeski Metallurgical Kombinat in Russia. The process was developed to convert waste iron oxide materials into hot metal. Testing in Russia indicates that the process also has the potential to convert iron ore directly into hot metal. Iron ore and any other iron bearing material is fed directly (without agglomeration) into the Romelt furnace. Coal also is charged into the top of the furnace, and oxygen or oxygen-enriched air is blown through two rows of tuyeres. The high slag content in the furnace undergoes severe agitation and creates both tremendous surface area and slag rotation for capture and return of the postcombustion heat to the hot metal bath. This process has the potential to operate with some of the highest postcombustion levels of any direct ironmaking process currently under consideration.

Romelt process benefits include:

- Environmentally attractive -- eliminates coke ovens.
- Uses fine ore or waste materials -- no agglomeration necessary.
- Potentially very low-cost -- especially capital.
- High levels of postcombustion could minimize export gas -- less complex commercially.

Development Status

A pilot plant has been operating intermittently since the mid-1980s in Lipetsk, Russia. The plant was intended as a research and development facility and has never operated for more than two consecutive weeks. While designed for 40 tons per hour productivity, the maximum production achieved has been 18 tons per hour, due mainly to limitations with water cooling and offgas handling capacity. While significant development work has taken place, the Romelt process needs to be demonstrated on an ongoing basis at a large pilot plant scale and then proceed to its first commercial scale operation. These development needs indicate that Romelt probably will not reach commercial/near commercial status in the next few years.

Commercial Impact

The Romelt process would appear to be best suited for recycling waste iron oxide materials. However, if it were to be commercialized as a direct ironmaking process, it

would have significant impact. A typical 2,000 TPD of hot metal Romelt process based on iron ore and coal would consume about 600,000 TPY of coal. If domestic hot metal were to be made with this process, about 40 million TPY of coal would be required.

Development Needs

Blastfurnace coal injection, COREX[®], and AISI direct iron/steelmaking technology developments presently are being supported by DOE. It is recommended that DOE complete the coal injection and COREX[®] projects under the CCT program and make a thorough evaluation of the waste oxide technology niche for the AISI direct iron/steelmaking technology. Varying kinds of domestic coals should be tested in these technologies to determine their applicability. The development status of all promising technologies should be monitored, and cost estimates should be made for use in future commercialization activities.

Appendix A

Exhibits

EXHIBIT 1

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Precombustion				
1. PHYSICAL COAL CLEANING	Hazardous Air Pollutants (e.g. Cl, Hg) & Alkali Removal	N/A	Complete CCT Demonstration	International Marketing Assistance
2. CHEMICAL COAL CLEANING	N/A	N/A	N/A	N/A
3. BIOLOGICAL COAL CLEANING	Kinetics; Economics; Agents Selectivity	N/A	N/A	N/A
4. NEW FUEL FORMS				
Low Rank Coal Beneficiation	N/A	Continue the LRC Beneficiation Program	Complete Demonstration	International Marketing Assistance
Micronized Coal	N/A	Emphasize Development	N/A	N/A
Coal Liquid Slurries	N/A	N/A	No _x Reduction Potential; GOB Pile Utilization	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Combustion				
1. ADVANCED PULVERIZED COAL-FIRED BOILERS	Chemistry of Coal Combustion; Co-firing; Advanced Materials	Improvement in Burner Design	Large-Scale Demonstration Incl. 1100°F Steam Cycle (Complete LEBS Program); Integrated Support of High Temp. Materials	N/A
2. ADVANCED COMBUSTION				
Low NO _x Burners	N/A	Furnace Mod. w/ Over-fire Air and Reburn. Technologies	Carbon Utilization; Hot Spots; Slagging	N/A
Over-Fire Air	Furnace Corrosion	N/A	Operating Exper.; Extend Test Periods	N/A
Coal Reburning	N/A	N/A	Further Demon. on Cyclone Boilers	N/A
Slagging Combustor	N/A	N/A	Complete Demon. Project; Econ. Study	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Combustion (Continued)				
3. ATMOSPHERIC FLUIDIZED BED COMBUSTION	Improved Refract. Matls.; Reduced Emissions; Integr. Design	Internal Recirculation Design; S. Capture; Sorbent Use; Adv. Materials Testing; Co-Firing of Biomass	N/A	N/A
4. PRESSURIZED FLUIDIZED BED COMBUSTION	Hot Gas Clean-Up In-Bed Tube Material; Sorbent Utilization	Integration Studies with Carbonizer; Accelerate Topping Combustor Develop.; Higher Gas Turbine Inlet Temperature; HGCU Develop.; Alkali Control; Efficient Use of Ash	Complete CCT Projects; Economics Study	Risk Sharing

EXHIBIT 1 (Continued)

RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Postcombustion				
1. DESULFURIZATION				
Wet	N/A	Improved Mist Eliminator (High Velocity Scrubbers)	N/A	Risk Sharing for Process Improvements
Dry	N/A	N/A	Reagent Utilization	N/A
Regenerable Wet	N/A	N/A	N/A	N/A
Sorbent Injection	N/A	Sorbent Utilization & SO ₂ Removal Efficiency	N/A	International Marketing Assistance

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Postcombustion (Continued)				
2. DENITRIFICATION				
Selective Catalytic Reduction (SCR)	Advanced Catalyst Formulations; (Minimize Catalyst Poisoning and SO ₂ Oxidation)	N/A	Complete CCT Projects	N/A
Selective Non-Catalytic Reduction (SNCR)	N/A	Development of On-Line Ammonia Monitor; Cycling Requirements	Expand Temperature Range for Maximum Effectiveness	N/A
SO _x /NO _x	N/A	N/A	Complete Demonstration for Economic Evaluation	N/A

EXHIBIT 1 (Continued)

RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Postcombustion (Continued)				
3. PARTICULATES				
Electrostatic Precipitators	N/A	PM < 10 Microns; Hazardous Air Pollutants (HAPs) Control Assessment	N/A	N/A
Fabric Filters	N/A	PM < 10 Microns; Hazardous Air Pollutants (HAPs) Control Assessment	N/A	N/A
Advanced Technologies	Evaluation of Condensing Heat Exchanger; Fine Particulate Control	N/A	N/A	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Technologies Related to Power Generation: Postcombustion (Continued)				
4. BYPRODUCT UTILIZATION	Byproduct Characterization; Immobilization of HAPs; SO ₂ /NO _x Control Agent Effects on Byproducts	N/A	Utilization of All Solid Streams	Develop National Utilization Standards
5. HAZARDOUS AIR POLLUTANT CONTROL	Characterization Studies; Control System Configuration	Hg Characterization and Control Technology Development; Develop Experimental Methods & Test Protocol	Characterize and Demonstrate Promising CCT Demonstration Technologies	N/A
6. CARBON DIOXIDE CONTROL	Selective CO ₂ Removal and Sequestration Development	N/A	N/A	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
	Technologies Related to Power Generation: Integrated Coal Gasification Combined Cycle			
1. IGCC	N/A	Hot Gas Clean-Up	Continue CCT Project Demonstration; IGCC/Adv. GT Demo	Risk Sharing

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
		Other Advanced Systems		
A. ADVANCED GAS TURBINE COMBINED CYCLE	High Temp. Alloys; Recuperators	Oxid./Corrosion Resistant Coatings; Catalytic Combustion	AGT/IGCC System Demo; AGT/PFBC System Demonstration	N/A
B. INDIRECT FIRED CYCLES	N/A	Heat Exchanger Ceramics; High Temperature Valve	Complete CCT Project Demonstration	N/A
C. FUEL CELLS	Cathode Stability Life Extension; New Metals	Cost-Effective Manufacturing; Fuel Cell and Gas Turbine Integration; Integrated Tests for Syngas	Complete Molten Carbonate Demonstration	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Other Advanced Systems (Continued)				
D. MHD	Seed Regeneration; High Temperature Materials	Channel Development; Integrated System Operation	N/A	N/A
E. COAL-FUELED DIESEL	Control of Coal Water Slurry Additives; Emissions Assessment and Reduction	Fuel Nozzle Development; Erosion Resistant Materials	Complete CCT Project Demonstration	International Marketing Assistance

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE	
		Coal Conversion			
A. PRODUCTION OF SYNTHESIS GAS	N/A	N/A	N/A	N/A	
B. CONVERSION OF SYNTHESIS GAS					
Hydrogen	Improved Conversion Catalyst and H ₂ Technology	N/A	N/A	N/A	
Synthesis Natural Gas	N/A	N/A	N/A	N/A	
Methanol	New Process Approaches and Improved Catalyst	N/A	Complete CCT Project Demonstration	N/A	
Indirect Liquefaction	Slurry Phase Fischer-Tropsch Technology	N/A	N/A	N/A	

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Coal Conversion (Continued)				
C. MILD GASIFICATION	N/A	N/A	Complete Current Programs	International Marketing Assistance
D. DIRECT LIQUEFACTION	Coal Structure & Chemistry; New Concepts	N/A	N/A	N/A
E. OTHER CONVERSION TECHNOLOGIES				
Solvent Extraction	Solvent Properties and Recovery	N/A	N/A	N/A
Bioconversion	Mimetic Catalysts and Reaction Rates	N/A	N/A	N/A

EXHIBIT 1 (Continued)

**RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIALIZATION NEEDS
OF COAL UTILIZATION TECHNOLOGY**

TECHNOLOGY	RESEARCH	DEVELOPMENT	DEMONSTRATION	COMMERCIAL ASSISTANCE
Coal Conversion (Continued)				
E. OTHER CONVERSION TECHNOLOGIES (Continued)				
Coal Bed Methane	Low Cost Water Disposal Methods; Data for Coal Seams	N/A	N/A	N/A
Underground Gasification	N/A	Gas Clean-Up	Complete Demonstration	N/A
F. IRON AND STEEL PRODUCTION	N/A	N/A	Complete Demonstration	N/A

EXHIBIT 2

RESEARCH TECHNICAL PRIORITIES COAL UTILIZATION TECHNOLOGY

TECHNOLOGY

1. HAZARDOUS AIR POLLUTANTS CONTROL
2. PRESSURIZED FLUIDIZED BED, ADVANCED GAS TURBINES, STEAM TURBINES, ADVANCED PULVERIZED COAL-FIRED BOILERS, AND RECUPERATORS
3. ELECTROSTATIC PRECIPITATORS, FABRIC FILTERS, FGD and SCR SYSTEMS
4. FUEL CELLS
5. CARBON DIOXIDE CONTROL
6. SELECTIVE CATALYTIC REDUCTION (SCR)
7. CONVERSION OF SYNTHESIS GAS
8. BIOLOGICAL COAL CLEANING

NEEDS

- Control of Mercury and Other Heavy Metals Emissions
- Erosion, Corrosion, and Oxidation Resistant Metallic and Ceramic Materials and Coatings
1. Characterize All Effluent Streams and Performance of ESP, Fabric Filters, FGD and SCR Systems
 2. Topping System for Fine Particulate Control
- Cathode Life Improvement
- Post-Combustion Control and Sequestration Processes
- Advanced Formulations
- CO Conversion, Catalyst Chemistry, and Slurry Processes
- Reaction Kinetics; Selectivity and Economics

EXHIBIT 3

DEVELOPMENT TECHNICAL PRIORITIES COAL UTILIZATION TECHNOLOGY

TECHNOLOGY

NEEDS

- | | |
|--|---|
| 1. INTEGRATED GASIFICATION COMBINED
CYCLE SYSTEMS | Hot Gas Clean-Up |
| 2. ADVANCED GAS TURBINES | Oxidation and Corrosion Resistance Coatings for Metallic
and Ceramic Materials; Catalytic Combustion |
| 3. HAZARDOUS AIR POLLUTANTS CONTROLS | Mercury Control |
| 4. PRESSURIZED FLUIDIZED BEDS | Hot Gas Clean-Up; Accelerated Topping Combustor
Development |
| 5. FUEL CELLS | Cost-Effective Manufacturing; Fuel Cell/GT Integration |
| 6. WET FGD | Improved Mist Eliminator (High Velocity Scrubbers) |

EXHIBIT 4

DEMONSTRATION TECHNICAL PRIORITIES COAL UTILIZATION TECHNOLOGY

TECHNOLOGY

1. PRESSURIZED FLUIDIZED BEDS
2. INTEGRATED GASIFICATION COMBINED CYCLE
3. ADVANCED PULVERIZED COAL BOILERS
4. HAZARDOUS AIR POLLUTION SYSTEM CONTROL
5. INDIRECT FIRED CYCLES
6. FUEL CELLS
7. BYPRODUCT UTILIZATION
8. SO_x/NO_x CONTROL

NEEDS

- Complete Ongoing CCT Projects Demonstration
- Complete Ongoing CCT Project Demonstration
- Complete LEBS Program
- Characterize All Effluents from CCT Projects Demonstration
- Complete CCT Project Demonstration
- Complete Molten Carbonate Demonstration
- Utilization of Key Solid Streams of CCT Projects
- Complete CCT Projects Demonstrations; Evaluate Economics

EXHIBIT 5

COMMERCIAL ASSISTANCE PRIORITIES COAL UTILIZATION TECHNOLOGY

TECHNOLOGY

NEEDS

1. INTEGRATED COAL GASIFICATION COMBINED
CYCLE SYSTEMS

Risk Sharing

2. ADVANCED PRESSURIZED FLUIDIZED BED SYSTEMS

Risk Sharing

3. PHYSICAL COAL CLEANING

International Marketing Assistance

4. LOW RANK COAL BENEFICIATION

International Marketing Assistance

5. BYPRODUCT UTILIZATION

Develop National Utilization Standards

6. COAL-FIRED DIESEL ENGINES

International Marketing Assistance

Appendix B

Description of the National Coal Council

APPENDIX B

DESCRIPTION OF THE NATIONAL COAL COUNCIL

Recognizing the valuable contribution of the industry advice provided over the years to the Executive Branch by the National Petroleum Council and the extremely critical importance of the role of coal to America and the world's energy mix for the future, the idea of a similar advisory group for the coal industry was put forward in 1984 by the White House Conference on Coal. The opportunity for the Coal industry to have an objective window into the Executive Branch drew overwhelming support.

In the fall of 1984, the National Coal Council was chartered; and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which, in turn, could lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The National Coal Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of the Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry about which the Secretary may request its expertise.

Members of the National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and all geographical regions. The National Coal Council is headed by a Chairman and a Vice-Chairman who are elected by the Council.

The Council is supported entirely by voluntary contributions from its members. It receives no funds whatsoever from the Federal Government. In reality, by conducting studies at no cost which otherwise might have to be conducted by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry or the views of any one particular part of the country. It is, instead, to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the

A CRITICAL REVIEW OF EFFICIENT AND ENVIRONMENTALLY SOUND
COAL UTILIZATION TECHNOLOGY

Appendix B: Description of the National Coal Council

requested study. The first major studies undertaken by the National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the startup of the Council.

Reports of the National Coal Council completed through May of 1995:

June 1986	<i>Coal Conversion</i>
June 1986	<i>Clean Coal Technologies</i>
June 1986	<i>Interstate Transmission of Electricity</i>
June 1986	<i>Report on Industrial Boiler New Source Performance Standards</i>
June 1987	<i>Reserve Data Base: Report of The National Coal Council</i>
June 1987	<i>Improving International Competitiveness of U.S. Coal and Coal Technologies</i>
November 1988	<i>Innovative Clean Coal Technology Deployment</i>
December 1988	<i>The Use of Coal in the Industrial, Commercial, Residential and Transportation Sectors</i>
June 1990	<i>Industrial Use of Coal and Clean Coal Technology -- Addendum Report</i>
June 1990	<i>The Long Range Role of Coal in the Future Energy Strategy of the United States</i>
January 1992	<i>The Near Term Role for Coal in the Future Energy Strategy of the United States</i>
January 1992	<i>Improving Coal's Image: A National Energy Strategy Imperative</i>
May 1992	<i>Special Report on Externalities</i>
February 1993	<i>The Role of U.S. Coal in Energy, the Economy, and the Environment -- Special Report</i>

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Appendix B: Description of the National Coal Council

February 1993	<i>A Synopsis of the Reports (1986-1992)</i>
November 1993	<i>The Export of U.S. Coal and Coal Technology</i>
February 1994	<i>Clean Coal Technology for Sustainable Development</i>
May 1995	<i>A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology</i>

Members of the National Coal Council who have served as Chairman:

June 1985 - June 1986	The Late Honorable John N. Dalton Former Governor of Virginia B. R. Brown President, Consolidated Coal Company
June 1986 - June 1987	James W. McGlothlin Chairman, The United Companies
June 1987 - June 1989	James G. Randolph Former President, Kerr-McGee Coal Company Former Assistant Secretary for Fossil Energy, United States Department of Energy
June 1989 - May 1991	William Carr President, Jim Walter Resources, Inc.
May 1991 - May 1992	W. Carter Grinstead, Jr. Former Vice-President, Exxon Coal and Minerals Company
May 1992 - May 1994	William R. Wahl Vice President, AMAX, Inc.
May 1994 - Present	Joseph W. Craft III President, MAPCO COAL Inc.

Appendix C

The National Coal Council Membership Roster

APPENDIX C

THE NATIONAL COAL COUNCIL MEMBERSHIP ROSTER

JAMES R. ALDRICH
State Director
The Nature Conservancy
Kentucky Chapter

DR. SY ALI
Manager, Industrial Engine Technology
Allison Engine Company

BARBARA F. ALTIZER
Executive Director
Virginia Coal Council

JOHN Q. ANDERSON
Executive Vice President, Coal Business
Group
Burlington Northern Railroad

CHARLES J. BAIRD
Baird, Baird, Baird & Jones, P.S.C.

WILLIAM B. BALES
Vice President, Coal Marketing
Norfolk Southern Corporation

THE HON. GERALD BALILES
Hunton & Williams

C. A. BAYENS
President
Shell Synthetic Fuels Inc.

DR. JANOS M. BEER
Professor Emeritus of Chemical
Engineering
Director, Combustion Research Facility
Massachusetts Institute of Technology

FRANK J. BENNER
President and Chief Operating Officer
Cogentrix, Inc.

JACQUELINE F. BIRD
Director, Ohio Coal Development Office
Ohio Department of Development

DR. SANDY BLACKSTONE
Natural Resources Attorney/Consultant

WILLIAM H. BOWKER
Executive Director
Kentucky Coal Marketing and Export
Council

GREGORY BOYCE
President
Kennecott Energy Company

L. G. BRACKEEN
Vice President, Fuel and Energy
Management
Houston Lighting and Power Company

JULIAN J. BRIX
General Manager
Cooperative Power Association

A CRITICAL REVIEW OF EFFICIENT AND ENVIRONMENTALLY SOUND
COAL UTILIZATION TECHNOLOGY

Appendix C: The National Coal Council Membership Roster

TERRI L. BRONOCCO
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A CRITICAL REVIEW OF EFFICIENT AND ENVIRONMENTALLY SOUND
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Appendix C: The National Coal Council Membership Roster

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Appendix D

The National Coal Council Coal Policy Committee

APPENDIX D

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Appendix F

**The National Coal Council Working Group for the
Report *A Critical Review of Efficient and
Environmentally Sound Coal Utilization Technology***

APPENDIX F

THE NATIONAL COAL COUNCIL WORKING GROUP FOR THE REPORT A CRITICAL REVIEW OF EFFICIENT AND ENVIRONMENTALLY SOUND COAL UTILIZATION TECHNOLOGY

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- Suzanne Langevin, National Coal Council
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- Julie Taylor, Allison Engine Company
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Appendix H

Glossary of Terms

APPENDIX H

GLOSSARY OF TERMS

ACAA	American Coal Ash Association
acfm	Cubic feet of air per minute
AFBC	Atmospheric fluidized bed combustion
AGTCC	Advanced gas turbine combined cycle
AISI	American Iron and Steel Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing Materials
atm	Atmosphere (pressure)
ATS	Advanced turbine system
bbf	Barrel
BCF	Billion cubic feet
bhp.hr	Brake horsepower hour
BFB	Bubbling fluidized bed
bpd	Barrels per day
CAAA	Clean Air Act Amendments
CCPG	Combined cycle power generation
CCT	Clean Coal Technology
CDCC	Coal diesel combined cycle
CDIF	Component Development Integration Facility
CFB	Circulating fluidized bed
CGCC	Coal gasification combined cycle
CWF	Coal-water fuel
DBT	Dibenzothophene
DEA	Diethanol amine
DME	Dimethyl ether
DoD	Department of Defense
DOE	Department of Energy
ECS	Emission control system
EDS	Exxon Donor Solvent
Eff	Efficiency
EIA	Energy Information Administration
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
ESP	Electrostatic precipitator

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FBC	Fluidized bed combustion or combustor
FGD	Flue gas desulfurization
FOAK	First-of-a-kind
GDP	Gross domestic product
GW	Gigawatt (one billion watts)
GWe	Gigawatt (electric energy)
HAP	Hazardous air pollutant
HGCU	Hot gas clean-up
HHV	Higher heating value (assumes recovery of water energy as liquid)
HIPPS	High performance power system
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
IHPTET	Integrated high performance turbine system technology
JBR	Jet Bubble Reactor
JISF	Japan Iron and Steel Federation
kV	Kilovolt (one thousand volts)
kWh	Kilowatt hour
LHV	Lower heating value (assumes recovery of water energy as vapor)
LNB	Low NO _x burner
LPMEOH	Liquid phase methanol
LRC	Low rank coal
MACT	Maximum achievable control technology
MBtu	Million British thermal units
MCF	Million cubic feet
MCFC	Molten carbonate fuel cell
MCL	Molten caustic leaching
MEA	Monoethanol amine
MHD	Magnetohydrodynamics
MITI	Ministry of International Trade and Industry (Japan)
MTPY	Million tons per year
MW	Megawatt (one million watts)
MWC	Municipal waste combustion
MWe	Megawatt (electric energy)
NOXSO	Proprietary SO ₂ and NO _x control process
NSPS	New source performance standards
OFA	Over-fire air
ORNL	Oak Ridge National Laboratory
PAFC	Phosphoric acid fuel cell

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PCC	Physical coal cleaning
PCF	Pulverized coal-fired
PCFB	Pressurized circulating fluidized bed
PETC	Pittsburgh Energy Technology Center
PFBC	Pressurized fluidized bed combustion
PM10	Less than 10 microns
POC	Proof of concept
ppb	Parts per billion
ppm	Parts per million
ppt	Parts per trillion
PRDA	Program research and development announcement
PSA	Pressure swing regeneration
psia	Pounds per square inch (absolute) pressure
RCRA	Resource Conservation and Recovery Act
RDF	Refuse-derived fuel
SARA	Superfund Amendments and Reorganization Act
scf	Standard cubic foot
SCR	Selective catalytic reduction
SLS	Solid-liquid separation
SNCR	Selective non-catalytic reduction
SNG	Synthetic natural gas
SNOX	Proprietary SO ₂ and NO _x control process
SNRB	Proprietary SO ₂ and NO _x control process
SOFC	Solid oxide fuel cell
TCF	Trillion cubic feet
t/h	Tons per hour
tph	Tons per hour
TPY	Tons per year
TSA	Thermal swing adsorption

Appendix I

**Correspondence Between National Coal Council and
U.S. Department of Energy**



The Secretary of Energy
Washington, DC 20585

May 3, 1994

Mr. William R. Wahl
Chairman
National Coal Council
Post Office Box 17370
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Dear Mr. Wahl:

Please extend my thanks to the National Coal Council for its excellent study on future directions for the Clean Coal Program. It was helpful to the Department as we prepared the Department's Report to Congress on the Clean Coal Program.

We urge the Council to use your recent study as the basis of a comprehensive compilation of state-of-the-technology for coal using systems and the associated benefits. This single source document would be valuable to potential customers of clean coal technologies.

Your study provided valuable information on significant advancements in technology that are evolving as a consequence of the Clean Coal Program. This technological progress offers both an export opportunity and the means to respond domestically to the energy and environmental demands of the 21st century. But to realize this potential, it is essential that the customers for these technologies have access to relevant information. A single source document could meet this important need.

Thank you for considering this request.

Sincerely,


Hazel R. O'Leary

THE NATIONAL COAL COUNCIL, INC.

Post Office Box 17370, Arlington, Virginia 22216

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May 12, 1994

The Honorable Hazel O'Leary
Secretary
United States Department of Energy
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Washington, DC 20585

Dear Madam Secretary:

On behalf of the members of the National Coal Council, please accept my most sincere gratitude for being with us at our recent Council reception. The members, our guests, and I were all very honored to have you join us.

Above all, we are extremely appreciative for the personal attention and time you shared with each one of us. In an organization such as the Council, where the members continually give so much of their own time and support, a chance to spend quality time with those that we do our work most directly for is the highest thanks and the best motivation.

We thank you also for your recent request for a study on the latest clean coal technologies. The work is already underway and we look forward to serving you through another quality report.

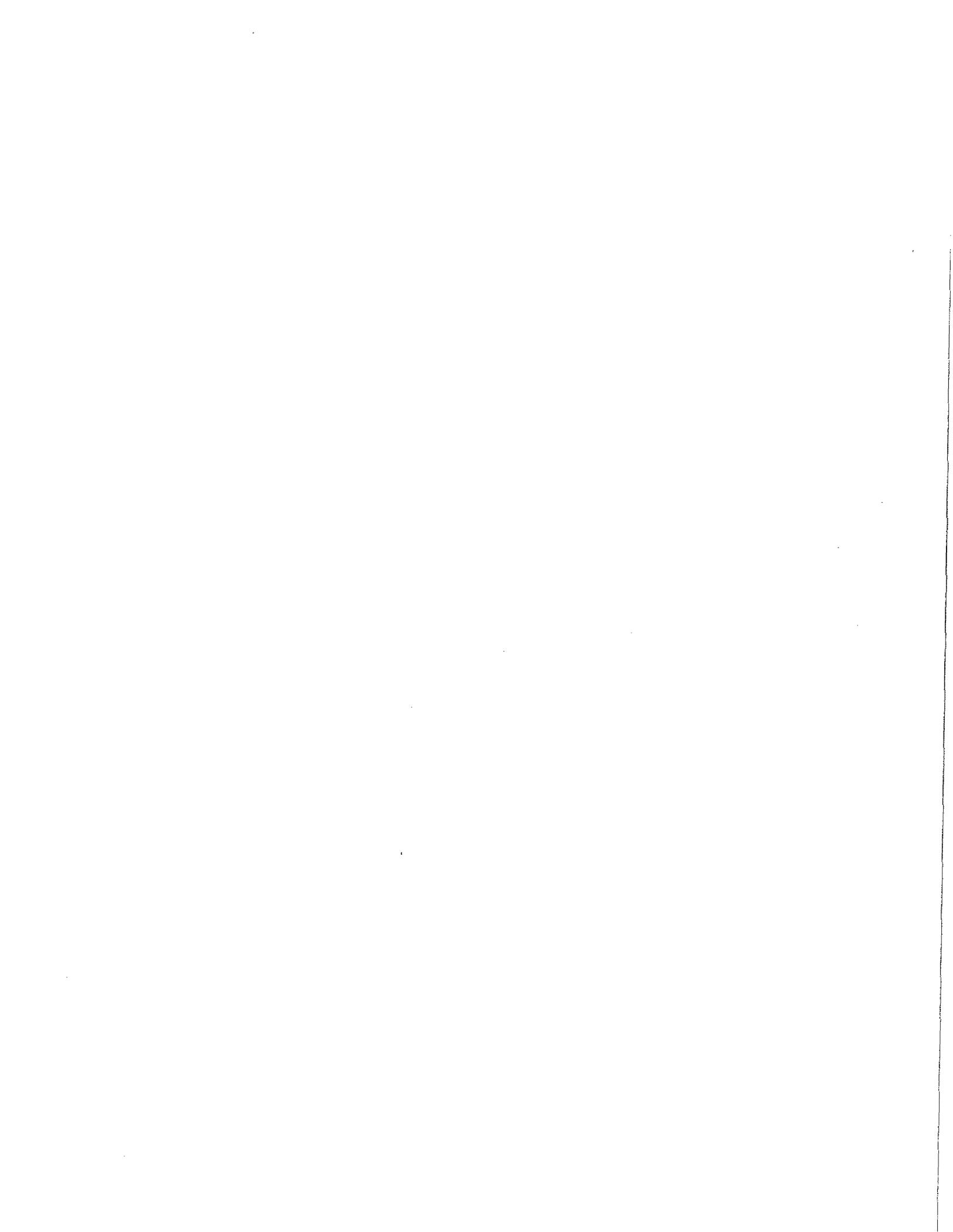
Again, Madam Secretary, our most sincere thanks for being with us. We hope that we may be able to meet again with you soon.

Our very best wishes for your continued success.

Yours very truly,



Joseph W. Craft III
Chairman



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